01-M-0075
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Testimony

nationalgrid

Carlos A. Gavilondo
General Counsel, New York Distribution

RECEIVED PUBLIC SERVICE COMMISSION EXEC-FILES-ALBANY

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September 15, 2006

VIA ELECTRONIC MAIL AND U.S. MAIL

Honorable Jeffrey E. Stockholm
Administrative Law Judge
NYS Department of Public Service
3 Empire State Plaza
Albany, New York 12223

Re: Case 01-M-0075 – Joint Petition of Niagara Mohawk Holdings, Inc., Niagara Mohawk Power Corporation, National Grid Group PLC and National Grid USA for Approval of Merger and Stock Acquisition – Staff Audit of Deferral Account – Corrections to September 1, 2006 Pre-Filed Testimony of Patrick M. Pensabene

Dear Judge Stockholm:

Niagara Mohawk Power Corporation, d/b/a National Grid ("National Grid" or "Company") hereby submits two corrections to the September 1, 2006 pre-filed testimony of Patrick M. Pensabene submitted in this case. Specifically, at page 18, lines 17-20 of Mr. Pensabene's September 1, 2006, testimony, the witness references the Company's response to information request ("I/R") RAV-70 (NMPC-305), for the proposition that the Company had accepted Staff's proposed adjustment relating to "Transportation- Pooled Vehicle Costs." However, in quantifying that accepted adjustment, the Company stated the incorrect amount. The correct adjustment amount should have been $322,188, rather than $257,307. The corrected testimony reflects this change. In addition, a correction is made to page 19, line 6 of the testimony to correct an error to an exhibit reference.

Attached hereto are revised pages 18 and 19 of Mr. Pensabene's pre-filed testimony in marked-to-show-changes and clean formats reflecting the aforementioned changes. These pages should be substituted in place of the corresponding pages included in the September 1, 2006 filing. Copies of this filing are being served today on the Secretary, Staff, and all other parties on the Active Parties list.

Thank you for your attention to this matter.

Respectfully submitted,

Carlos A. Gavilondo

cc: Active Parties 01-M-0075 (electronic mail only)

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Testimony of Patrick Pensabene
Revised Pages Filed September 15, 2006

any rational correlation between the damage estimates reported on the NCDC website and the actual incremental restoration costs incurred by the Company that are the subject of this deferral, it would be arbitrary and unreasonable to attempt to allocate costs between the two days using the NCDC information. Staff's response does not fill this gap in its case.

Q: Staff assumes in its testimony that the Company proposes to reduce the deferral balance and apportion $75,214 to costs incurred on January 31, 2002; is that an accurate assumption?

A: No. This was simply the Company's response to Staff's question in IR RAV-45(E) (NMPC-269(E)) asking the amount of incremental storm costs actually incurred on January 31, 2002.

Q: Moving to Staff's second proposed adjustment, do you agree with Staff's contention that "Transportation-Pooled Vehicles Costs" are provided for in the Merger Joint Proposal base rates and therefore are not deferrable because they do not represent an incremental expense?

A: Yes. As stated in response to IR RAV-70 (#305) question G, and identified in Staff Panel testimony page 89, the Company agrees with Staff's conclusion and therefore proposes to remove the total "Transportation-Pooled Vehicle Costs" ($322,188) from the deferral account.

Q: Will the adjustment for "Transportation-Pooled Vehicle Costs" impact the adjustment you proposed for Storm #55645?

A: Yes. The adjustment for Storm #55645 included incremental transportation costs in the calculation and these same costs are included in the proposed adjustment above; therefore it is necessary to eliminate the duplication. As shown in Exhibit __ (PMP-2), the proposed adjustment for Storm #55645 included approximately $13,000 of incremental transportation costs ($867 + 15.3% of $76,547). The final adjustment for Storm #55645 is therefore $2,176,759.

Q: Do you agree with Staff's proposed adjustment to eliminate $49,117 from the Major Storm Cost deferral for Management Overtime relating to Storm #82950 on the basis that the overtime was late-occurring and unsupported?

A: No. In Exhibit ___ (PMP-5), the Company's response to IR RAV-43 (NMPC-267), the Company provided supporting documentation (Attachment 4) detailing the 30 employees whose overtime was paid in December 2003 and individual Management Overtime timesheets (Attachment 5) for 24 of those 30 employees.

Q: What information can be gathered from those Management Overtime timesheets contained in Exhibit ___ (PMP-5)?

A: Storm #82950 began on September 18, 2003 and ended on September 21,

Testimony of Patrick Pensabene
Revised Pages Filed September 15, 2006
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any rational correlation between the damage estimates reported on the NCDC website and the actual incremental restoration costs incurred by the Company that are the subject of this deferral, it would be arbitrary and unreasonable to attempt to allocate costs between the two days using the NCDC information. Staff's response does not fill this gap in its case.

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Q: Moving to Staff's second proposed adjustment, do you agree with Staff's contention that "Transportation-Pooled Vehicles Costs" are provided for in the Merger Joint Proposal base rates and therefore are not deferrable because they do not represent an incremental expense?

A: Yes. As stated in response to IR RAV-70 (#305) question G, and identified in Staff Panel testimony page 89, the Company agrees with Staff's conclusion and therefore proposes to remove the total "Transportation-Pooled Vehicle Costs" ($322,188) from the deferral account.

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A: Yes. The adjustment for Storm #55645 included incremental transportation costs in the calculation and these same costs are included in the proposed adjustment above; therefore it is necessary to eliminate the duplication. As shown in Exhibit __ (PMP-2), the proposed adjustment for Storm #55645 included approximately $13,000 of incremental transportation costs ($867 + 15.3% of $76,547). The final adjustment for Storm #55645 is therefore $2,176,759.

Q: Do you agree with Staff's proposed adjustment to eliminate $49,117 from the Major Storm Cost deferral for Management Overtime relating to Storm #82950 on the basis that the overtime was late-occurring and unsupported?

A: No. In Exhibit ___ (PMP-5), the Company's response to IR RAV-43 (NMPC-267), the Company provided supporting documentation (Attachment 4) detailing the 30 employees whose overtime was paid in December 2003 and individual Management Overtime timesheets (Attachment 5) for 24 of those 30 employees.

Q: What information can be gathered from those Management Overtime timesheets contained in Exhibit ___ (PMP-5)?

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STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

Case No. 01-M-0075

Niagara Mohawk Power Corporation d/b/a National Grid

SECOND
COMPETITIVE TRANSITION CHARGE
RESET
DEFERRAL ACCOUNT AUDIT

REBUTTAL TO DPS STAFF REPLY TESTIMONY OF SEPTEMBER 2006

September 26, 2006

Volume One

TESTIMONY

nationalgrid

Niagara Mohawk Power Corporation d/b/a National Grid
Case No. 01-M-0075

SECOND
COMPETITIVE TRANSITION CHARGE
RESET
DEFERRAL ACCOUNT AUDIT

REBUTTAL TO DPS STAFF REPLY TESTIMONY OF SEPTEMBER 2006

Volume One

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Filing Letter

nationalgrid

Carlos A. Gavilondo
General Counsel, New York Distribution

September 26, 2006

VIA HAND DELIVERY

Honorable Jeffrey E. Stockholm
Administrative Law Judge
NYS Department of Public Service
3 Empire State Plaza
Albany, NY 12223

Re: **Case No. 01-M-0075 – Joint Petition of Niagara Mohawk Holdings, Inc., Niagara Mohawk Power Corporation, National Grid Group PLC and National Grid USA for Approval of Merger and Stock Acquisition – Staff Audit of Deferral Account**

Dear Judge Stockholm:

Enclosed please find the rebuttal testimonies and exhibits of Niagara Mohawk Power Corporation, d/b/a National Grid, in response to the responsive testimony and exhibits submitted September 19, 2006 by the Staff of the Department of Public Service ("Staff") in this case. Complete and redacted copies were also served upon Jane C. Assaf, Staff Counsel, and well as directly upon on-site Staff. The Secretary and all other active parties have either received or are being provided redacted copies only. In addition to in-hand service to yourself, the Secretary and Staff this date, the Company is making the materials available electronically today, and is distributing hard copies of the filing to other parties via overnight mail. To the extent some active parties have requested not to receive a paper copy of the filing, service is being made pursuant to those requests.

Limited portions of the testimony and exhibits have been redacted due to the confidential nature of the materials. Corresponding requests for confidential treatment/trade secret protection have been previously filed with the Department of Public Service's Record Officer for some materials; however, the Company is concurrently submitting a request for confidential treatment/trade secret protection with respect to confidential information that has not previously been submitted to the Department and is being provided with this filing.

Thank you for your attention to this matter.

Sincerely,

Carlos A. Gavilondo

cc: Secretary Brilling – 5 redacted copies via hand delivery
Active Parties – redacted copies via overnight mail

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Service List
Case No. 01-M-0075
09/08/2006

Service List 9/8/06

CASE 01-M-0075
PROPOSED MERGER
NIAGARA MOHAWK & NATIONAL GRID
ACTIVE PARTY LIST
(As of September 8, 2006)

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Rebuttal Testimony of Lawrence J. Reilly

Testimony of
L. J. Reilly

REBUTTAL TESTIMONY OF LAWRENCE J. REILLY

I. Introduction

Q: Please state your name and business address for the record.

A: My name is Lawrence J. Reilly. My business address and credentials were set forth in my responsive testimony, filed in this proceeding on September 1, 2006.

Q: What is the purpose of your rebuttal testimony?

A: I will respond briefly to certain assertions made by Staff witnesses Denise A. Gerbsch and Robert A. Visalli (the "Staff Panel") in their Responsive Testimony filed on September 19, 2006 with respect to the interpretation of the Merger Rate Plan and the implementation of its deferral provisions in this proceeding. I note that although I am not responding to every point made in the Staff Panel testimony, my silence should not be construed as agreement with the arguments presented by the Staff Panel that are not addressed. I also note that, in this rebuttal testimony, I will use defined terms and acronyms with the meanings defined in my responsive testimony.

II. Response to Staff Assertions Concerning the Merger Rate Plan

Q: Do you have any comments on the Staff Panel's interpretation of the Merger Rate Plan?

A: Yes. In its testimony, the Staff Panel describes the Merger Rate Plan in a way that is consistent with the Company's view and my previous testimony. On page 66 of its responsive testimony (lines 6-18), the Staff Panel states:

> The Merger Joint Proposal, like most joint proposals, is an intricately constructed, delicately balanced settlement. There are numerous gives and takes in these settlements, and individual components and terms may not seem all that fair when evaluated individually. However, when taken as a whole, the individually perceived 'unfair' terms result in a fairly balanced overall joint proposal. Indeed, that is why Clause 3.3, which expressly conditions the Merger Joint Proposal upon Commission acceptance of all provisions without change or condition, was included.

I find nothing to quarrel with in this statement, which is entirely consistent with my own descriptions of the Merger Joint Proposal in my responsive testimony (see page 6, lines 13-20, and page 18, lines 1-14). However, many of the positions that the Staff Panel takes with respect to particular deferrals at issue in this proceeding – which are addressed by the other witnesses presenting responsive and rebuttal testimony on behalf of Niagara Mohawk – appear to be inconsistent with its view of the Merger Rate Plan, as expressed in the passage I quoted above. That is, many of the adjustments proposed by Staff are based on Staff's view that the operation of the particular deferral mechanism, as agreed upon among the parties and approved by the Commission, produces a result that is unfair in their eyes. In proposing these adjustments, the Staff Panel loses sight of the integrated, balanced nature of the Joint Proposal.

Q: What implications does the integrated, balanced nature of the Merger Joint Proposal have for this proceeding?

A: I understand the purpose of this proceeding to be to ensure that the Company's entries in the deferral account correctly and accurately implement the provisions of the Merger Joint Proposal. In this way, the "intricately constructed, delicately balanced" structure of the Merger Joint Proposal will be preserved. As I said in my earlier testimony, it is entirely appropriate for Staff and other parties to review the accuracy of the Company's deferrals and their consistency with the provisions of the Merger Joint Proposal for this purpose.

However, it is inappropriate for any party to use this proceeding to attempt to modify the Merger Joint Proposal and, in doing so, upset the balance of "gives and takes" that Staff agrees produced a "fairly balanced overall joint proposal." Notwithstanding its recognition that the Merger Joint Proposal is a fair and balanced package, the Staff Panel's responsive testimony appears to confirm my earlier impression that many of Staff's adjustments represent an unjustified attempt to revise the Merger Joint Proposal, based on Staff's view that individual deferral provisions that have operated in the Company's favor are now "unfair."

Q: Can you provide an example?

A: Yes. In my previous testimony, I pointed to Staff's proposed disallowance of any deferral for station service revenues lost due to the decisions of the Commission, the Federal Energy Regulatory Commission, and the courts as an unwarranted departure from the Merger Joint Proposal and, in particular, a refusal to permit Section 1.2.4.3 of the Merger Joint Proposal, which allows for the deferral of cost and revenue impacts of legal and regulatory changes, to operate as negotiated and accepted by the Commission. The Staff Panel's discussion of this issue in its responsive testimony only serves to confirm the accuracy of this description.

Q: Why is that?

A: As Mr. Bonner and Mr. Leuthauser explain in their responsive and rebuttal testimony, the Staff Panel does not base its opposition to this deferral on a claim that the Company failed to apply the language of Section 1.2.4.3 and other relevant provisions of the Merger Joint Proposal and other settlements. Instead, the Staff Panel chastises the Company for basing its deferral on what the language of Section 1.2.4.3 clearly requires: a comparison of the revenues the Company can charge in light of the regulatory change to those it could have charged if the regulatory change had not occurred. I view the Staff Panel's continued opposition to a deferral that is authorized by and consistent with the Merger Joint Proposal as tantamount to an attempt to modify the "delicately balanced" settlement.

This impression is also confirmed by the Staff Panel's insistence (page 23, line 4 – page 24, line 2) that if the Commission finds the deferral of lost station service revenues to be consistent with the Merger Joint Proposal – as we believe it must – the Commission should exercise the authority reserved in Section 3.5 of the Joint Proposal to disallow the deferral on the ground that Niagara Mohawk's rates are in excess of just and reasonable rates. This demonstrates that the Staff Panel's position rests on its belief that applying Section 1.2.4.3 in accordance with its language leads to an unreasonable outcome on this deferral issue, not on any failure by the Company to calculate the deferral in accordance with the provision's requirements. Even if this were true – which it is not – it represents an abrupt departure from Staff's view, expressed on page 66 (lines 12-14), that the Merger Joint Proposal must be "taken as a whole" and, on that basis, is "a fairly balanced overall joint proposal." It also represents a marked shift in position from Staff's previous testimony, which never mentioned Section 3.5 as a basis for its opposition to the station service lost revenue deferrals.

Q: Do you have any other comments on Staff's reliance on Section 3.5 of the Merger Joint Proposal in its responsive testimony?

A: Yes. Staff's reliance on Section 3.5 is inappropriate in this proceeding and, in any event, does not support its proposed disallowance of all station service lost revenue deferrals. First, as I discussed earlier, this proceeding was established to make sure Niagara Mohawk accurately implemented the deferral provisions of the Merger Rate Plan, not to consider whether those provisions should be changed using the Commission's reserved power to reduce rates that exceed just and reasonable levels.

Second, even if this issue were properly before the Commission in this proceeding, the Staff Panel is proposing to misapply Section 3.5. Section 3.5 establishes as a predicate a finding that the rates established in accordance with the Merger Rate Plan "are in excess of just and reasonable rates for Niagara Mohawk's electric and gas service." The provision thus requires an evaluation of the overall level of the Company's rates, not a review of the reasonableness of any particular deferral item.

Just as Staff agrees that it is the overall balance of the Merger Rate Plan's provisions that demonstrates the reasonableness of the Rate Plan, it is the end result of those provisions that determines whether the resulting rates are in excess of just and reasonable levels.

The Staff Panel does not even attempt to show that Niagara Mohawk's rates, including the recovery of deferred station service lost revenues and the other deferrals at issue, exceed just and reasonable rates for the electric and gas service the Company provides. In fact, I do not see how Staff could make that showing since: (a) as I mentioned in my earlier testimony, Niagara Mohawk's cumulative earnings under the Rate Plan have equaled a return on equity of only 8.69 percent; (b) should the Company's cumulative earnings rise in the future, the Rate Plan requires the Company to share earnings above the specified cap with customers; and (c) Staff has not finished its audit of the Company's earnings through December 31, 2005. Staff's opposition to the deferral of lost station service revenues or any of the other deferrals proposed in this case simply cannot form the basis for the exercise of extraordinary relief under Section 3.5.

III. Conclusion

Q: Thank you. I have no further questions at this time.

Rebuttal Testimony of James J. Bonner Jr. and Scott D. Leuthauser

Testimony of J. J. Bonner, Jr., S. D. Leuthauser

REBUTTAL TESTIMONY OF
JAMES J. BONNER JR. AND SCOTT D. LEUTHAUSER

I. Introduction

Q: Mr. Bonner, please state your name and business address.

A: My name is James J. Bonner Jr. My business address and credentials were set forth in our responsive testimony, filed in this proceeding on September 1, 2006.

Q: Mr. Leuthauser, please state your name and business address.

A: My name is Scott D. Leuthauser. My business address and credentials, too, were set forth in our responsive testimony, filed in this proceeding on September 1, 2006.

Q: What is the purpose of your rebuttal testimony?

A: We will respond briefly to certain assertions regarding the disputed station service lost revenue and standby service lost revenue deferrals made by Staff witnesses Denise A. Gerbsch and Robert A. Visalli (the "Staff Panel") in their Responsive Testimony filed on September 19, 2006. We note that, due to the limited time available, and because we fully described the basis for the deferral in our earlier testimony, we are not responding to every point made in the Staff Panel testimony. Our silence should not be construed as agreement with the arguments presented by the Staff Panel that we do not address. We also note that, in this rebuttal testimony, we will use defined terms and acronyms with the meanings defined in our responsive testimony.

Q: Do you sponsor any exhibits?

A: Yes, we are sponsoring six exhibits. Exhibit _____ (JJB/SDL-6) is a copy of the Company's Response to Information Request ("IR") No. 404 (PSC-340 Visalli (RAV-127)), which addresses the Merger Rate Plan Deferral Account Provisions. Exhibit _____ (JJB/SDL-7) contains excerpts of the electric sales forecast workpapers from Volume 1 of the Financial Forecast and Supporting Workpapers filed in support of the Merger Rate Plan Joint Proposal in this proceeding in January 2001. Exhibit _____ (JJB/SDL-8) is a copy of the Company's Response to IR No. 264 (PSC-209 Visalli (RAV-40)), which addresses the annual sales comparison that was included in the Merger Rate Plan Joint Proposal. Exhibit ___ (JJB/SDL-9) is a copy of the Standby Service Joint Proposal submitted by the Company, Staff, Multiple Intervenors, and others on March 12, 2002 in Case 01-E-1847. Exhibit ___ (JJB/SDL-10) is a copy of Staff's Statement in Support of the Standby Service Joint Proposal, dated March 26, 2002. Exhibit ___ (JJB/SDL-11) is a copy of the Company's

Statement in Support of Standby Service Joint Proposal, dated March 25, 2002.

II. Response to Selected Staff Assertions

Q: Do you have any comments on the Staff Panel's contention (made on page 24, line 8 – page 25, line 20) that the deferral of disputed station service lost revenues is somehow improper because the Company did not convene a meeting as they allege is required by Section 1.2.4.3.1 of the Merger Rate Plan?

A: Yes. As we explained in our earlier testimony, the deferral of disputed station service lost revenues is clearly authorized by Section 1.2.4.3 of the Merger Rate Plan, which provides for the deferral of "all of the effects of any legislative, court, or regulatory change, which imposes new or modifies existing obligations or duties and which, evaluated individually, increases or decreases Niagara Mohawk's revenues or costs" by more than the $2 million annual threshold. We also explained that the Staff Panel did not take issue with the fact that the orders of the Commission, the FERC and the courts that constrain the Company's ability to collect the charges for standby service authorized by its tariff at the time of the Merger Rate Plan constitute legal or regulatory changes within the scope of this provision. In its rebuttal testimony, the Staff Panel again concedes that a legal or regulatory change has taken place.

However, the Staff Panel raises a new argument. It now contends that another provision, Section 1.2.4.3.1 of the Merger Rate Plan, bars the Company from deferring disputed station service lost revenues. This provision provides:

> To the extent that the actions of FERC, the New York ISO, or any other agency having authority over how costs or revenues are allocated to or away from the distribution or transmission function, materially alter the existing ratemaking and/or cost responsibility for retail electric customers, interested parties will reconvene and negotiate in good faith to resolve the impact on electricity delivery rates, if any.

The Staff Panel argues that this provision prohibits the deferral of disputed station service lost revenues because Niagara Mohawk did not convene a meeting to negotiate over the impact of the FERC rulings on station service on delivery rates.

The Staff Panel's new argument is wrong. First, Section 1.2.4.3.1 does not limit the deferrals allowable under Section 1.2.4.3. Rather, it provides an option for alternative treatment of the impact of regulatory decisions that reclassify the Company's costs, which are also addressed in Section 1.2.3.5 of the Merger Joint Proposal. Second, the regulatory and court rulings that limit Niagara Mohawk's recovery of charges for the delivery of standby service do not reclassify costs between the distribution and transmission functions, and so do not come within the requirements of Section 1.2.4.3.1.

Q: Why do you say that Section 1.2.4.3.1 does not limit deferrals under Section 1.2.4.3?

A: Our statement that Section 1.2.4.3.1 does not limit the eligibility of costs or revenues affected by legal or regulatory change for deferral under Section 1.2.4.3 is based on what the language of the two provisions says. Section 1.2.4.3 provides for the deferral of costs and revenues affected by a legal or regulatory change, and does not require the parties first to conduct negotiations under Section 1.2.4.3.1 before those costs or lost revenues may be deferred. Staff's attempt to read such a prerequisite into Section 1.2.4.3 would turn the provision into a dead letter, effectively allowing the Company to defer the cost or revenue impact of legal or regulatory changes only if the other parties first agree. Treating Section 1.2.4.3 as an agreement-to-attempt-to-agree on deferrals is clearly inconsistent with its language and purpose.

Q: If Section 1.2.4.3.1 does not limit deferrals under Section 1.2.4.3, what does it do?

A: Section 1.2.4.3.1 simply provides an alternative remedy to deferrals for the impact of regulatory decisions that "materially alter" the allocation of costs between the transmission and distribution functions. As such, the provision relates back to Section 1.2.3.5 of the Merger Joint Proposal, which allows a prospective rate change to reflect the impact of such reallocation decisions. This provision was included in the Merger Rate Plan to deal with the possibility that an event such as a spin-off of Niagara Mohawk's transmission facilities or a change in the classification of facilities between transmission and distribution might increase the extent of FERC jurisdiction over the Company's delivery facilities. In that event, it would make sense for the parties to reconvene to consider how and whether electric delivery rates might be affected, since such events would normally affect delivery rate design generally. Doing so would afford them the opportunity to decide if any compensating adjustments are required to ensure that the combined delivery rate (transmission plus distribution) would remain at the agreed-upon level after the spin-off or other event.

Moreover, Section 1.2.4.3 allows for such reclassification decisions to be addressed through prospective adjustments under Section 1.2.3.5, rather than through deferrals. It does so by providing for the deferral of the cost and revenue impact of legal and regulatory changes "[u]nless otherwise provided for in Section 1.2.3.5." This shows that all of the sections were designed to work together: a regulatory decision affecting the allocation of costs between the transmission and distribution functions that results in a prospective adjustment to delivery rates under Section 1.2.3.5, following discussions held under Section 1.2.4.3.1, would not also result in deferrals under Section 1.2.4.3.

Q: Please explain why the regulatory changes that create the disputed station service lost revenues are not within Section 1.2.4.3.1's requirement for renegotiation.

A: The regulatory and court decisions affecting station service revenues are not the kind of facility cost allocation decisions that are covered by the language or intent of Section 1.2.4.3.1 and Section 1.2.3.5. Facilities have not been shifted between the transmission and distribution function or transferred to another corporate entity. Instead, FERC has required the use of a monthly netting to determine when standby service is provided and to measure the quantity of that service, and its decisions have been upheld by the reviewing court. This is not a facility cost allocation decision that is the subject of this provision.

Q: Has the Company held any meetings with the Parties on the standby service issue?

A: Yes. As we explained in our previous testimony (on page 9), on November 28, 2001, the Company made a compliance filing to implement the Commission's guidelines for standby rates to generators. That filing was followed by numerous meetings among substantially the same parties who participated in the negotiations leading to the Merger Joint Proposal, which produced the Standby Service Joint Proposal accepted by the Commission on June 21, 2002 in Case No. 01-E-1847. A copy of the Joint Proposal the Company, Staff, Multiple Intervenors, and others submitted in Case 01-E-1847 on March 12, 2002, is attached as Exhibit ___ (JJB/SDL-9). In addition, we have attached copies of the Staff's Statement in Support of Joint Proposal, dated March 26, 2002, and the Company's Statement in Support of Joint Proposal, dated March 25, 2002, as Exhibit ___ (JJB/SDL-10) and Exhibit ___ (JJB/SDL-11), respectively.

The discussions leading to the Standby Service Joint Proposal addressed all aspects of rate design and cost allocation for standby service rates. As a result of those discussions, the Parties agreed on cost allocation issues associated with the change in standby service rates, but continued to rely on the Merger Rate Plan (primarily Section 1.2.4.17, discussed in our earlier testimony) to deal with the deferral of revenues lost as a result of the change. Therefore, for the cost allocation issues associated with the Standby Lost Revenue Settlement, Niagara Mohawk has satisfied fully any obligations to hold meetings with the Parties under Section 1.2.4.3.1. In its initial filing in this Second CTC Reset proceeding, the Company expressed its willingness to hold similar meetings to address the disputed station service revenues, even though there is no cost allocation issue involved (*see* Second CTC Reset Compliance (July 29, 2005), Attachment 6 at page 49 of 71, footnote 11), but such consultations are not a prerequisite for deferrals under Section 1.2.4.3.

Q: Do you have any comments on the Staff Panel's parsing of the language of Section 1.2.4.3.1 on page 25 of its rebuttal testimony?

A: Yes. The Staff Panel says that the reference in Section 1.2.4.3.1 to "electricity delivery rates, if any" supports its view that any deferral under Section 1.2.4.3 must be measured by the impact of regulatory change on those rates, rather than on the revenues the Company would have realized without the regulatory change. The difference between the two possibilities Staff is comparing is difficult to see: when a legal or regulatory change limits the Company's ability to charge delivery rates authorized in its tariff – as Staff concedes to be true in the case of station service – that change impacts both the rates themselves and the revenues the Company could have collected but for the change. If Staff is trying to say that the language of Section 1.2.4.3.1 supports its view that the effect of a legal or regulatory change on the Company's revenue must be compared to a line item in the sales forecast submitted with the Merger Rate Plan, we must disagree. There is no reference to that forecast or its components in Section 1.2.4.3.1.

Moreover, there is an additional, more basic problem with Staff's argument: it is parsing the wrong section of the Merger Rate Plan. Section 1.2.4.3 of the Rate Plan, not Section 1.2.4.3.1, authorizes the deferral of the cost and revenue impacts of legal and regulatory changes. The plain language of Section 1.2.4.3 makes it clear that "all of the effects" of a legal or regulatory change on "Niagara Mohawk's revenues . . . from regulated electric operations" may be deferred if the annual impact is greater than $2 million. The obvious way to measure the effect of a regulatory change on the Company's revenues is to compare the revenues the Company is permitted to collect after the change with those it could have collected if the change had not occurred.

If anything, Section 1.2.4.3.1 supports this straightforward reading of Section 1.2.4.3. Any discussions under Section 1.2.4.3.1 of the impact of decisions affecting cost allocation would, as we have discussed, be directed toward implementing Section 1.2.3.5, which requires any prospective rate change associated with a reclassification to be implemented in a revenue neutral manner and specifically bars any under-recovery of electric delivery revenues as a result of the reclassification decision. Section 1.2.4.3.1 therefore does not contemplate the massive disallowance the Staff Panel is advocating in this case.

Q: Do you have any comments on the Staff Panel's assertions on page 12, line 11 – page 13, line 18, that this plain reading of Section 1.2.4.3 will open the door to "staggering" problems, including hundreds of millions of dollars of new deferrals?

A: Yes. Staff's concerns are groundless. Staff's parade of horrible consequences is based on a misrepresentation of the Company's position. We did not testify that the cost of service submitted to support the Merger Rate Plan rates has no relevance to the operation of any of the deferral mechanisms included in the Joint Proposal. To the contrary, both we and Mr. Reilly explicitly noted that there were numerous deferral provisions that specifically authorized the deferral only of changes in an element of Niagara Mohawk's cost of service, as compared with a specified baseline derived from the Merger Rate Plan cost of service (see our responsive testimony at page 38, line 18 – page 39, line 11, and Mr. Reilly's responsive testimony at page 22, lines 3-7). But Section 1.2.4.3, authorizing the deferral of the cost and revenue impact of legal and regulatory changes, is not one of them. In an information request response (IR No. 404 (PSC-340 Visalli (RAV-127)) submitted on September 12, 2006, the Company described how different categories of deferrals would be determined under the Merger Rate Plan. A copy of this response is included as an exhibit to our rebuttal testimony. See Exhibit __ (JJB/SDL-6). As that exhibit demonstrates, there is no requirement in Section 1.2.4.3 that the impact of a legal or regulatory change on the Company's revenues from a particular service classification must be measured against the original forecast for revenues from that same service classification. Such a requirement is unnecessary to ensure that the amounts eligible for deferral under Section 1.2.4.3 can be readily identified and audited by comparison of the revenues the Company is authorized to collect before and after the legal or regulatory change. Implementing Section 1.2.4.3 in accordance with the terms agreed upon among the parties and approved by the Commission therefore will not have the widespread dire consequences hypothesized by Staff.

Q: Do you have any comments on the Staff Panel's statement on page 21, lines 11-15, that Staff was not aware until March 2005 "that station service related revenues were not built into the Merger Joint Proposal rates"?

A: Yes. We find this statement curious because the basis for the sales forecast underlying the Merger Rate Plan rates was fully disclosed in the negotiations and was described in the workpapers filed with the Merger Joint Proposal. The workpapers supporting the sales forecast were included as pages 60-145 of Volume 1 of the Financial Forecast and Supporting Workpapers filed in support of the Merger Rate Plan Joint Proposal in this proceeding in January 2001. We have included excerpts from those workpapers in Exhibit ___ (JJB/SDL-7). Page 69 of the workpapers (page 1 of the exhibit) summarizes the overall sales forecast by customer class; pages 107-108 of the workpapers (pages 2 and 3 of the exhibit) show the breakdown by customer class, including unregulated generators receiving standby service and other large commercial and industrial customers.

There was, therefore, ample information available to Staff showing the basis of the sales forecast well before March 2005. Moreover, contrary to the Staff Panel's assertion (on page 19, lines 8-15), the fact that the sales forecast did not include a separate forecast of sales of standby service or permit the identification of the portion of overall sales attributable to standby service customers neither undermines the basis for the deferrals of lost station service revenues nor renders Niagara Mohawk's rates excessive if it recovers those deferrals.

Q: Why is that?

A: As the Company has consistently explained in its testimony and responses to information requests, the forecasts for sales to large commercial and industrial customers, including standby service customers, were based on econometric techniques, not customer-by-customer projections. (We have attached as Exhibit ___ (JJB/SDL-8) our response to IR No. 264 (PSC-209 Visalli (RAV-40)) which discusses this point in greater detail.) Therefore, accepting for purposes of discussion Staff's position that a line-item-by-line-item comparison of revenues is required for a deferral, the overall level of sales to customers in the large commercial and industrial classes, rather than the level of sales to customers within those classes (such as standby service to generators), is what is significant for purposes of determining whether a loss of revenues from a legal or regulatory change represents a reduction compared to what the Company expected to receive from that class under the Merger Rate Plan rates. In other words, even under Staff's approach, its assertion that any standby service revenues the Company might receive after the Rate Plan took effect would constitute a windfall because they were unaccounted for in the forecast, and so would deferral of the effects of a regulatory change curtailing those revenues, must be tested by comparing forecasted sales to all large commercial and industrial customers with actual sales to those customers.

Q: Did you perform such a comparison?

A: Yes, as part of our response to IR No. 264 (PSC-209 Visalli (RAV-40)), we compared actual and forecast sales to large commercial and industrial customers before and after the Rate Plan took effect. The comparison, included in Exhibit __ (JJB-SDL-8), shows that actual sales to large commercial and industrial customers were less than forecast sales both before and after the Rate Plan (through 2004). Had the regulatory changes limiting the Company's ability to charge for standby service not taken place, standby service sales would only partially have offset the shortfall in sales to the large commercial and industrial classes taken together as a whole. They would not have constituted a windfall such that the impact of the regulatory changes on the Company's revenues should be excluded from Section 1.2.4.3 of the Merger Joint Proposal.

Q: Are you saying that Niagara Mohawk is entitled to defer the impact of the shortfall in sales to large commercial and industrial customers, as compared to the forecast?

A: No. As we have made clear, only the revenue impact of a legal or regulatory change is eligible for deferral under Section 1.2.4.3. We present this comparison only to show that Staff's insistence on a comparison to sales forecast line items does not support its position.

Q: Does your comparison between forecast and actual revenues to large commercial and industrial customers bear on any other argument made in the Staff Panel's responsive testimony?

A: We think so. On page 23 of its responsive testimony, the Staff Panel argues that allowing the deferral of lost station service revenues would cause Niagara Mohawk's electric delivery rates to exceed just and reasonable rates. Mr. Reilly discusses a number of reasons why this is incorrect in his rebuttal testimony. Since the revenues that Niagara Mohawk could have realized from standby service sales but for the regulatory changes we have discussed would only make up for a portion of the shortfall in sales to large commercial and industrial customers, as compared with the sales forecast for this class in the Merger Rate Plan, deferral of these lost revenues cannot cause Niagara Mohawk's rates to exceed the levels contemplated in the Rate Plan.

III. Conclusion

Q: Thank you. I have no further questions at this time.

Rebuttal Testimony of William R. Richer, Steven W. Tasker, and James M. Molloy

Testimony of W. R. Richer,
S. W. Tasker, J. M. Molloy

REBUTTAL TESTIMONY OF
WILLIAM R. RICHER, STEVEN W. TASKER, and
JAMES M. MOLLOY

I. Introduction

Q: Please state your names and business addresses.

A: William R. Richer. My business address and credentials were set forth in my responsive testimony, filed in this proceeding on September 1, 2006.

A: Steven W. Tasker. My business address and credentials were likewise set forth in my responsive testimony, filed in this proceeding on September 1, 2006.

A: James M. Molloy. My business address and credentials were likewise set forth in my responsive testimony, filed in this proceeding on September 1, 2006.

Q: What is the purpose of your testimony here?

A: We are replying to the responsive testimony of Staff witnesses Denise A. Gerbsch and Robert A. Visalli (Staff Panel) regarding pensions and OPEBs. We address three issues: (1) the Company's proposed corrections to capitalized pensions and OPEBs for FYE 3/06; (2) intercompany billings; and (3) Staff's proposed adjustment for employee transfers from Niagara Mohawk to Service Company. A fourth pension and OPEB-related issue, covered earnings, is addressed in the Rebuttal Testimony of Clement E. Nadeau and William F. Dowd. We note that, due to the limited time available, and because we fully described the basis for the deferral in our earlier testimony, we are not responding to every point made in the Staff Panel testimony. Our silence should not be construed as agreement with the arguments presented by the Staff Panel that we do not address. We also note that, in this rebuttal testimony, we will use defined terms and acronyms with the meanings defined in our responsive testimony.

Q: Are you sponsoring any exhibits in support of your rebuttal testimony?
A: Yes. We are sponsoring Exhibits __ (P&O-5), __ (P&O-6), __ (P&O-7), __ (P&O-8), and __ (P&O-9).

Q: Were these exhibits prepared by you or under your supervision?
A: Yes, they were.

Q: Please describe Exhibit__ (P&O-5).

A: Exhibit __ (P&O-5), which consists of 15 pages, is a set of workpapers underlying the Company's calculation of its proposed corrections to pension and OPEB expense for FYE 3/06, which we will describe shortly.

Q: Please describe Exhibit __ (P&O-6).

A: Exhibit __ (P&O-6), which consists of two pages, is the Company's response to a Staff information request designated as IR No. 419 (DAG-42).

Q: Please describe Exhibit __ (P&O-7).

A: Exhibit __ (P&O-7), which consists of one page, is a reconciliation of OPEB expense for FYE 3/06.

Q: Please describe Exhibit __ (P&O-8).

A: Exhibit __ (P&O-8), which consists of two pages, shows the Company's recalculation of intercompany billing revenues using actual pre-ERP data.

Q: Please describe Exhibit __ (P&O-9).

A: Exhibit __ (P&O-9), which consists of one page, shows the Company's calculation of what an adjustment for transfers of employees from Niagara Mohawk to Service Company should be if the Commission rejects the Company's position and agrees with Staff that an adjustment is appropriate.

Q: What does the Staff Panel's responsive testimony say about the Company's proposed corrections to capitalized pensions and OPEBs for FYE 3/06?

A: Staff states (page 37, lines 10-15) that it is not accepting those adjustments on the ground that they are not adequately supported. Staff further states that it requested further support in a meeting on September 7, 2006 (page 37, lines 18-21).

Q: Please explain further the basis for the Company's proposed corrections to capitalized pensions for FYE 3/06.

A: The difference between Staff's and the Company's FYE 3/06 pension expense – $59,360,056 versus $59,124,369, or $235,687 – is the result of a reconciling adjustment made to pension expense originally booked for

February 2006. (We note here that "pension expense" and "OPEB expense" refer to the Company's aggregate costs as provided by its actuary, and not to those portions of pension and OPEB expense that ultimately are charged for accounting purposes to expense and not capital.) Based on the estimate provided by Hewitt, the Company's actuary, the Company had booked $4,946,634 to expense for February 2006. This entry subsequently was adjusted to reflect a $235,425 credit made as a result of the reconciliation of (1) Niagara Mohawk's pension expense balance at 3/31/05 per the Company's General Ledger, and (2) Hewitt's determination of the pension plan's funded status at the same date, or 3/31/05. Exhibit ___ (P&O-5) sets forth the workpapers supporting the Company's corrections to pension expense for FYE 3/06. (A further *de minimus* discrepancy of $262 – $235,687 versus $235,425 – can be attributed to the rounding of pension expense booked.)

Q: Please explain further the basis for the Company's proposed corrections to capitalized OPEBs for FYE 3/06.

A: The difference between Staff's and the Company's FYE 3/06 OPEB expense – $69,794,656 versus $70,497,651, or $702,995 – results from two separate items. The first is a reconciling adjustment to OPEB expense originally booked for February 2006, similar to pension expense as described above. The Hewitt OPEB expense estimate of $5,865,278 booked for February 2006 subsequently was offset by a $114,493 debit to OPEB expense. This debit resulted from the reconciliation of (1) Niagara Mohawk's OPEB expense balance at 3/31/05 per the Company's General Ledger, and (2) Hewitt's determination of the funded status of the Company's OPEB obligations at the same date, or 3/31/05. Exhibit ____ (P&O-5) sets forth the workpapers supporting the Company's corrections to OPEB expense for FYE 3/06.

The second item to account for the difference between the Company's and Staff's calculation of FYE 2006 OPEBs is an error. Hewitt, in its September 2005 and March 2006 letters related to FY 2006 OPEB expense, mistakenly included a $708,742 allocation of a regulatory asset to Service Company; of that total, $588,256 is allocable to electric operations. The Company does not use the regulatory amortization amounts included in Hewitt's expense letters, but rather books regulatory amortization according to the established amortization schedule. This was explained in our response to IR #419, PSC-355, (DAG-42), a copy of which is included as Exhibit ___ (P&O-6). The combination of these two items (plus rounding effects totaling $247) accounts for the $702,995 difference between the Company's and Staff's FY 2006 OPEB expense. This is detailed in Exhibit ____ (P&O-7).

Q: Do you agree with Staff's restated calculation of capitalized pensions and OPEBs for FYE 3/06 (pages 38 – 39)?

A: No. We stand by the corrected calculations we provided in our previous testimony for the reasons stated immediately above.

Q: What does the Staff Panel's responsive testimony say about intercompany billings?

A: After accepting the Company's position on third-party billings, Staff states that it believes the Company agrees, at least in principle, with Staff's proposed adjustments to pre-ERP intercompany billings for pension and OPEBs (pages 50 – 52).

Q: What is the Company's response to Staff's statement?

A: Staff is correct – the Company accepts in principle Staff's proposed adjustments to pre-ERP intercompany billings to account for pension and OPEB expense. Staff indicated in their testimony that they would allow the Company to provide a more precise calculation subject to their review.

The Company has further researched its accounting records, and we have calculated adjustments using actual pre-ERP intercompany revenues. Our recalculated adjustments are shown in Exhibit __ (P&O-8).

Q: What does the Staff Panel's responsive testimony say about Service Company transfers?

A: Staff restates its position that Niagara Mohawk is receiving double recovery of pension and OPEB costs as a result of the transfer of employees from Niagara Mohawk to Service Company. Staff also provides a revised calculation of its proposed adjustments based on the alleged double recovery (pages 52 – 55).

Q: What is Niagara Mohawk's response?

A: For the reasons stated in our previously filed testimony, we believe no adjustment is necessary or appropriate. If, however, the Commission were to agree with Staff and impose adjustments based on employee transfers from Niagara Mohawk to Service Company, we believe Staff's revised calculation of what the adjustments would be is not quite correct. For one, Staff acknowledges that a portion of their proposed adjustment contains a temporary placeholder amount (page 55, lines 7-10). Staff should use the information provided in response to IR #419, PSC-355 (DAG-42), a copy of which is included as Exhibit __ (P&O-6) for the FYE 3/06 proposed OPEBs expense adjustment. Second, Staff's calculation fails to reduce their adjustment for the portion of costs charged to Service Company that would be allocated back to Niagara Mohawk. Exhibit __ (P&O-9) reduces the amount of Staff's proposed adjustment for the items discussed above.

II. <u>Conclusion</u>

Q: Thank you. I have no further questions at this time.

Rebuttal Testimony of Clement E. Nadeau and William F. Dowd

Testimony of
C. E. Nadeau, W. F. Dowd

REBUTTAL TESTIMONY OF CLEMENT E. NADEAU and WILLIAM F. DOWD

I. Introduction

Q: Please state your names and business addresses.

A: Clement E. Nadeau. My business address and credentials were set forth in my responsive testimony, filed in this proceeding on September 1, 2006.

A: William F. Dowd. My business address and credentials were likewise set forth in my responsive testimony, filed in this proceeding on September 1, 2006.

Q: What is the purpose of your testimony here?

A: We are replying to a point raised in the responsive testimony of Staff witnesses Denise A. Gerbsch and Robert A. Visalli (Staff Panel) regarding pensions and OPEBs. We note that, due to the limited time available, and because we fully described the basis for our position in our earlier testimony, we are not responding to every point made in the Staff Panel testimony, and our silence should not be construed as agreement with the arguments presented by the Staff Panel that are not addressed.

Q: In its responsive testimony, the Staff Panel "expand[s] upon the Company panel testimony [i.e., Nadeau and Dowd] concerning the covered earnings change associated with the pension plan . . . ." (page 44, lines 6-9) More particularly, the Staff Panel points out that under the 2004 Union contract the covered earnings level used to calculate pension benefits will not reach the IRS-prescribed level for 20 years (page 47, lines 3-6). Why did National Grid agree to this phase-in period?

A: To avoid a strike by our represented employees in New York. We pushed hard in negotiations to implement quickly the IRS-prescribed covered earnings limit in lieu of the much lower limit we were using to determine pension benefits. However, the Union, perhaps not surprisingly, resisted. In our opinion based on many months spent in negotiations, including a late stage when both sides began to prepare for a strike, the covered earnings compromise embodied in the final Union contract reflects the best achievable outcome on that issue. To have pushed for more would have likely resulted in a strike, an outcome that National Grid believes would not have been in the best interest of our customers, our employees (represented and non-represented alike), or our shareholders.

II. <u>Conclusion</u>

Q: Thank you. I have no further questions at this time.

Rebuttal Testimony of James J. Bonner Jr. and Lee A. Klosowski

Testimony of J. J. Bonner, Jr., L. A. Klosowski

REBUTTAL TESTIMONY OF JAMES J. BONNER JR. and LEE A. KLOSOWSKI

I. Introduction

Q: Please state your names and business addresses.

A: [By Mr. Bonner] My name is James J. Bonner Jr. My business address and credentials were set forth in our responsive testimony, filed in this proceeding on September 1, 2006.

A: [By Mr. Klosowski] My name is Lee A. Klosowski. My business address and credentials, too, were set forth in our responsive testimony, filed in this proceeding on September 1, 2006.

Q: What is the purpose of your rebuttal testimony?

A: We will respond briefly to certain assertions regarding the Customer Service Backout Credits deferral presented in the testimony of Staff witnesses Denise A. Gerbsch and Robert A. Visalli (the "Staff Panel) in their Responsive Testimony filed on September 19, 2006. We note that, due to the limited time available, and because we fully described the basis for the deferral in our earlier testimony, we are not responding to every point made in the Staff Panel testimony. Our silence should not be construed as agreement with the arguments presented by the Staff Panel that we do not address. We also note that, in this rebuttal testimony, we will use defined terms and acronyms with the meanings defined in our responsive testimony.

Q: Do you sponsor any exhibits?

A: Yes, we have two exhibits. Exhibit ____(JJB/LAK-1) is a redacted copy of the summary pages of the Company's Response to Information Request ("IR") No. 422 (PSC-358 Visalli (RAV-131)) and Exhibit _____(JJB/LAK-2) is a corrected calculation of Staff's adjustment for Customer Service Backout Credits to Direct Customers, including redacted responses to IRs from which the data in the calculation are drawn.

II. <u>Response to Assertions Regarding Customer Service Backout Credits</u>

Q: Do you have any comments on the Staff Panel's assertion on page 95, lines 20-22, that your earlier testimony did not address the Staff Panel's "basic underlying reason for [its] proposed disallowance?"

A: Yes. This assertion is unfounded. In our earlier testimony, we noted explicitly (on page 9, lines 1-5, among other places) Staff's contention that the Company violated its tariff by providing Customer Service Backout Credits to Direct Customers who purchase electricity supplies themselves in addition to those who purchase their electricity needs through a third-party Energy Service Company ("ESCo"). We then stated directly, on page 12, line 17, through page 13, line 2, that we disagreed with Staff's interpretation of Niagara Mohawk's tariff, and proceeded to explain the bases of our disagreement over approximately seven pages of testimony. Accordingly, Staff's assertion that we did not address the basic rationale underlying its proposed adjustment is based on an obvious misreading of our earlier testimony.

Q: What did you identify as the bases of your disagreement with Staff?

A: We identified seven reasons why Staff's position was based on an incorrect interpretation of Niagara Mohawk's tariff. We first explained that each Direct Customer functions as its own ESCo and, therefore, the language of Rule 42 of the tariff making Customer Service Backout Credits available to any customer taking service from an ESCo encompasses Direct Customers (page 13, lines 5-15). That is, under Niagara Mohawk's tariff, an ESCo is any entity that supplies electric supply service, including a Direct Customer that supplies electric supply service to itself. We next explained that our interpretation, but not Staff's, is consistent with the Merger Joint Proposal, which recognizes that Direct Customers, as well as customers served by a third-party ESCo, are eligible for Customer Service Backout Credits (page 13, line 20 – page 14, line 8).

Third, we explained that our interpretation, but not Staff's, is also consistent with Commission rules and orders in which the term "ESCo" is used to refer both to ESCos serving third-party customers and Direct Customers (page 14, line 13 – page 15, line 3). Fourth, we explained that our interpretation, but not Staff's, is consistent with the purpose of giving Customer Service Backout Credits to customers who make alternative arrangements to procure energy (page 15, line 7 – page 16, line 2) and with Commission policy set forth in Case 00-M-0504.[1] Fifth, we explained that our interpretation, but not Staff's, is consistent with Staff's recommendation to the Commission in 2001 to approve the tariff language that it would now interpret to deny Customer Service Backout Credits to Direct Customers (page 18, lines 5-14). Sixth, we explained that our interpretation, but not Staff's is consistent with the circumstances surrounding the proposal and adoption of that tariff language, which demonstrate the common intention to continue to provide Customer Service Backout Credits to Direct Customers and to customers taking service from third-party ESCos (page 18, line 15 – page 19, line 11). Seventh and finally, we noted that Staff did not advance its current

[1] See Case 01-M-00504, *Proceeding on Motion of the Commission Regarding Provider of Last Resort Responsibilities, the Role of Utilities in Competitive Energy Markets, and Fostering the Development of Retail Competitive Opportunities - Unbundling Track*,. STATEMENT OF POLICY ON UNBUNDLING AND ORDER DIRECTING TARIFF FILINGS, (Issued and Effective August 25, 2004).

interpretation of the Company's tariff during the discussion that led to the 2003 Memorandum of Agreement ("MOA"), even though the language in Rule 42 on which Staff relies to deny the deferral of post-Merger Rate Plan Customer Service Backout Credits was already in effect (page 19, line 16, – page 20, line 20; also, page 10, line 10 – page 11, line 10).

Q: Does the Staff Panel address the reasons you gave for disagreeing with their interpretation of the Company's tariff to deny Customer Service Backout Credits to Direct Customers?

A: Not in any meaningful way. Staff does not contradict or even address any of the first six reasons we gave for our interpretation of Niagara Mohawk's tariff to make Customer Service Backout Credits available to Direct Customers, as well as customers served by third-party ESCos. It does address the seventh reason by offering its claims that the deferral associated with the PowerChoice period "is insignificant" and, in any case, Staff just missed the issue when it was auditing the Company's deferral balances prior to the MOA (see page 94, lines 9-18). Staff's admission of its oversight, however, provides no affirmative support for its strained interpretation of the tariff to reach a result that obviously was not intended either by the Company or by Staff, and is inconsistent with Commission policy. It is also worth noting that the deferrals for Customer Service

Backout Credits to Direct Customers during the PowerChoice period constituted about $1.4 million, or over 13% of the total deferrals for Customer Service Backout Credits during this period. This is shown on Exhibit __ (JJB/LAK-1).

Q: Do you have any comments about the Staff Panel's assertion on page 97, lines 22-24, that you admitted in your earlier testimony that Niagara Mohawk is providing Customer Service Backout Credits to Direct Customers in violation of the language in its tariff?

A: Yes. As we have stated, we spent about eight pages of our earlier testimony stating that the tariff's reference to the provision of Customer Service Backout Credits to customers served by ESCos encompasses Direct Customers acting as their own ESCos and explaining why that is so. We did not "admit" that providing the credits to Direct Customers violates the tariff either there, or in the portion of our testimony cited by Staff (page 20, line 7 – page 21, line 11). In that passage, we explained why we had not submitted a tariff filing to modify the language once Staff notified the Company of its new interpretation of that language. Nowhere in that explanation did we express agreement with Staff's new interpretation.

Similarly, in the IR response also cited by Staff, we explained that the tariff language was broad enough to apply to "Direct Customers [that] are basically acting as their own 'ESCo,'" and is appropriately interpreted to give effect to its clear intention: "to provide a credit to customers on their service bills if they elect to take Electricity Supply Service ("ESS") from an alternative energy supplier, which includes both Energy Service Companies ("ESCos") and Direct Customers of the NYISO." We did not admit that applying the tariff to provide credits to Direct Customers was improper, though we acknowledged that the issue could be clarified through a housekeeping filing. Such a clarification filing, if made and adopted, would in no way affect the number, type or identity of the customers that receive the Customer Service Backout Credits from the population that receives those credits today. In our earlier testimony we explained why we concluded, in light of this proceeding, why submitting such a filing seemed like an unnecessary use of resources.

Q: Given your interpretation of the tariff, which concludes that the language authorizes direct service customers to receive the Customer Service Backout Credit, do you agree with the Staff's contentions about retroactive ratemaking?

A: No. It is Staff, who is suggesting that we implement a new construction of the tariff retroactively to deny customers the benefit of a credit that is consistent with the Commission's policy, authorized under Niagara Mohawk's tariff, and has been consistently applied by the Company to Direct Customers since the opening of retail markets in New York, without prior objection from Staff. Niagara Mohawk is not proposing to apply a new interpretation of its tariff retroactively, Staff is suggesting that the Commission retroactively adopt the new reading, which as we have indicated is inconsistent with the Commission's policy and Niagara Mohawk's past practice.

Given this background, Staff's discussion (pages 96-99) of limitations on backbilling under the Commission's regulations have no application to the case, and its suggestion of a penalty at page 99 is totally unwarranted.

Q: Do you have any further comments on the issue of Customer Service Backout Credits?

A: Yes. On page 5 of its responsive testimony, the Staff Panel describes the correction of an error in how it calculated its Customer Service Backout Credit adjustment, indicating a reduction in its proposed disallowance. In further reviewing Staff's adjustment, we determined that Staff used the wrong basis for calculating its adjustment ($9.2 million instead of the correct basis of $8.9 million). Although the Company does not believe any disallowance is appropriate, using the corrected basis for calculating the adjustment (assuming, for the sake of analysis, that any adjustment is warranted), would result in a proposed Staff disallowance of $6,692,123 instead of $6,919,675 as originally proposed. The calculation, as well as redacted IR responses from which the data used in the calculation were drawn, are provided as Exhibit __(JJB/LAK-2).

III. Conclusion

Q: Thank you. I have no further questions at this time.

Rebuttal Testimony of Michael J. Kelleher, Steven W. Tasker and James J. Fletcher

Testimony of
M. J. Kelleher, S. W.
Tasker, J. J. Fletcher

REBUTTAL TESTIMONY OF MICHAEL J. KELLEHER, STEVEN W. TASKER and JAMES J. FLETCHER

I. Introduction

Q: Please state your name and business address for the record.

A: [By Mr. Kelleher] My name is Michael J. Kelleher. My business address and credentials were set forth in our responsive testimony, filed in this proceeding on September 1, 2006.

A: [By Mr. Tasker] My name is Steven W. Tasker. My business address and credentials were set forth in our responsive testimony, filed in this proceeding on September 1, 2006.

A: [By Mr. Fletcher] My name is James J. Fletcher. My business address and credentials were set forth in our responsive testimony, filed in this proceeding on September 1, 2006.

Q: What is the purpose of your rebuttal testimony?

A: We respond briefly to certain assertions by Staff witnesses Denise A. Gerbsch and Robert A. Visalli (the "Staff Panel") in their Responsive Testimony filed September 19, 2006. Due to time constraints, and because our September 1, 2006 testimony set forth our principal positions with respect to these issues, we do not respond to every point made in the

Staff Panel testimony. To the extent we do not expressly respond to every point raised in the Staff Panel's Responsive Testimony, such silence should not be construed as agreement with the arguments presented by the Staff Panel that are not addressed. We also note that, in this rebuttal testimony, we use defined terms and acronyms with the meanings defined in our September 1 testimony.

Q: What exhibits are you sponsoring in support of your rebuttal testimony?

A: We are sponsoring one exhibit. Exhibit __ (GSC-11) presents a summary of the positions of Staff and the Company on net deferrals at issue in this proceeding as of December 31, 2007. The exhibit incorporates and builds upon the information in Staff Exhibit __ (SP-1A).

II. <u>Response to Staff Panel Assertions</u>

Q: What issues do you address in your testimony?

A: We address four principal issues: (1) Staff Panel's testimony regarding revenues for services provided to Constellation; (2) Staff Panel's assertions regarding the Nine Mile Point I sale price reduction; (3) Staff's argument regarding the amortization of an additional $11.2 million of nuclear stranded cost related to the sale of the Nine Mile Point plant; and

(4) Staff's argument regarding the loss recorded by the Company in connection with the disposition of the leasehold improvements for the Dey's Building.

A. Revenues for Services to Constellation Nuclear

Q: Please respond to Staff's assertion (page 57, lines 4-8) that "ratepayers already compensated the Company in base rate allowances for the costs (base labor, fringe benefits, etc.) to provide service to Constellation."

A: Staff's assertion is incorrect. The Merger Joint Proposal and the Merger Rate Plan established under it were predicated on the assumption, which ultimately proved correct, that Niagara Mohawk would divest its interests in Nine Mile I and Nine Mile II prior to closing of the merger of National Grid and Niagara Mohawk. As a result, Niagara Mohawk's costs of operating the nuclear plants are not reflected in the Merger Rate Plan base rates. The reduction of delivery rates by $152 million in the Merger Rate Plan was based in part on the elimination of those costs from base rates. Therefore, the costs incurred to provide services to Constellation were incremental to the costs reflected in base rate allowances. If any post-Merger Rate Plan revenues received from Constellation are to be credited to customers, the credit should be based only on net revenues (gross revenues less incremental costs).

Q: Do you believe customers are entitled to any revenues received from Constellation?

A: Yes, as mentioned in our testimony of September 1, 2006, we believe crediting 100 percent of the pre-Merger Rate Plan revenues to the deferral account is appropriate. Before the Merger Rate Plan took effect, an allowance for the costs of providing the service was indeed included in the Company's rates.

With respect to the post-Merger Rate Plan period, we explained that no provision of the Merger Rate Plan specifically provides for the deferral of the revenues from Constellation, but these revenues could be viewed as revenues received for "incidental services" that are subject to Section 1.2.4.18 of the Merger Rate Plan, with the result that 50% of the net revenues could be credited to customers. The result would be that under Section 1.2.4.18, an amount of $387,287 (50% of the net revenues of $774,574) would be credited to customers.

Q: What is the Staff Panel's position on the applicability of Section 1.2.4.18 to the revenues received for services provided to Constellation?

A: The Staff Panel disagrees that Section 1.2.4.18 applies to the revenues received for providing services to Constellation, and instead argues that Section 1.2.4.18 was intended to encompass only a more limited class of services provided to customers (page 59, lines 13-23). As we said before, we agree that no specific provision of the Merger Rate Plan covers the revenues received from Constellation, and that Section 1.2.4.18 provided the "closest fit" of any of the specific provisions in the Merger Rate Plan for crediting the deferral account with any of the Constellation revenue. Therefore, to the extent the Commission concludes that revenues received for transition services provided to Constellation during the Merger Rate Plan period should be credited to customers, such credit should be based on Section 1.2.4.18 of the Merger Rate Plan, which sets forth the provision that is most arguably applicable to such net revenues. Otherwise, to the extent Section 1.2.4.18 is deemed not applicable as Staff contends, then no sharing of such net revenues should be provided.

B. Nine Mile Point I Price Reduction

Q: What does Staff say about the $7.5 million price reduction for Nine Mile Point I?

A: Staff contends that Niagara Mohawk should have invoked the dispute resolution clause of the Asset Purchase Agreement (APA) and proceeded to closing, after which arbitration would have produced a resolution of the dispute over Constellation's proposed last-minute price adjustment.

Q: What is your response to Staff's contention?

A: Staff's version of what theoretically might have transpired is wholly unrealistic. Constellation, as the purchaser, was only agreeing to close the transaction with a downward price adjustment of $13.2 million, and the agreement of Niagara Mohawk to pay for additional, uncapped damages, if there were any extended outages or other operational problems related to this issue. Had Niagara Mohawk done as Staff suggests, and attempted to proceed to closing while invoking the dispute resolution provisions of the APA, Niagara Mohawk would have faced closing with a price adjusted downward by $13.2 million and an uncapped future risk associated with the nuclear plant operations. Or Niagara Mohawk could have not agreed to close the transaction and faced the cost and risk of trying to find another purchaser ready to execute the necessary documents and to issue payment for several hundred million dollars. Instead of a successful sale, followed by closing of the merger with National Grid and implementation of the Merger Rate Plan, Niagara Mohawk would have been left with a claim for breach of contract against Constellation Nuclear, enormous uncertainty, and likely years of litigation. There is no basis for the notion that closing subject to arbitration over purchase price adjustments was a practical option.

C. Nuclear Stranded Cost Amortization

Q: What position does the Staff Panel take with respect to the nuclear stranded cost amortization?

A: The Staff Panel continues to argue that the nuclear stranded costs written off by the Company should be increased by $11.2 million, and the stranded costs included in the deferral account reduced by the same amount, because, in the Staff Panel's view, this adjustment is necessary to give effect to the delay in the Effective Date of the Merger Rate Plan to February 1, 2002 in accordance with the terms of the Merger Joint Proposal. In our earlier testimony (beginning on page 15), we pointed out that Staff's position would give customers a double credit for the delay.

The Staff Panel now agrees that its position "results in a double credit in the ratepayers favor," but argues that this result is appropriate and required by the terms of the Merger Joint Proposal (page 62, lines 6-22).

Q: How does the Staff Panel attempt to justify its interpretation of the Merger Joint Proposal to entitle customers to a double credit for the delayed effective date?

A: The only justification the Staff Panel presents is an argument that the double credit it seeks is counter-balanced by its discovery of "unwritten double-counts" that charge customers too much in the Merger Rate Plan base rates for deferrable storm restoration costs (pages 63 – 65). Thus, Staff Panel effectively concedes that there is no basis to believe the parties intended the Merger Joint Proposal to be interpreted to give customers duplicative credits for a delayed effective date, but contends that this shortcoming can be ignored because it so happens that adopting Staff's interpretation would compensate for errors that Staff made in negotiating another provision of the Merger Joint Proposal.

Q: Do you agree with the Staff Panel's attempt to link the nuclear amortization and storm restoration cost deferral issues in this way?

A: No. As Staff says several times in its testimony, "Two wrongs do not make a right" (pages 21, 94 – 95). The Commission should interpret and apply **all** provisions of the Merger Joint Proposal in accordance with their terms to give effect to the parties' intent. This is the proper way to preserve the "delicately balanced settlement" that Staff correctly states is embodied in the Merger Joint Proposal (page 66). In contrast, justifying an unintended interpretation of one deferral provision by reference to purported "unwritten double-counts" simply shifts the balance away from the settlement negotiated by the parties.

Q: Is there any validity to Staff's claim that there are "unwritten double-counts" in the Company's favor that justify a double credit for customers on the nuclear amortization issue?

A: No. Both of Staff's claimed "double-counts" amount to concerns that the budgeted allowance for storm restoration costs used to set the Merger Joint Proposal rates was incorrect. Staff recognizes that it would be inappropriate to reopen the determination of the Merger Joint Proposal rates to correct these purported errors, but it seeks to achieve the same result by using them to justify an unsupported interpretation of the Merger Joint Proposal to produce a double credit on an unrelated issue. But this indirect attempt to reopen the negotiated Merger Joint Proposal rates is every bit as inappropriate as a direct attempt would be. Under Staff's logic, Niagara Mohawk could rely on overspending in areas that are not subject to deferral to justify strained readings of Merger Rate Plan provisions to allow it to increase deferrals of unrelated costs. This would obviously be unsupportable, and the Company has not done so. The Staff Panel's attempt to use this approach on the nuclear amortization issue has no better basis.

Q: Staff also claims that the Company's debiting of the $11.2 million nuclear amortization to expense reflects an acknowledgement on its part that the amortization should be charged to the Company's shareholders under the Nuclear Settlement. How do you respond?

A: The issue is who is entitled to receive the benefit of the $11.2 million of nuclear amortization for January 2002, not how to do so from an accounting standpoint. Focusing, as Staff does, on the accounting mechanics, rather than the requirements of the Merger Joint Proposal and the Nuclear Settlement, only confuses the issue. Until the Effective Date of the Merger Joint Proposal, the Company was obligated to follow the Nuclear Settlement. Nuclear amortization was charged to shareholders in

January 2002, in consideration of the revenues being credited to shareholders under Power Choice in January 2002. The Merger Rate Plan Delay Credit established a different amount of revenues to be credited to shareholders for January 2002 and the amount of stranded cost amortization for that month should be based only on the Merger Joint Proposal.

Q: Staff asserts "[t]he nuclear amortization credit was to remain in effect until 'rates were reset'" and points to the fact that rates were reset "on February 1, 2002, the Effective Date of the Merger Joint Proposal" (page 62, lines 19-22) as a basis for their adjustment. Do you agree?

A: No. Staff's position fails to recognize that the Merger Delay Credit effectively reset customers' rates with respect to the treatment of nuclear stranded costs as of January 1, 2002. The Merger Delay Credit gave customers the economic value of the reduction in prices to a new revenue requirement, starting January 1, 2002, based on a write-off of nuclear stranded costs and a new level of amortization of stranded costs during the 10-year term of the Merger Rate Plan. The Merger Delay Credit is not unlike other "make whole" provisions approved by the Commission to give effect to a delay in new rates being implemented beyond the start of a rate year. Such provisions resolve the "seams" issues that arise between the terms of two rate plans; here between Power Choice/Nuclear Settlement and Merger Rate Plan/Nuclear Settlement.

D. Loss Recorded in Connection with Leasehold Improvements

Q: At pages 74-78 of its Responsive Testimony, the Staff Panel takes issue with your September 1, 2006 testimony regarding the loss recorded by the Company in connection with the disposition of the leasehold improvements for the Dey's Building. Could you please respond?

A: Yes. This issues hinges on the interpretation of the Commission's order in Case 03-M-1374 (the O'Neill Order) which directed the Company "to provide for a 50/50 sharing of any losses from future transfers or leases of any part of its works or systems, with a book value of $3,000,000 or less." Staff contends that this language applies only to transfers or leases of Company-owned facilities, not leases the Company has on facilities owned by an outside enterprise such as the arrangement at the Dey's Building.

Q: Please continue.

A: Though we were the lessee, not the owner, of Dey's Building, we considered the leasehold improvements on the Dey's Building to be part of our works or systems. Leasehold improvements are alterations, renovations and repairs to leased facilities that increase the value of the property, make it more useful, or lengthen its life. These improvements are accounted for as an asset on the books of the Company and are depreciated like other company-owned capital assets. We believe that our position of sharing the loss 50/50 per the O'Neill Order is justified based on our view that for accounting purposes, the unamortized cost of leasehold improvements is an asset on our books just as the unamortized cost of buildings (such as O'Neill, Buffalo Electric, etc.) were assets on our books. The leasehold improvements are "owned" by the lessee until the expiration of the lease, at which time, ownership is transferred to the lessor. We believe that the loss resulting from the transfer of the leasehold improvements to the lessor at the expiration of the lease, which requires us to write-off the unamortized value of the asset on our books, is required under the O'Neill Order to be shared 50/50 with customers.

III. Conclusion

Q: Thank you. I have no further questions at this time.

Rebuttal Testimony of Scott D. Leuthauser

Testimony of
S. D. Leuthauser

REBUTTAL TESTIMONY OF SCOTT D. LEUTHAUSER

I. Introduction

Q: Please state your name and business address for the record.

A: My name is Scott D. Leuthauser. My business address and credentials were set forth in my responsive testimony, filed in this proceeding on September 1, 2006.

Q: What is the purpose of your testimony?

A: I will respond briefly to certain assertions regarding the deferral associated with the Company's efforts to implement the new elevated voltage testing and facilities inspection programs mandated by the Commission's Safety Orders presented by Staff witnesses Denise A. Gerbsch and Robert A. Visalli (the "Staff Panel") in their Responsive Testimony filed on September 19, 2006. I note that, due to the limited time available, and because I fully described the basis for the deferral in our earlier testimony, I am not responding to every point made in the Staff Panel testimony. My silence should not be construed as agreement with the arguments presented by the Staff Panel that are not addressed. I also note that, in this rebuttal testimony, I will use defined terms and acronyms with the meanings defined in my responsive testimony.

Q: What exhibits are you sponsoring in support of your testimony?

A: I am sponsoring Exhibit__(SDL-3) illustrating that the response to IR #342, PSC-292 Gerbsch (DAG-31) Attachment 4 contains a list of names and titles of the employees who are completing the work to comply with the Safety Order, and Exhibit__(SDL-4) illustrating that in the response to IR #95, PSC-90 Gerbsch (DAG-3) the Company provided the names of six employees who were re-hired after being laid off. Exhibit__ (SDL-5) is the letter agreement provided to Staff as referenced in IR #94, PSC-89 Gerbsch (DAG-3) between the Company and the IBEW for the re-hire of such employees. Exhibit__ (SDL-6) lists eight underground splicers hired to fortify the department to complete inspections. All of these exhibits were prepared by me or under my supervision and direction.

Q: Please describe generally what assertions of the Staff Panel concerning elevated voltage and facilities inspection you will address.

A: First, I will address the Staff Panel's assertion that the Company is not basing its deferral for the incremental costs of compliance with the Safety Orders on actual costs (page 85, line 2). Second, I will address the Staff Panel's claim that there is no evidence that additional employees are being hired to perform incremental activities required to comply with the Safety Orders (page 81, lines 11-12). Third, I will address the Staff Panel's assertion that none of the employees hired to perform new work required by the Safety Orders is incremental because the Rate Plan anticipated that an additional 231 employees would be hired in the asset management and field operations areas (page 82 line 7 – page 83 line 14). Fourth, I will address the Staff Panel's contention that non-incremental transportation costs are included in the Stray Voltage deferral (page 84, lines 14 -18).

II. Response to Staff Assertions

Q: Turning to the first issue, do you have any comments on the Staff Panel's testimony on page 85, lines 2-10 regarding the basis of the deferral costs of compliance with the Safety Orders?

A: Yes. The Staff Panel suggests that the proposed deferral for the costs of compliance with the Safety Orders is somehow invalid because it is based on cost projections. It is my understanding that the Company is required to forecast the costs eligible for deferral for the period beginning July 1, 2005. We have done so. In developing the forecast, the Company used data known at the time of development regarding actual costs to calculate a projection of costs. The Company will track, in the deferral account for the Safety Order all actual costs (debits) and revenues received through rates (credits), making the forecast somewhat irrelevant. The Commission-approved incremental costs will be tracked against the Commission-approved incremental revenues added into rates through this CTC Reset Proceeding.

Q: Regarding the second issue, is there evidence that the Company hired or rehired new employees to effectuate the Safety Orders?

A: Yes. In my previous testimony, I stated that the Company posted and hired employees, and rehired employees that had been laid off to undertake new activities required to comply with the Safety Orders. To support this statement, I have attached as Exhibit __ (SDL-3) a list of names and titles of employees who are completing the work to comply with the Safety Order (this information was previously provided to Staff in response to IR #348, PSC-292 Gerbsch (DAG-31), as Attachment 4 to the Company's response). The names of the six employees who were re-hired after having been laid off are listed on Exhibit __ (SDL-4) (previously provided to Staff in response to IR #95, PSC-90 Gerbsch (DAG-3)). Additionally, Exhibit __ (SDL-5) is the letter agreement between the Company and the IBEW for the re-hire of such employees (previously provided to Staff and referenced in response to IR #94, PSC-89 Gerbsch (DAG-3)). Not only are these employees incremental, in the sense that they would not have been re-hired were it not for the new requirements imposed by the Safety Orders, but the work they perform is incremental in the same sense.

In addition, as I explained in my previous testimony, the Company posted and hired eight underground cable splicers to meet new requirements of the Safety Orders. All of these new positions were filled by individuals previously employed by Niagara Mohawk doing other jobs. A listing of these individuals in included as Exhibit __ (SDL-6) to this testimony. In most cases their previous positions were backfilled. Whether or not this is the case does not matter, though, since we have calculated the incremental costs to comply with the Safety Order not by tracking FTEs, but rather by tracking the costs of completing the incremental activities, i.e., the work the Company would not otherwise perform but for the Safety Order. The compliance with the Safety Order did not displace any work done before it was issued, so whether or not we replaced employees re-deployed from other departments to do that work does not affect the incremental nature of their new duties.

Q: Does the fact that the Merger Rate Plan rates anticipated the addition of new positions for the asset management and field operations functions mean that Niagara Mohawk is not incurring incremental costs for the employees hired to undertake projects required to comply with the Safety Orders?

A: No. The Merger Rate Plan recognized that the Company would have to hire additional employees, filling open positions, to perform the work required to meet the Company's obligations over the course of the Rate Plan period, based on what was known at the time. The 231 employee positions cited by Staff reflect a negotiated number that the parties agreed was appropriate based on the regulatory requirements that existed at the time; it did not incorporate an allowance for the employees that might be required to meet new regulatory obligations. As stated in reference to the 231 positions in Exhibit __ (SP-10), page 32, "The filling of the open positions is in support of the 2001 work plan developed by the Asset Management. As a result of the open positions, the Company is able to reflect an overall lower overtime level than was experienced in 2000." It simply is not the case that 231 additional positions were embedded in delivery rates to perform unknown future work, as Staff suggests. To the contrary, in aggregate, the Merger Rate Plan reduced Niagara Mohawk's Electricity Delivery Rates by $159.8 million or 8.2 percent per year relative to then-effective Electricity Delivery Rates and 5.1% overall.

As I explained in my previous testimony, the stray voltage testing and inspection programs required to comply with the Safety Orders are new programs that the Company has implemented to meet new requirements. Neither these requirements nor the employees required to satisfy them were contemplated when the Merger Rate Plan was agreed upon and approved, nor could they have been. Since the tasks that the employee positions contemplated in the Rate Plan were intended to perform have not been eliminated, treating the positions required to perform the work to meet the new Safety Program requirements as included in the positions allowed in the Rate Plan would leave the Company shorthanded to meet all of its obligations, including the new obligations imposed by the Safety Orders.

Q: Does the deferral for compliance with Safety Order requirements include non-incremental transportation costs?

A: No. The Staff Panel does not explain why it believes the transportation costs are not incremental, but in their initial testimony they cross-reference the storm restoration cost deferral account method. In my previous testimony regarding inclusion of labor overheads in the deferral for stray voltage requirements (starting at page 11, line 17), I explained why Staff's analogy between the costs of supporting storm restoration work and the stray voltage program is invalid. In order to perform incremental stray voltage work, the Company must incur incremental transportation costs. It is not the case that transportation resources normally dedicated to (and paid by) another function are temporarily borrowed to perform stray voltage testing and inspection activities. Rather, vehicles are dedicated to support this activity. Those vehicles and the associated costs are incremental, as are the personnel who perform the new activities. Because these employee expenses are incremental, the associated transportation is also incremental. Unlike employees working overtime on storm response on a temporary basis, assignment of an employee's time to the incremental inspection and stray voltage testing programs is a regular (albeit new) assignment. The employees supporting storm response are on the property regardless of the occurrence of storms, i.e., they are here to work daily on the system infrastructure. Employees performing incremental inspection and testing activities do such work as a regular part of their jobs, and not as a temporary or emergency activity to respond to a storm. Since work on incremental inspections and stray voltage testing is regular work, clearly distinguishable from temporary overtime to respond to a storm emergency, transportation associated with incremental inspection and stray voltage testing activities should be recoverable.

III. Conclusion

Q: Thank you. I have no further questions at this time.

Rebuttal Testimony of Patrick M. Pensabene

Testimony of
P. M. Pensabene

REBUTTAL TESTIMONY OF PATRICK M. PENSABENE

I. Introduction

Q: Please state your name and business address for the record.

A: My name is Patrick M. Pensabene. My business address and credentials were set forth in our responsive testimony, filed in this proceeding on September 1, 2006.

Q: What is the purpose of your rebuttal testimony?

A: I respond briefly to certain points made by Staff witnesses Denise A. Gerbsch and Robert A. Visalli (the "Staff Panel") in their Responsive Testimony filed September 19, 2006. Due to time constraints, and because my September 1, 2006 testimony set forth the Company's principal positions with respect to these issues, I do not respond to every point made in the Staff Panel testimony. To the extent I do not expressly respond to every point raised in the Staff Panel's Responsive Testimony, such silence should not be construed as agreement with the arguments presented by the Staff Panel that are not addressed.

Q: What exhibits are you sponsoring in support of your rebuttal testimony?

A: Exhibit ___ (PMP-9)

II. Response to Staff Panel Assertions

Q: What issues do you address in your testimony?

A: I address the following issues: (1) Staff Panel's claim at page 33 of its Responsive Testimony that the Company provided no records to support the costs it incurred on January 31, 2002 in connection with restoring service to customers that day; (2) the Staff Panel's assertion that the differential cost of customer restorations on January 31, 2002 and after January 31, 2002 is somehow unreasonable; and (3) the Staff Panel's arguments relating to the cost of insurance claims.

Q: Please address the Staff Panel assertion that the Company did not provide support for the costs it incurred on January 31, 2002 in restoring service to customers that day.

A: In IRs RAV-45 (#269) and RAV-93 (#342), the Company did in fact provide the Staff with support for costs it incurred restoring service January 31, 2002. As indicated in those IR responses, the Company restored service to a total of 31,020 customers, at an estimated cost of $85,890. A copy of IRs RAV-45 (#269) and RAV-93 (#342) were included with my September 1, 2006 testimony as Exhibit __ (PMP- 1) and Exhibit __ (PMP – 2), respectively.

Q: Before addressing these issues, are there any comments you would like to make?

A: Yes. As I discussed in pages 5-12 of my September 1, 2006 testimony, the Company has not proposed an apportionment of the costs of Storm #55645. I believe the Company properly booked the costs to the deferral account, and no adjustment to apportion the incremental costs of Storm #55645 is required. Nevertheless, in my testimony I did describe a methodology the Company believes would be reasonable if the Commission determined that such an apportionment was appropriate.

Q: Could you respond to the Staff Panel's view that the differential between the average cost to restore the initially restored customers on January 31, 2002 and the average cost to restore customers after that date is not reasonable?

A: As described on page 14 of my initial testimony filed September 1, 2006, I agree that the average cost to restore the initially restored customers is less than later restored customers. This should not be surprising, since in responding to a major storm, first priority is given to addressing immediate safety hazards and then making repairs to main transmission facilities including towers, poles and high-voltage wires that may restore power to thousands of customers. Attention then turns to restoring service to primary distribution facilities, then secondary facilities, and finally individual transformers or service lines serving small numbers of customers. (This general procedure is described in the Company's "Storm Central" web-link, located at: www.nationalgridus.com/niagaramohawk/storm/recover_restoring.asp). Thus, normal procedure in storm restoration operations is expected to yield significant differentials in the average cost to restore the first customers compared to the last customers. Staff doesn't disagree with this proposition. Nevertheless, and with no further explanation, Staff suggests that because the differential average cost per customer to restore service to customers interrupted on January 31, 2002 is so much less for service restored on January 31 compared to service restored after January 31, the allocation methodology deemed most appropriate by the Company is somehow unreasonable.

First, Staff points to no factual basis for its conclusion that the differential is objectively unreasonable (pages 33-34). As shown on Attachment 3 in Exhibit ___ (PMP-2), fewer than 1,800 hours of labor (approximately 1,400 hours of overtime) were devoted to storm restoration on January 31. The vast majority of the customers whose service was restored on January 31 were located in the Western Division as shown on Attachment 2 in Exhibit ___ (PMP-1). By focusing its initial efforts on repairing damage in this area, the Company was able to deploy its personnel efficiently to restore service to large numbers of customers quickly, with relatively low incremental costs. In contrast, as detailed in the report included in Exhibit __ (PMP-1), the widespread damage caused by the portion of the storm occurring on February 1 required repairs throughout the system, many of which restored service only to small numbers of customers. There is no dispute that the average per customer cost to restore service to the first group of customers in a storm event is much lower than the average cost to restore service to later-restored customers. Staff offers nothing to counter this and no basis for its conclusion that the differential is otherwise unreasonable. More importantly, however, there is no reason to conclude that even a large restoration cost differential means the allocation methodology is unreasonable.

Q: Please continue.

A: As I described in my initial testimony, the allocation methodology I identified would produce an allocation result much more representative of what other, separately developed information suggests is a reasonable apportionment of storm-related costs than the methodology proposed by Staff. Given that the methodology I describe in my September 1, 2006 testimony produces a result which aligns with this other information, and that there is no basis for finding that a large restoration cost differential between the first and last customers restored leads to an inappropriate result, Staff provides no sound basis for rejecting the allocation method identified by the Company as the most appropriate. Although the Company believes its initial accounting for the costs of Storm #55645 was appropriate, to the extent the Commission determines that an allocation of those costs between January 31 and the period after January 31 is appropriate, the allocation methodology identified by the Company is a reasonable one, and is much more reasonable than the methodology proposed by the Staff Panel.

Q: Please describe the Company's response to the Staff Panel's argument relating to recovery of insurance claim costs.

A: Frankly, I am not sure I completely follow Staff's argument (which is found on pages 35-36 of its Responsive Testimony). However, to the extent Staff contends that the Company conceded that these insurance claims were non-incremental, that is incorrect. As noted in response to IR RAV-130 (#405), the insurance claims of which Staff complains include damage to customers' property directly resulting from major storm restoration. Such costs are not provided for in base rates, and have traditionally been treated as incremental storm costs. See response to IR RAV-130 (#405), attached as Exhibit __ (PMP-9). Staff's suggestion to the contrary is wrong.

III. Conclusion

Q: Thank you. I have no further questions at this time.

Testimony of
J. M. Molloy, W. R. Richer

Testimony of James M. Molloy and William R. Richer

REBUTTAL TESTIMONY OF JAMES M. MOLLOY and WILLIAM R. RICHER

I. Introduction

Q: Please state your name and business address for the record.

A: [By Mr. Molloy] My name is James M. Molloy. My business address and credentials were set forth in our responsive testimony, filed in this proceeding on September 1, 2006.

A: [By Mr. Richer] My name is William R. Richer. My business address and credentials were set forth in our responsive testimony, filed in this proceeding on September 1, 2006.

Q: What is the purpose of your rebuttal testimony?

A: We respond briefly to certain assertions by Staff witnesses Denise A. Gerbsch and Robert A. Visalli (the "Staff Panel"), and by Staff witnesses Patrick Piscitelli and Mr. Visalli (the "SGWP"), in their Responsive Testimony filed September 19, 2006. Because our September 1, 2006 testimony set forth our principal positions with respect to these issues, we do not respond to every point made in the Staff Panel and SGWP testimony. To the extent we do not expressly respond to every point raised in the Responsive Testimony of the Staff Panel and the SGWP, such silence should not be construed as agreement with the arguments presented by the Staff Panel and SGWP that are not addressed. We also note that, in this rebuttal testimony, we use defined terms and acronyms with the meanings defined in our September 1 testimony.

II. Response to Staff Panel Assertions

Q: What issues discussed in the Staff Panel's responsive testimony do you address in your testimony?

A: We address two principal issues: (1) Staff Panel's testimony regarding deferrals associated with the rebillings by the NYISO under its Rate Schedules 1 and 2 and the application of the MOA to those billings; and (2) the Staff Panel's proposal regarding the treatment of internally adopted accounting changes.

Q: Please describe the Staff Panel's argument in its Responsive Testimony regarding the NYISO Rate Schedule 1 and 2 rebillings.

A: In its initial testimony filed August 2, 2006, the Staff Panel proposed an adjustment to the deferral account for carrying charges it claimed were due on the NYPA MOU deferral credit balance. At page 29, lines 12-15 of the Staff Panel's Responsive Testimony, however, the Staff Panel reverses its position on NYPA MOU carrying charges, and acknowledges that the "Molloy and Richer panel testimony [of September 1, 2006] . . . pointed out the inconsistency between our [Staff Panel] testimony and the March 2003 Memorandum of Agreement (MOA)." The Staff Panel then appears to argue that because the MOA precludes the application of "all" carrying charges to amounts in the deferral account, it should also be interpreted to preclude the effect of "all" the NYISO Rate Schedule 1 and 2 rebillings that occurred after 2001.

Q: What is the problem with the Staff Panel's argument?

A: The two things (i.e., carrying charges on deferral account amounts, and rebillings occurring after 2001) are governed by different portions of the MOA, and trying to tie them together has no basis. Although the Staff Panel asserts the Company is being "inconsistent" as to how it applies the word "all" in the context of the MOA, it seems to us that it is Staff that is being inconsistent by suggesting that treatment of the NYPA MOU carrying charges is related in any way to the NYISO Rate Schedule 1 and 2 rebillings.

Q: Please continue.

A: We included a complete copy of the MOA as Exhibit __ (JMM/WRR-1) to our September 1, 2006 testimony. Pages 39-41 of that exhibit include

Section 1.2.3 of the MOA, which consists of three separate paragraphs. Our September 1, 2006 testimony at page 36, lines 1-17 noted that the third paragraph of section 1.2.3 of the MOA speaks directly and specifically to the issue of carrying charges on credits under the NYPA MOU (or other deferral account amounts). That paragraph states in relevant part that

> no additional interest or return of any kind should accrue on any items or amounts in the Deferral Account balance . . . after December 31, 2001. . . . . [A]nd all obligations to accrue interest or a return as set forth in the Commission's orders in Case Nos. 96-M-770, 96-M-0858, or any other Commission order affecting the Attachment 11 deferrals are fully and completely discharged . . . .

We appreciate the Staff Panel's recognition that the unambiguous language of this paragraph demonstrates the Company was correct not to add carrying charges to the NYPA MOU credit balance.

However, Staff errs when it asserts that its concession on this point supports its position on the NYISO Rate Schedule 1 and 2 rebillings. The third paragraph of section 1.2.3 of the MOA has no application to the NYISO Rate Schedule 1 and 2 rebillings after December 31, 2001. Rather, it is the first paragraph of section 1.2.3 of the MOA, which states that the MOA fully, finally, and comprehensively resolves all rate and reconciliation issues "through December 31, 2001," that governs the treatment of the NYISO re-bills. This issue was discussed extensively in our September 1, 2006 testimony at pages 7-30. In our testimony, as supported by the exhibits to that testimony, we succinctly stated that, by referring to the resolution of issues "through December 31, 2001":

> The MOA related to Staff's audit of the Deferral Account balance as of December 31, 2001, and was intended to resolve the starting balances as of that date as to all events and activity that were known and recorded as of that time. The MOA was not intended to bar or preclude consideration of activity occurring after December 31, 2001. Such activity was not the subject of the audit, and was not resolved by the MOA; and Staff's right to audit any post-December 31, 2001 activity was not affected by the MOA.

We showed, among other things, that this was how the Staff initially interpreted the first paragraph of section 1.2.3, as well.

It is apparent that these two paragraphs (i.e., one dealing with carrying charges, the other dealing with audit finality) address different issues. Staff's suggestion that our positions on these matters represent an "inconsistency" rests on an inaccurate portrayal of our testimony and the relevant portions of the MOA.

Q: Does the Staff Panel address the NYPA MOU elsewhere in its Responsive Testimony?

A: Yes. At pages 87-93 of its testimony, the Staff Panel again references the NYPA MOU to support its position that the MOA precludes the deferral of the NYISO Rate Schedule 1 and 2 rebillings. We do not address the

Staff Panel's Responsive Testimony arguments here, as they appear to be just a repackaging of their initial arguments, to which we responded in our September 1, 2006 testimony. However, we do believe it is appropriate to address Staff's claim that explanatory deferral account materials presented by the Company at a September 17-18, 2002 meeting with Staff were somehow misleading or incorrect.

Q: Please continue.

A: The Staff Panel cites to the portion of the September 17, 2002 report relating to the NYPA MOU, which provides that carrying charges would accrue on the deferral balance. Staff then goes on to say (page 89, lines 3-5) that "in July 2005, the Company totally reversed the hand-out position provided to Staff on September 17, 2002." However, this assertion ignores the fact that the MOA was signed in March 2003. As we discussed above, and as the Staff Panel acknowledged on page 29 of its Responsive Testimony, the third paragraph of section 1.2.3 of the MOA explicitly eliminates any requirement to accrue carrying charges on the deferral balance in recognition of the fact that the balance would be included in rate base. The Company's adjustment in July 2005 simply conformed the deferral balance to reflect this provision of the MOA, to which Staff had agreed and which it now acknowledges controls this issue.

The Company's conformance of the deferral account entries to the terms of the MOA hardly casts doubt on the candor or accuracy of the September 17, 2002 report, which predated the execution of the MOA, or suggests that the Company blithely deviated from established treatment of deferral account entries.

Q: Could you now turn to your second point relating to the Staff Panel's Proposal regarding internally adopted accounting changes?

A: Yes. The Staff Panel (on pages 100-102) takes issue with the Company's intention to submit its proposal for deferral account consideration for items affected by internally adopted accounting changes to the Director of the Office of Accounting and Finance sometime in the first half of next year. Staff is concerned such a situation would put it in an untenable position of having to audit two and a half years of accounting changes all at once, on top of its other responsibilities.

The Company has absolutely no interest in imposing undue hardship on Staff with respect to auditing this matter. Although we understand the Staff Panel's concern, we feel it is unnecessary and unwarranted. This item relates to the increase in the dollar threshold of items the Company buys that are eligible for capitalization. By raising the capitalization threshold, smaller items, or items with shorter useful lives (e.g., small tools and desktop computer equipment) are charged to expense rather than capital. These internally adopted accounting changes were implemented after the implementation of the Company's new ERP accounting system, and thus the records and information relating to them are all contained within a single system, which has been actively operated and maintained by the Accounting Services department. As a result, some of the challenges that have confronted the parties in the current audit, which relate to records that may go back nearly eight or ten years in some cases, and span three different accounting systems, simply would not exist. Thus, we do not think Staff's concerns that an audit of this area will be unmanageable or create an unreasonable burden are accurate.

Finally on this issue, if the Director of the Office of Accounting and Finance disagrees with the Company after considering its proposal to defer the effects of the internally adopted accounting changes, the Company is confident that the reversal of these items, which would primarily be reversed to capital, would not be difficult or cause any audit difficulties. In any case, and particularly given the relatively minor additional review associated with an audit and/or subsequent accounting reversal, the Staff's proposed penalty of a complete write-off of these amounts is wholly unjustified.

III. <u>Response to Assertions Relating to Goodwill</u>

Q: What is the purpose of this portion of your testimony?

A: We are replying to the responsive testimony of the SGWP and one portion of the responsive testimony of the Staff Panel relating to goodwill (pages 27-29).

Q: In its responsive testimony, the SGWP disagrees with your conclusion that the level of goodwill would not have any impact on the sharing of excess earnings. How do you respond to that testimony?

A: The SGWP fails to provide any basis for its disagreement. Its testimony only speculates that "there is the potential for an impact [on excess earnings sharing] in future years" (page 2, lines 20-21). It never even addresses our point that even if the Company were to write off 100% of its goodwill, the equity ratio would exceed the cap for earnings sharing purposes. Moreover, although the SGWP professes concern with the accuracy of the public reporting of the Company's financial position, the Company has been conducting its goodwill impairment testing following the rules as described in Financial Accounting Standard (FAS) No. 142, Goodwill and Other Intangible Assets.

Q: But the SGWP criticizes a number of assumptions in the Company's financial forecast from which that equity ratio was calculated, does it not?

A: Yes, but those criticisms are misplaced. As we explained in our testimony, the forecast is from our business plan. The forecast used for the goodwill impairment testing is based on that business plan, so management has no incentive to develop a business plan with unachievable targets.

Q: In its testimony (page 4, lines 6-18), the SGWP states that net earnings, rather than operating profits, should be used to determine earnings growth, contrary to its earlier testimony. Do you agree?

A: No. To evaluate whether goodwill is impaired, one has to determine the long-term value of the Company, taking into account expected growth in its operating profits beyond the Merger Rate Plan period. For that purpose, one must segregate out the effect of factors such as declining stranded cost recovery which are unique to the Merger Rate Plan period. Otherwise, one will have a distorted picture of the Company's long-term growth in its operating profits.

Q: The SGWP also takes issue with the assumed absence of dividends, declining debt, and rising equity in the Company's financial forecast (page 5, line 8 – page 6, line 12). How do you respond to that testimony?

A: Those assumptions do not affect the Company's operating profits and have no bearing on the growth rate of such operating profits. They therefore are immaterial to a determination of whether or not goodwill is impaired.

Q: The SGWP states that Staff's failure to take exception to the inclusion of goodwill in the forecast underlying the Merger Joint Proposal is irrelevant because they anticipated that the Company would recover that goodwill through the shared synergy savings during the Merger Rate Plan term. How do you respond to that testimony?

A: This contention makes no sense. As the SGWP recognized in its initial testimony (page 6, lines 2-23), the past practice of amortizing goodwill over time was discontinued when SFAS 141 took effect in 2001. Under SFAS 141, goodwill is no longer amortized; instead, there is an annual test to evaluate whether goodwill is impaired. So the entire notion that one would expect to see a decline in goodwill during the term of the Merger Rate Plan is simply incorrect. Moreover, if one looks at the forecast in Attachment 1 to the Merger Joint Proposal, which the SGWP cites in its responsive testimony (page 9, lines 8-9), one sees on page 7, line 30 that the amount of goodwill remains constant (at $899,513,000) from 2002 through the end of the Merger Rate Plan term in 2011. The SGWP's expectation that goodwill would decline during the Merger Rate Plan term thus is contrary both to the accounting standards applicable to goodwill and to the financial forecast underlying the Rate Plan.

Q: The SGWP asserts (page 11, lines 2-22) that it is not reasonable to expect the Company to earn above its cost of equity. Do you agree with that testimony?

A: No. That assertion is contrary to the expectations of investors, as shown in the data in Exhibit ___ (JGS-1). In that exhibit, Mr. Sauvage compares the market value of equity against the book value of equity for the regulated utilities in the SGWP's surrogate group. The exhibit shows that every single one of these companies had a market value that exceeded its book value of equity (ranging from 1.2x to 2.6x), implying that the market expected every one of these companies to earn a return on equity above its cost of equity in the future. This is consistent with the view that in order to attract equity investors, a business must be expected to earn a return on equity in excess of its cost of equity. The SGWP fails to support its view that the market would value the Company's equity at less than, or even just equal to, its book value, making it the sole outlier to this group, a group which was chosen by the SWGP in the first place.

FAS 142 states that the fair value of the reporting unit is the amount at which the unit as a whole could be bought or sold in a current transaction between willing parties. While the SGWP seems to disagree with the market's judgment, it is the market value of the Company that is critical in determining whether goodwill is impaired, not the opinion of the SGWP or any other observer.

Q: The SGWP takes the information provided by the Company in IR RAV-26, Part B (#226) and applies the 6.52% discount rate and 8.4x EBITDA multiple developed by Mr. Sauvage (page 16, lines 4-18). Based on that calculation, it determines that the Company's goodwill is worth only $441 million. Do you agree with that analysis?

A: No. The SGWP's calculation mixes apples and oranges, taking information provided by the Company, which the SGWP acknowledges the Company was not relying upon (page 16, lines 6-9), and combining it with information that Mr. Sauvage developed for a different type of analysis. Any conclusion derived from this type of mixed-up calculation is bound to be flawed.

Q: Changing subjects somewhat, the Staff Panel (at page 27, line 15 – page 29, line 3) accuses the Company of double-talk – denying that goodwill is goodwill – in order to recover $19 million of goodwill, contrary to the provisions of the Merger Joint Proposal. How do you respond to that testimony?

A: We strenuously disagree with it. Staff is trying to hide behind semantics and the word "goodwill" to obscure the real truth. The basic fact is the Company has lost $19 million in revenues for station service provided to NRG during the PowerChoice period, which NRG will not pay due to a FERC regulatory change. As Mr. Bonner and Mr. Leuthauser have explained, the Company is entitled to defer lost station service revenues under mechanisms established by the Commission in both the PowerChoice proceeding and the Merger Rate Plan. The term "goodwill" only entered into the picture because of the accounting necessitated by NRG's bankruptcy. As a result of that bankruptcy, the Company was required first to record NRG's $19 million bad debt as a reserve that reduced the pre-merger value of the Company (which, in turn, increased goodwill) and later to reverse that bad debt reserve after NRG emerged from bankruptcy. The accounting required by NRG's bankruptcy, however, does not change the basic fact that the $19 million, in reality, reflects station service revenues lost due to regulatory change.

Q: In its testimony on page 28, line 15, the Staff Panel refers to "conventional" and "unconventional" goodwill. What is Staff attempting to describe with this terminology?

A: We believe that the Staff Panel is confused about what goodwill is, or it is using these terms in an attempt to complicate a rather simple concept and create the appearance that the Company is seeking to recover goodwill, when it is not. Goodwill is being discussed in this proceeding in two contexts. One context is the issue of determining the value of goodwill and the concept of goodwill impairment testing. The calculations involved with goodwill impairment testing are quite detailed. The second context surrounding the topic of goodwill involves establishing the balance of goodwill as part of a business combination. This concept is really quite simple. We described this concept and the mechanics of recording goodwill on pages 86 and 87 of our reply testimony. The definition of goodwill in the glossaries of FAS 141, Business Combinations, and FAS 142, Goodwill and Other Intangible Assets, at Appendix F of both standards, could not be more simple and succinct. It is as follows:

> "Goodwill: The excess of the cost of an acquired entity over the net of the amounts assigned to assets acquired and liabilities assumed…."

Nowhere in these standards will you find the concepts of "conventional" or "unconventional" goodwill. There is only one type of goodwill and it is simply the price paid for the business over the fair value of the net assets (assets less liabilities) acquired. FAS 141 states that a company has up to one year in which to establish the fair value of the acquired net assets. The recording of the $19 million and other such opening balance sheet adjustments during the first fiscal year after the merger were merely adjustments to the fair value of the acquired net assets, and goodwill is simply the difference between the price that National Grid paid for the Company and the adjusted amount of net assets. There are no components of goodwill as Staff suggests — rather, it is a single derived amount. Adjustments made during the permitted one-year period are not attempts to "recover" goodwill, but simply parts of the process through which goodwill is accurately recorded.

Q: Later in its testimony, at page 67, lines 11-18, the Staff Panel refers to the $12.555 million merger delay credit adjustment that was made to the opening balance sheet with an offset to goodwill. Staff states that "by reversing this credit out of the generation stranded cost deferral account balance in March 2003, the Company is once again attempting to force ratepayers to pay for goodwill it agreed was not recoverable from ratepayers." What does Staff mean by this?

A: This is a difficult statement to interpret but we believe the Staff Panel is saying that the \$39.493 million adjustment to increase the generation stranded costs deferral balance in March 2003, which was offset by a credit to goodwill, in effect reversed either the \$12.555 million merger delay credit or the \$11.2 million of nuclear amortization recorded for the month of January 2002. The statement also suggests that this is another attempt to recover goodwill from customers. Again, Staff is either confused about the concept of what goodwill is, or is attempting to complicate the issue. This adjustment is not goodwill since goodwill by definition can only be the cost to acquire Niagara Mohawk over the fair value of the net assets of the business. As a result, the Company is not attempting to recover goodwill from customers. More importantly, the \$39.493 million includes neither the reversal of the \$12.555 million merger delay credit or the \$11.2 million of nuclear amortization recorded in January 2002.

IV. Conclusion

Q: Thank you. I have no further questions at this time.

STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

Case No. 01-M-0075

Niagara Mohawk Power Corporation d/b/a National Grid

SECOND
COMPETITIVE TRANSITION CHARGE
RESET
DEFERRAL ACCOUNT AUDIT

REBUTTAL TO DPS STAFF REPLY TESTIMONY OF SEPTEMBER 2006

September 26, 2006

Volume Two

EXHIBITS

nationalgrid

Niagara Mohawk Power Corporation d/b/a National Grid
Case No. 01-M-0075

SECOND
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REBUTTAL TO DPS STAFF REPLY TESTIMONY OF SEPTEMBER 2006

Volume Two

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Exhibits of James J. Bonner Jr. and Scott D. Leuthauser

Exhibit___(JJB/SDL-6)

Date of Request__9/1/06_ Request No. _PSC-340 Visalli (RAV-129)__

NMPC Req. No. _404_

NIAGARA MOHAWK POWER CORPORATION
Case 01-M-0075 – Second CTC Reset Compliance Filing
Request for Information

FROM: PSC-340 Visalli (RAV-129)___

Request:

On page 22, lines 7-13 of L. Reilly's testimony, it is stated:

"Absent the express reconcilable provisions, the costs and revenues were not reconcilable. Thus, no one expected the line items making up the bulk of the Company's base delivery costs and revenues over the ten-year Rate Plan period to exactly match or even approximately match the line items in the historic period. In this respect, the Rate Plan rates represent a "black box".

Regarding this statement, please provide the following information:

1. A list of the "express reconcilable provisions".
2. A list of all cost components / activities the Company considers as being in the black box, not subject to reconciliation.
3. A list of all revenue sources the Company considers as being in the black box, not subject to reconciliation.

Response:

1. The Company interprets Staff's request for a list of "express reconcilable provisions" as identifying those deferral account items for which the deferral is based on comparing the costs/revenues experienced by the Company with a specific cost/revenue line identified in the Merger Joint Proposal ("MJP"). The testimony quoted in this request refers to examples of such deferral account items. These include the deferral accounts relating to: (1) Site Investigation and Remediation ("SIR") (MJP § 1.2.4.6); (2) Economic Development Fund (MJP § 1.2.4.7); Pension and OPEB Expense (MJP § 1.2.4.13); and Incremental Expenses Associated with the Customer Outreach and Education Program and the Competition-Related and Low Income Incentive Mechanism (MJP § 1.2.4.14). Incremental Costs Associated with Extraordinary Storms (MJP § 1.2.4.5) are also deferrable only to the extent they exceed an express deductible indicated in the MJP.

The MJP also provides for deferral of amounts not based on a comparison to specific line items, but rather based on "increases or decreases [in the Company's] revenues or costs from regulated electric operations . . . ." Legislative or Regulatory Changes (MJP § 1.2.4.6); *see also* Externally Imposed Tax and Accounting Changes (MJP § 1.2.4.2.1) (same). Thus, for example, deferral amounts related to Legislative or Regulatory Changes are based on the effects those changes have on the Company's costs or revenues, compared to what the Company's costs or revenues would have been without the legislative or regulatory change. This is how the Company has calculated the deferral account effect related to Bonus Depreciation resulting from the Job Creation and Worker Assistance Act of 2002, which added subsection 168(k) to the Internal Revenue Code. (The bonus depreciation benefit reflects the return requirement on the additional deferred tax reserve generated by accelerating the Company's tax deduction in the first year of a capital investment as afforded by the legislation. The benefit is not a comparison of what is reflected in rates but rather a calculation of the incremental revenue requirement effect of the legislation going forward. The same is true for how the Company has calculated the effects of the Prescription Drug and Medicare Improvement Act of 2003. This is also how the Company has calculated the deferral account effects associated with Disputed Station Service and Standby Service (i.e., by comparing the revenues the Company would have received from regulated electric operations under tariffs approved by the Commission, with the revenues the Company is legally authorized to recover as a result on the changes brought about by the Commission's standby service rulings and FERC's station service orders). Likewise, in the event of a future legislative or regulatory change during the course of the Merger Rate Plan, any deferral amount will be based on the isolated effect such change has on the Company's costs or revenues, with and without the change.

The list of the deferral items from the MJP is included as Attachment 1 to this response. The basis for calculating each deferral is summarized in the Attachment. However, how deferral amounts should be specifically calculated will depend on the specific provisions of the MJP that cover the deferral in question.

2. Mr. Reilly's quoted reference to a "black box" was in the context of putting the historic cost analysis submitted as part of the Merger Rate Plan into perspective. As noted in the testimony, the historic analysis was presented to illustrate the basis for the initial reduced rates. It was not provided to present a set of individual cost items, each of which would serve as the basis against which deferrals would be measured. In this regard, all cost components are "in the black box" in the sense that the Merger Joint Proposal was not intended to track changes in individual components of the Company's costs, except to the extent the Merger Joint Proposal sets forth specific cost components as to which changes are subject to deferral. As noted above, some deferral account items were to be determined based on the comparison of actual costs with specific cost line items noted in the MJP. Still other deferrals were to be determined by isolating the "before-and-after" effect of the event giving rise to the deferral. As Staff recognized in its Statement in Support of the MJP, the deferral categories were designed to capture those "difficult-to-project costs" rather than attempt to reflect them in base rates at the outset. Staff Statement in Support at 11.

The Company must efficiently and effectively manage its business, and bears the risk that actual costs will exceed the costs reflected in the cost study submitted with the Joint Proposal. Such costs would include all costs that are not subject to a deferral or adjustment mechanism set forth in the Joint Proposal or the Company's tariff. These would include the Company's normal O&M and infrastructure expenditures. Unless an item or event is subject to deferral or an adjustment mechanism under the provisions of the MJP or the Company's tariff, it would be considered to be "in the black box."

The Company notes that this part of the request contains an assumption with which we do not agree. The fact that the reduced Merger Rate Plan rates were the product of a "black box" settlement does not mean changes in those elements of costs and revenues reflected therein that fall within a deferral provision are not subject to reconciliation.

3. All revenue sources are "in the black box" in the sense that the Merger Joint Proposal was not intended to track changes in individual components of the Company's revenues, except to the extent the Merger Joint Proposal sets forth specific revenue sources, changes in which are subject to deferral. These include New Services and Royalties (MJP § 1.2.4.18) and net gains from the sale or transfer of land or buildings as a credit to the SIR deferral Account (MJP § 1.2.4.18, Attachment 14). Other revenue sources subject to deferral are revenue changes arising from other deferral provisions, such as Legislative or Regulatory Changes (MJP § 1.2.4.6) and Externally Imposed Tax and Accounting Changes (MJP § 1.2.4.2.1). In addition, to the extent a revenue source was subject to an adjustment provision under the Company's tariff, it would be addressed there.

Name of Respondent:
James M. Molloy, James J. Bonner
and Legal Department

Date of Reply:
September 12, 2006

Niagara Mohawk Power Corporation d/b/a National Grid
Case 01-M-0075
Merger Rate Plan Deferral Account Provisions

Reference	Title	Provision	Basis for Calculating Deferral
1.2.4.1	Existing Deferral Balances	The beginning balance in the Deferral Account shall include the existing regulatory deferrals and the deferrals of NYISO Rate Schedule 1 and 2 costs as authorized in the Year 4 and 5 Compliance Filing in Case Nos. 94-E-0098 and 0099, all as shown on Attachment 11. The actual balances on the Effective Date shall be reflected in the Deferral Account following an audit by DPS Staff. The MRA Interest Savings Deferral included in the deferral balances shall continue through August 31, 2003 and shall be calculated in the same way as Niagara Mohawk has calculated the interest savings in Attachment 11. Deferrals associated with the Memorandum of Understanding between NYPA and Niagara Mohawk shall continue until the expiration of the agreement on August 31, 2003 or the date through which such agreement is extended.	As defined in Attachment 11 and by 03/31/2003 MOA.
1.2.4.2	Tax and Accounting Changes		
1.2.4.2.1	Externally Imposed	Niagara Mohawk shall include in the Deferral Account all of the effects of any externally imposed accounting change, and all of the effects associated with any change in the federal or state rates, laws, regulations, or precedents governing income, revenue, sales, franchise, or property taxes, if the accounting or tax change evaluated individually increases or decreases Niagara Mohawk's costs or revenues from regulated electric operations at an annual rate of more than $2.0 million per year. This provision shall also cover refunds to or payments (with interest and net of deferred taxes) reasonably made by Niagara Mohawk associated with electric operations as the result of ongoing examinations by federal and state tax authorities of Niagara Mohawk's tax returns filed prior to the Effective Date and during the Rate Plan Period.. In addition, this provision shall cover any reduction in revenues associated with the Power for Jobs Program from the revenues that are now recovered as a credit against the tax imposed pursuant to §186-2 of the Tax Law, but which may not be recovered from that source in the future either because the tax liability pursuant to that section falls below zero or for any other reason	Difference between costs and/or revenues with and without change.
1.2.4.3	Legislative or Regulatory Changes	Unless otherwise provided for in Section 1.2.3.5, Niagara Mohawk shall include in the Deferral Account all of the effects of any legislative, court, or regulatory change, which imposes new or modifies existing obligations or duties and which, evaluated individually, increases or decreases Niagara Mohawk's revenues or costs from regulated electric operations at an annual rate of more than $2.0 million per year.	Difference between costs and/or revenues with and without change.

Niagara Mohawk Power Corporation d/b/a National Grid
Case 01-M-0075
Merger Rate Plan Deferral Account Provisions

Reference	Title	Provision	Basis for Calculating Deferral
1.2.4.4	Extraordinary Inflation	During each of the first five years of the Rate Plan, Niagara Mohawk shall include in the Deferral Account the amount by which the actual inflation in the prior year as measured by Gross Domestic Product Price Index ("GDPPI") exceeds the GDPPI indexed at 4.5 percent from the Effective Date. During the second five years of the rate plan, the 4.5 percent GDPPI inflation index for excess inflation shall be adjusted to equal a percentage that is 2.3 percent over the January 2007 Blue Chip consensus forecast of inflation for calendar years 2007 and 2008. The excess inflation determined in the prior sentence shall be applied to a base that equals the amounts shown on Attachment 12 and shall be capped by the actual increases to Niagara Mohawk's departmental expenses using the methodology shown in Attachment 12. The addition to the Deferral Account shall be made when actual inflation exceeds the cumulative GDPPI inflation index from the Effective Date, provided, however, that any adjustment under this section shall never be less than zero, and provided further, that no adjustment shall be made under this section to the extent that: (a) Niagara Mohawk's earnings in the calendar year, as calculated in the earnings sharing analysis pursuant to Section 1.2.5.2, are greater than 10.6 percent or (b) Niagara Mohawk's actual electric Departmental Expenses are below the forecasted electric Departmental Expenses shown on Attachment 12. The calculation for the adjustment is illustrated in the example set forth in Attachment 12.	As set forth in Section 1.2.4.4 and Attachment 12.
1.2.4.5	Costs Associated with Extraordinary Storms	Using the methodology illustrated in Attachment 13, Niagara Mohawk shall include in the Deferral Account any Incremental Costs that exceed $2.0 million from any individual Major Storm occurring in a calendar year, provided that Niagara Mohawk has first spent a total of $6.0 million on Incremental Costs of Major Storms in that year, which has not been included in the Deferral Account. A Major Storm shall be defined in accordance with the Commission's definition in 16 NYCRR Part 97. Incremental Costs shall include overtime and associated overheads paid to employees to restore service following the Major Storm, rest time wages incurred as the result of a Major Storm as specified in Niagara Mohawk's union contracts, outside vendor costs (including the costs of crews from affiliate companies), lodging and meal charges, and material and supply charges that Niagara Mohawk would have not incurred, except for the Major Storm. Any capitalized costs shall be excluded from Incremental Costs, and proceeds from insurance shall be deducted from Incremental Costs. Niagara Mohawk shall open a work order for each Major Storm, and the Incremental Costs charged as a result of any Major Storm shall be subject to audit by the DPS Staff for reasonableness and appropriateness. The $2.0 million deductible for each Major Storm resolves any and all issues related to the Incremental Costs having the effect of reducing Niagara Mohawk's ongoing operating costs.	As set forth in Section 1.2.4.5 and Attachment 13.

Niagara Mohawk Power Corporation d/b/a National Grid
Case 01-M-0075
Merger Rate Plan Deferral Account Provisions

Reference	Title	Provision	Basis for Calculating Deferral
1.2.4.6	Site Investigation and Remediation Costs	Niagara Mohawk shall include in the Deferral Account any Site Investigation and Remediation ("SIR") Costs allocated to electric operations paid in excess or below $12.75 million per year. SIR Costs are defined in Attachment 14, and are consistent with the SIR Costs that are now being deferred under Power Choice.	Difference between actuals and amounts set forth in Section 1.2.4.6 and Attachment 14.
1.2.4.7	Economic Development Fund	Each month, Niagara Mohawk shall include in the Deferral Account any difference between one twelfth of the annual amounts shown on line 4 in Attachment 15 and the actual costs or revenue reductions occurring in that month associated with: (a) the actual Empire Zone Discounts[1] associated with Contestable Loads as defined in the tariff for SC-12 up to one twelfth of the annual amounts shown on line 6 of Attachment 15 and 50 percent of the amounts in excess of that level; (b) the actual Empire Zone Discounts other than for Contestable Loads up to one twelfth of the annual amounts shown on line 7 of Attachment 15 and 90 percent of the amounts in excess of that level; (c) the actual discounts provided under SC-11 and SC-12 during the month[2]; and (d) the fully documented actual incremental non-labor costs associated New Program Initiatives developed pursuant to Section 1.2.10.2, which have been filed with and approved by the Commission and which were incurred during the month. Niagara Mohawk's obligations under subparagraphs (a) and (b), above shall be limited to $2.0 million per year, and after this threshold is reached, the 50 percent in subparagraph (a) and the 90 percent in subparagraph (b) shall be revised to 100 percent.	Difference between actuals and amounts set forth in Section 1.2.4.7 and Attachment 15.
1.2.4.8	Service Quality Penalties	Niagara Mohawk shall include in the Deferral Account any penalties associated with failure to meet the Service Quality standards set forth in Attachment 9, not otherwise credited to customers under Section 1.2.3.7.	As defined in Attachment 9.
1.2.4.9	Customer Service Backout, Metering, and Billing Credits	Niagara Mohawk shall include in the Deferral Account the sum of: (a) the difference between the Customer Service Backout Credits provided pursuant to Section 1.3.3 to customers choosing to take service from an energy service provider other than Niagara Mohawk and SRAC associated with such Customer Service Backout Credits as set forth in Section 1.3.3; (b) following approval by the Commission of Niagara Mohawk's SRAC for metering, the difference between the metering credits provided by Niagara Mohawk pursuant to the Commission's orders in Case Nos. 94-E-0952 and 00-E-0165 and the approved SRAC, unless the Commission requires an alternative method for recovery; and (c) following approval by the Commission of Niagara Mohawk's SRAC for billing, the difference between the billing credits provided by Niagara Mohawk pursuant to the Commission's orders in Case Nos. 99-M-0631 and 98-M-1343 and the approved SRAC, unless the Commission requires an alternative method for recovery.	As set forth in Sections 1.2.4.9 and 1.3.3, until new provisions in the 04/20/2006 Order in Case 05-M-0333 become effective.

Niagara Mohawk Power Corporation d/b/a National Grid
Case 01-M-0075
Merger Rate Plan Deferral Account Provisions

Reference	Title	Provision	Basis for Calculating Deferral
1.2.4.10	Earnings Sharing Mechanism	Niagara Mohawk shall include in the Deferral Account the customers' share of the earnings above the Applicable ROE Cap calculated pursuant to the procedure set forth in Section 1.2.5, below.	As set forth in Section 1.2.4.10 and Section 1.2.5
1.2.4.11	Stranded Cost Mitigation and Adjustment	Niagara Mohawk shall include in the Deferral Account any reductions or additions to stranded costs associated with the implementation of the Niagara Mohawk Joint Proposal for Nine Mile Point (Case No. 01-E-0011), and the implementation of any of Niagara Mohawk's other agreements for the sale of the fossil and hydro generating assets to the extent allowed by the orders in those cases.[3]	Reductions or additions to stranded costs associated with implementation of the Nine Mile Point Joint Proposal (Case 01-E-0011), and implementation of any other agreements for the sale of generating assets to the extent allowed in those cases.
1.2.4.12	Renewables Cap	Niagara Mohawk shall include in the Deferral Account any revenues in the tracking/projection account as currently allowed in Rule 12.8 of Niagara Mohawk's PSC 207 tariff.	Superceded by Case 01-E-1847 Standby Service Joint Proposal.
1.2.4.13	Pension and OPEB Expense	Niagara Mohawk shall include in the Deferral Account any amounts or credits authorized or required under the procedures set forth in Attachment 16.	As set forth in Attachment 16.
1.2.4.14	Incremental Expenses Associated with the Customer Outreach and Education Program and the Competition-Related and Low Income Incentive Mechanisms	Niagara Mohawk shall include in the Deferral Account any approved incremental non-labor costs associated with the implementation of the Customer Outreach and Education Program and the Competition-Related and Low Income Incentive Mechanisms, as set forth in Attachment 8.	Difference between actuals and amounts set forth in Attachment 8.
1.2.4.15	Religious Rates	Any refunds or revenue effects associated with the resolution of Case No. 99-E-0503 shall be included in the Deferral Account.	Any refunds or revenue effects associated with resolution of Case 99-E-0503.

Niagara Mohawk Power Corporation d/b/a National Grid
Case 01-M-0075
Merger Rate Plan Deferral Account Provisions

Reference	Title	Provision	Basis for Calculating Deferral
1.2.4.16	Major Investments in Years Seven to Ten of the Rate Plan Period	Niagara Mohawk shall have the right to petition the Commission for special ratemaking treatment for major programs and expenditures that may occur in years seven through ten of the Rate Plan Period. In the petition, Niagara Mohawk must demonstrate that the proposed investment was incremental to the original 10-year forecasts underlying the rates agreed to in this Joint Proposal and that any expenses or savings go beyond such forecasts. To this end, Niagara Mohawk shall, within six months of the Effective Date and every two years thereafter, file with the Commission a five-year capital and expense budget including therein a schedule of projects consistent with and developed from the capital expenditure forecasts underpinning this Joint Proposal. Any significant additional projects would be accompanied by an engineering economic and/or technical justification. In the petition, Niagara Mohawk shall have the right to propose a sharing of any efficiency gains as a method to recover the costs for such program or expenditures. To the extent that the petition as approved by the Commission increases or decreases pre-tax net income, Niagara Mohawk shall include the differential in the Deferral Account.	Difference between proposed costs and Merger Rate Plan Financial Forecast. Company may petition for special ratemaking treatment for major programs and expenditures that are incremental to the original 10-year forecasts underlying the rates agreed to in the Joint Proposal. If the Commission approves such petition, increases or decreases in pre-tax net income shall be included in the deferral account.
1.2.4.17	Loss of Revenue from Changes to Rules 44 and 52	Niagara Mohawk shall include in the Deferral Account all verifiable losses of revenue associated with modifications to Rules 44 and 52 after the filing date of this Joint Proposal, including, without limitation, the implementation of the modification to Rule 52 set forth in Section 1.2.17.3.2, but excluding the following: (a) any loss of revenues associated with the implementation of the modification of Rule 52 set forth in Section 1.2.17.3.1, and (b) for each calendar year from September 1, 2003 through the expiration of the Rate Plan Period, the first $2.0 million of verifiable losses of revenues that would otherwise be deferred under this section plus the Actual Annual Standby Service Lost Revenue incurred under the Joint Proposal approved by the Commission in Case No. 01-E-1847 using the methodology shown in Attachment 2, page 5, of that Joint Proposal. [4]	Case 01-E-1847 Standby Service Joint Proposal Attachment 2.
1.2.4.18	New Services and Royalties	Niagara Mohawk shall include in the Deferral Account 50 percent of any net incremental revenues from Currently Provided Incidental Services pursuant to Section 2.4.1 of Attachment 23, and commercialization of R&D products and technologies pursuant to Section 4.4.1 of Attachment 23. Niagara Mohawk shall also include the sharing level for net incremental revenues associated with proposed new services which the Commission has found appropriate pursuant to Section 2.4.2 of Attachment 23.	Fifty-percent of any net incremental revenues relating to Currently Provided Incidental Services as well as the commercialization of R&D products. Sharing levels for New Services are subject to determination by the Commission.

Niagara Mohawk Power Corporation d/b/a National Grid
Case 01-M-0075
Merger Rate Plan Deferral Account Provisions

Reference	Title	Provision	Basis for Calculating Deferral
1.2.4.19	Follow-on Merger Credit	In the event that National Grid closes any additional mergers or acquisitions within the United States, Niagara Mohawk shall implement a Follow-on Merger Credit calculated pursuant to methodology set forth in Attachment 10, which is designed to credit the Deferral Account by fifty percent of the additional synergies net of costs to achieve produced by the follow-on merger and allocable to Niagara Mohawk. The Follow-on Merger Credit to the Deferral Account shall remain in effect for the remaining term of the Rate Plan. The Follow-on Merger Credit shall begin on the closing of the Follow-on Merger after Niagara Mohawk submits a compliance filing that sets forth the synergy savings, costs to achieve and allocation method pursuant to the protocols set forth in Attachment 10. Niagara Mohawk is allowed to retain fifty percent of the Follow-on Merger synergy savings through the end of the Rate Plan Period by retaining the Follow-on Merger Synergy Allowance referenced in Section 1.2.5.2.9. Subsequent to the end of the Rate Plan, the Follow-on Merger savings are allocated pursuant to Section 1.2.6.	As set forth in Section 1.2.4.19 and Attachment 10.
1.2.4.20	Delay in Effective Date	On the Effective Date, Niagara Mohawk shall include in the Deferral Account an electric customer credit equal to $405,000 per day for each day between January 1, 2002 and the Effective Date as set forth in Attachment 2, p. 2.	Defined as $405,000 per day of delay in closing.
	NOTES	[1] The Laws of 2000, Chapter 63, Part GG, Section 15 changed the name of Economic Development Zones to Empire Zones. Accordingly, Economic Development Zones or EDZ, wherever appearing in Niagara Mohawk's Tariffs shall be deemed to mean Empire Zones for all purposes. [2] Niagara Mohawk has credited the Deferral Account by $300,000 pursuant to the Customer Contract Options Section of Attachment 21. [3] See Case Nos. 94-E-0098 and 94-E-0099 for the order dated June 7, 1999, approving the sale of Huntley and Dunkirk Stations, and the order dated May 27, 1999, approving the sale of the hydro stations, the order dated April 26, 2000, approving the sale of the Albany Station; see those dockets and Case No. 96-E-0898 for the order dated October 21, 1999, approving the sale of the Oswego Station; see those dockets and Case Nos. 96-E-0909 and 96-E-0897 for the order dated December 20, 2000, approving the sale of the Roseton Station; and see Case No. 98-E-1028 for the order dated September 29, 1999, approving the sale of the Glen Park Hydro Station. [4] From Standby Service Joint Proposal 03/12/2002, Case 01-E-1847, at 6.	

Exhibit___(JJB/SDL-7)

Table 1

Long Term Forecast Summary
Updated August 1999

	Residential Non H plus H (1)	Residential TOTAL (1)"	Commercial Non H plus H (2)	Commercial TOTAL (2)"	Industrial Gen. Plus Sp. (3)	Industrial TOTAL (3)"	Street & Highway (4)	PUBLIC SALES GWh's	Borderline (5)	Total Sales GWh's (6)	Company Requirements (7)	Total Requirements (8)	PAL Residential (9)	PAL Commercial (10)	PAL TOTAL (11)	Unregulated Generators (12)	NYPA EPR,Pfj,etc. (13)	Winter Peak	Summer Peak
2000	9,955	9,959	11,822	11,876	11,292	11,888	211	33,934	22	33,956	3,847	37,803	4	24	28	30	596	5,838	6,076
2001	9,901	9,905	11,834	11,888	11,300	11,896	212	33,901	22	33,923	3,798	37,721	4	24	28	30	596	5,822	6,064
2002	9,961	9,965	11,926	11,980	11,359	11,955	209	34,109	22	34,131	3,821	37,952	4	24	28	30	596	5,851	6,080
2003	10,016	10,020	12,016	12,070	11,421	12,017	205	34,312	22	34,334	3,844	38,178	4	24	28	30	596	5,880	6,105
2004	10,051	10,055	12,100	12,154	11,477	12,073	202	34,484	22	34,506	3,863	38,369	4	24	28	30	596	5,899	6,121
2005	10,060	10,064	12,181	12,235	11,532	12,128	198	34,625	22	34,647	3,879	38,526	4	24	28	30	596	5,918	6,138
2006	10,061	10,065	12,241	12,295	11,590	12,186	195	34,741	22	34,763	3,892	38,655	4	24	28	30	596	[illegible]	[illegible]
2007	10,079	10,083	12,291	12,345	11,649	12,245	191	34,864	22	34,886	3,906	38,792	4	24	28	30	596	5,959	6,176
2008	10,127	10,131	12,355	12,409	11,710	12,306	188	35,034	22	35,056	3,925	38,981	4	24	28	30	596	5,981	6,194
2009	10,132	10,136	12,434	12,488	11,769	12,365	185	35,174	22	35,196	3,941	39,137	4	24	28	30	596	6,003	6,216
2010	10,259	10,263	12,524	12,578	11,823	12,419	181	35,441	22	35,463	3,970	39,433	4	24	28	30	596	6,044	6,256
2011	10,405	10,409	12,601	12,655	11,876	12,472	178	35,714	22	35,736	4,001	39,737	4	24	28	30	596	6,088	6,299
2012	10,522	10,526	12,628	12,682	11,921	12,517	174	35,899	22	35,921	4,022	39,943	4	24	28	30	596	6,121	6,332
2013	10,633	10,637	12,644	12,698	11,961	12,557	171	36,063	22	36,085	4,040	40,125	4	24	28	30	596	6,162	6,374
2014	10,766	10,770	12,658	12,712	11,998	12,594	167	36,243	22	36,265	4,060	40,325	4	24	28	30	596	6,209	6,422

(1)",(2)",(3)" include PALs, Unregulated Generators and NYPA, EPR, Pfj etc.
(5) is a set value which is assumed to be stable over the entire forecast horizon.
(6) is the sum of Public Sales plus Borderline Sales

2

[redacted] Report Groupings

	Report group	Sales Service	Transport Service	
ELECTRIC	Residential	SC1	Same	FRE
	General Service	SC2, SC3, SC5, SC7	Same	FGE
	Time-of-Use	SC3A, SC4, SC11, SC12	Same	FTUE
	NYPA, PFJ, EDP		Industrial Special, EDP, PFJ	FNYPE
	Other	PAL, St. & Highway Lighting, Misc.	Same	FOTHE
GAS	Residential	SC1	SC12	
	Small General Service	SC2, SC10	SC13	
	Large Commercial and Industrial	SC3, SC4, SC8 Standby, SC9 Standby	Small Firm - SC7 Large Firm - SC5 & SC8 Interruptible - SC5I	
	Special Contracts		SC9, NYSEG	

PUBLICSALES

FPUBLE

ELECTRIC SALES FORECAST (JUNE 1999)

GWHrs.

Market Classification:	Year Ending 12/31/99	Year Ending 12/31/00	Year Ending 12/31/01
Farm..................	380.694	375.979	373.120
Residential Non-Heat...	7696.045	7675.858	7644.235
Residential Heat.......	1913.982	1903.240	1883.500
Commercial Non-Heat....	10579.641	10655.981	10683.227
Commercial Heat........	1175.229	1165.707	1150.950
Industrial General.....	6869.128	6824.810	6833.320
Industrial Special.....	4466.841	4466.841	4466.841
NYPA, EDR, PfJ, etc....	596.286	596.286	596.286
Unregulated Generators.	30.081	30.081	30.081
Special Lighting.......	28.479	28.202	27.935 — PAL
St. and Highway Ltg....	209.958	210.926	212.088 — munis
TOTAL PUBLIC SALES	33946.364	33933.911	33901.583
Borderline Sales.......	21.542	21.542	21.542
TOTAL SALES - ELECTRIC	33967.906	33955.453	33923.125

Res
GE
TOU
NYP
GE
Oth
Flatline
Res 20%
Com 80%
11932
11888
11890
5003

	1999	2000	2001
Res	9991	9955	9901
Com	11785	11852	11864
Ind	11932	11888	11896

Number of Customers

Market Classification:	Year Ending 12/31/99	Year Ending 12/31/00	Year Ending 12/31/01
Farm..................	22057	21871	21685
Residential Non-Heat...	1225430	1227489	1229548
Residential Heat.......	161083	160169	159255
Commercial Non-Heat....	138806	139453	140100
Commercial Heat........	8229	8205	8181
Industrial General.....	2103	1890	1677
Industrial Special.....	85	85	85
NYPA, EDR, PfJ, etc....	0	0	0
Unregulated Generators.	29	31	33
Special Lighting.......	5105	4909	4713
St. and Highway Ltg....	1314	1322	1330
TOTAL PUBLIC SALES	1559135	1560514	1561893
Borderline Sales.......	118	117	116
TOTAL SALES - ELECTRIC	1559252	1560630	156200

Exhibit___(JJB/SDL-8)

Date of Request_2/6/06__ Request No. _PSC-209 Visalli (RAV-40)_Corrected_

NMPC Req. No. _264_

NIAGARA MOHAWK POWER CORPORATION
Case 01-M-0075 – Second CTC Reset Compliance Filing
Request for Information

FROM: PSC-209 Visalli (RAV-40)___

Request:

For purposes of this information request, assume the Company's position on "NiMo Other Disputed Station Service" is correct, i.e., such sales were included in the evaluation of the ongoing reasonableness of the Company's sales forecast as the Merger Proposal was developed. Based on that assumption:

a. Please indicate the exact level of such annual sales that was included in the Merger Joint Proposal for each of the 10 rate years based on that evaluation of the ongoing reasonableness of the Company's sales forecast as the Merger Proposal was developed. Provide an explanation as to how those exact levels of annual sales were derived and include supporting documentation (e.g., historical actual sales by month that would have been considered in the evaluation, etc).
b. Same as a. for the exact levels of gross margin included in the Merger Proposal for each of the 10 rate years for these sales.

Corrected Response:

Attached is a correction to Table No. 2. This corrected attachment incorporates a change to the actual and forecast columns in Table No. 2. These columns were inadvertently transposed. This is the only change to the attachment.

Response:

a. The exact, or even the approximate, level of annual sales for station service customers that was included in the Merger Joint Proposal sales forecast for each of the ten years in the Merger Rate Plan cannot be determined. Although the underlying historical data upon which the Merger Joint Proposal sales forecast was based included station power sales to unregulated generators under former Service Classification No. 7 ("SC-7"), such sales were redistributed to other service classifications, principally Service Classification Nos. 3 and 3-A ("SC-3 and SC-3A"). Former SC-7 was terminated on November 1, 1999, as a result of the PowerChoice Settlement[1] and customers formerly served thereunder

[1] Case 94-E-0098 *Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Niagara Mohawk Power Corporation for Electric Service. S.C. 7 TARIFF FILING.*, Order dated October 29, 1999

Form 103

transferred to other service classifications. At that point, the need to forecast SC-7 ceased.

The Company's forecasting methodology for its principal electricity service classifications, including SC-3 and SC-3A, is based on econometric techniques. Such techniques do not rely upon customer-by-customer projections, rather these techniques mathematically identify, chiefly through regression analysis, causal relationships between a dependent variable—in this case, electricity sales for a given service or customer class—and explanatory variables selected by the forecaster.[2] Consequently, once a formerly separately identifiable population is subsumed into another population, it ceases to exist as a separately identifiable population for econometric forecasting purposes.

One of the main purposes of sales forecasting is to provide the basis for generating the billing units used to design rates that will recover the allowed revenue requirement over the period of time these rates will be in effect. Actual customer populations for which billing units are derived from the sales forecast are dynamic—new customers are added, old customers are terminated, and electricity usage for the population will vary with economic forces and weather.

Assuming for this discussion, the Company misstated its forecast for the service classifications under which station power customers are served by failing to take into account new station power sales to its former generating plants upon sale of these plants to new owners, one would expect to detect that variance by comparing actual sales in affected service classifications to forecasted sales, especially in the early years of the forecast at the time the new sales were realized. The largest of these new station power customers NRG Energy acquired the Huntley, Dunkirk and Oswego Harbor Stations from Niagara Mohawk in mid-to-late1999[3], PSEG Power acquired the Albany Steam Station from Niagara Mohawk in early 2000,[4] and Constellation Energy acquired the Nine Mile Point Nuclear Stations from Niagara Mohawk in late 2001.[5]

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[2] See *Merger Petition and Joint Proposal Financial Forecast and Supporting Workpapers, January 17, 2001*, Workpapers of G.S. Mann Electric Sales Forecast 2000-2014, pp. 67-145

[3] Case 94-E-0098 *Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Niagara Mohawk Power Corporation for Electric Service. JOINT PETITION FOR AUTHORITY TO TRANSFER COALFIRED GENERATING ASSETS*, Order dated June 7, 1999 and Case 94-E-0098 *Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of NiagaraMohawk Power Corporation for Electric Service. JOINT PETITION FOR AUTHORITY TO TRANSFER THE OSWEGO GENERATING FACILITY*, Order dated October 21, 1999

[4] Case 94-E-0098 *Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Niagara Mohawk Power Corporation for Electric Service. JOINT PETITION FOR AUTHORITY TO TRANSFER THE ALBANY GENERATING FACILITY*, Order dated April 26, 2000

[5] Case 01-E-0011 *Joint Petition of Niagara Mohawk Power Corporation, New York State Electric & Gas Corporation, Rochester Gas and Electric Corporation, Central Hudson Gas & Electric Corporation, Constellation Nuclear, LLC and Nine Mile Point Nuclear Station, LLC for Authority Under Public Service Law Section 70 to Transfer Certain Generating and Related Assets and for Related Approvals*, Order dated October 26, 2001

As shown in the Attachment to this response, no such sales variance is detected, either before Merger Rate Plan forecast (Table No. 1) or in the Merger Rate Plan forecast to date (Table No. 2). In each of the years shown in the foregoing analyses, the sum of the actual SC-3 and SC-3A sales is below the forecasted sales. Consequently, the Company is not reaping a windfall from the new sales to station power customers unaccounted for in the forecast. Such sales are only partially offsetting the sales losses attributable to other customers. Thus, the Company is under-recovering not over-recovering its revenue requirement from these service classes.

b. See (a) above.

Name of Respondent: James J. Bonner Jr. Date of Reply: May 15, 2006

Attachment to Information Request No. 264 [PSC-209 Visalli (RAV-40)]

TABLE NO. 1

Electric Sales -- Actual vs Forecast (w/SC7 reported at parent tariff)

Variance (GWh)

	1999			2000			2001		
	Actual [1]	Forecast [2]	Variance	Actual [1]	Forecast [2]	Variance	Actual [1]	Forecast [2]	Variance
SC3	5,776	6,367	(591)	4,929	6,357	(1,429)	4,492	6,336	(1,844)
SC3A	3,691	3,324	367	2,566	3,323	(757)	2,754	3,323	(569)
Total	9,467	9,691	(224)	7,495	9,681	(2,186)	7,247	9,660	(2,413)

[1] Actual Sales per FERC Form 1 (with SC7 reported at parent tariff)
[2] Forecast Sales (June 1999)

TABLE NO. 2

Electric Sales -- Actual vs Forecast

Variance (GWh)

	2002			2003			2004		
	Actual [3]	Forecast [4]	Variance	Actual [3]	Forecast [4]	Variance	Actual [3]	Forecast [4]	Variance
SC3	5,730	6,333	(603)	5,752	6,384	(632)	6,008	6,431	(423)
SC3A	3,928	3,942	(14)	4,061	3,942	119	4,347	3,942	405
Total	9,658	10,275	(617)	9,813	10,325	(512)	10,355	10,373	(18)

[3] 2002-2004 Provided by G. Mann on 5/12/2005
[4] Merger Rate Plan Forecast Sales

Exhibit___(JJB/SDL-9)

STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

Case No. 01-E-1847

Niagara Mohawk Power Corporation

COMPLIANCE WITH
OPINION NO. 01-4
IN
CASE NO. 99-E-1470
ON
STANDBY SERVICE RATES

JOINT PROPOSAL

March 12, 2002

Volume One

NIAGARA MOHAWK POWER CORPORATION

CASE NO. 01-E-1847

COMPLIANCE WITH
OPINION NO. 01-4
IN
CASE NO. 99-E-1470
ON
STANDBY SERVICE RATES

JOINT PROPOSAL

Volume One

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JOINT PROPOSAL

Filing Letter

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March 12, 2002

Hon. Janet Hand Deixler
Secretary
New York State
Public Service Commission
Albany, NY 12223-1350

Re: Case 01-E-1847 – In the Matter of the Compliance Filing of Niagara Mohawk Power Corporation in Response to Opinion No. 01-4 on Standby Service Rates.

Dear Secretary Deixler:

Enclosed for filing are the original and twenty-five copies of the Joint Proposal entered into among Niagara Mohawk Power Corporation ("Niagara Mohawk"), Department of Public Service Staff, the Independent Power Producers of New York, Orion Power New York GP, Inc., NRG Companies, Multiple Intervenors and National Fuel Gas Distribution Corporation. As described in the Joint Proposal, the signatories agree that the Joint Proposal settles and resolves all issues regarding Niagara Mohawk's electric standby rates described therein except to the extent indicated on the party's signature page.

Also enclosed for filing are Supporting Workpapers prepared by Niagara Mohawk in relation to the Joint Proposal.

The Joint Proposal and Supporting Workpapers are being served today via electronic mail and first class mail on the active parties lists for Cases 01-E-1847 and 01-M-0075.

Respectfully submitted,

Lisa Gayle Bradley
Gloria Kavanah

cc: Hon. J. Michael Harrison, Administrative Law Judge (via hand delivery and electronic mail)
Hon. Joel Linsider, Administrative Law Judge (via hand delivery and electronic mail)
Active Parties List 01-E-1847 (via first class mail and electronic mail)
Active Parties List 01-M-0075 (via first class mail and electronic mail)

JOINT PROPOSAL

Active Party List
Case No. 01-E-1847
01/28/02

CASES 00-E-1847 AND 99-E-1470
ACTIVE PARTY LIST
(As of 1/28/02)

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JOINT PROPOSAL

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12/11/01

CASE 01-M-0075
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JOINT PROPOSAL

Joint Proposal

STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

In the Matter of the Compliance Filing of Niagara Mohawk Power Corporation in Response to Opinion No. 01-4 on Standby Service Rates.

Case No. 01-E-1847

JOINT PROPOSAL

On November 28, 2001 Niagara Mohawk Power Corporation ("Niagara Mohawk" or "Company") filed with the State of New York Public Service Commission ("Commission") proposed tariff leaves for electric standby service, with an explanatory filing letter, in compliance with Commission Opinion No. 01-4[1] and the Joint Proposal filed on October 11, 2001 in Case No. 01-M-0075,[2] as revised in a filing dated November 6, 2001. Following the filing and upon notice to the parties in Cases 01-M-0075 and 99-E-1470, Niagara Mohawk conducted a technical conference regarding the filing. Thereafter and also upon notice, interested parties entered into confidential settlement discussions in accordance with the Commission's Rules and Regulations, 16 N.Y.C.R.R. Section 3.9.

These discussions have resulted in this Joint Proposal. The Joint Proposal is designed to resolve issues raised by the various parties in connection with the original filing. It is being sponsored by Niagara Mohawk and the following parties:

State of New York Department of Public Service,

Multiple Intervenors,

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[1] Case No. 99-E-1470, Proceeding on Motion of the Commission as to the Reasonableness of the Rates, Terms and Conditions for the Provision of Electric Standby Service, Opinion No. 01-4 (issued October 26, 2001).
[2] Case No. 01-M-0075 - Joint Petition of Niagara Mohawk Holdings, Inc., Niagara Mohawk Power Corporation, National Grid plc and National Grid USA for Approval of Merger and Stock Acquisition. The Joint Proposal filed in 01-M-0075 was approved by the Commission in Opinion and Order Authorizing Merger and Adopting Rate Plan (issued December 3, 2001).

Independent Power Producers of New York,

National Fuel Gas Distribution Corporation,

NRG Companies, and

Orion Power New York GP, Inc.

The signatories ("Settling Parties") agree that this Joint Proposal settles and resolves all issues regarding electric standby service rates that relate to matters set forth herein, except as provided in Section 1 hereafter as to those matters reserved by Settling Parties.

The following sets forth the agreement of the Settling Parties:

1. STANDBY SERVICE RATES, TERMS AND CONDITIONS

Except to the extent otherwise indicated by a Settling Party on its signature page to this Joint Proposal, the Settling Parties agree to Attachment 1 hereto.

2. LOST REVENUE RECOVERY

2.1. Deferral and Rate Adjustment for Standby Service Lost Revenue

2.1.1 Calculation of Standby Service Lost Revenue

Each month, Niagara Mohawk shall calculate the verifiable lost or gained revenue per customer associated with the implementation of the Standby Service tariff included in Attachment 1 by comparing the delivery service billings under the Standby Service tariff to the delivery service billings that would have been made by Niagara Mohawk under its superseded Rule 12 or other applicable tariff in effect prior to the Effective Date of this Joint Proposal ("Standby Service Lost Revenue"). For customers with On-Site Generator ("OSG") and Wholesale Generator's that were exempt from Rule 12 metering requirements, the comparison shall be the delivery service billings under the Standby

Service tariff to the delivery service billings that would have been made by Niagara Mohawk under the standard Service Classification. To calculate the billings for customers with an OSG and Wholesale Generator's that would have otherwise been subject to Rule 12 metering requirements the demand in kW and monthly energy in kWh of the generator shall be determined as follows: (i) in the event a meter exists on the generator, the customer will supply to the Company the appropriate kW and kWh determinants, or (ii) if no meter exists on the generator, the customer will supply to the Company the number of hours that the generator actually operated during the month. For this purpose, the monthly peak generation in kW shall be set at the nameplate capacity as set forth in Form G and the monthly generation in kWh shall be the product of the nameplate capacity in kW times the operating hours. If the number of operating hours are not provided, the customer and the Company shall set forth in Form G an agreed upon expected monthly generation in kWh. The estimates set forth in Form G shall be reviewed by Niagara Mohawk, DPS Staff, and the customer periodically and revised as necessary to preserve the reasonableness of the lost revenue estimates.[3] Standby Service Lost Revenue shall be calculated using the methodology set forth in Attachment 2. The calculation shall be based on the entire usage at the customer's location, even if the customer installs generation that is served under a split billing option, where a portion of its usage continues to be billed under Niagara Mohawk's standard delivery tariffs and a portion of its usage is billed under the Standby Service tariff after the installation of generation at the customer's location. Because the portion of the customer's SC-7

[3] This review may include an examination of the underlying billing data for the periods before and after the installation of the generator and may result in an adjustment to the lost revenue estimate.

standby service billing above the 15% is billed on the same standard tariff rates as that used for Rule 12 there should not be an impact on the Standby Service Lost Revenue Deferral Account for this portion of the calculation.

2.1.2 Standby Service Lost Revenue Deferral Account

Niagara Mohawk shall establish a deferral account for Standby Service Lost Revenue ("Standby Service Lost Revenue Deferral Account"). The Standby Service Lost Revenue that Niagara Mohawk incurs each month shall be added to or subtracted from the Standby Service Lost Revenue Deferral Account each month after the Effective Date of the Standby Service tariff. No interest or carrying charge will accrue on the balance in the Standby Service Lost Revenue Deferral Account. Rather, for purposes of Niagara Mohawk's earnings reports, the amount in this Lost Revenue Deferral Account shall be added to or subtracted from Niagara Mohawk's rate base.

2.1.3 Standby Service Lost Revenue Rate Adjustment

On August 1, 2003 and every two years thereafter, and coincident with its CTC reset filing as described in Section 1.2.3.3 and Attachment 7 of the company's Rate Plan approved in Case No. 01-M-0075, Niagara Mohawk shall make a compliance filing to calculate a Standby Service Lost Revenue Rate Adjustment, as further described and illustrated in Attachment 2. The compliance filing will: (1) set forth the amount that has been accrued in the Standby Service Lost Revenue Deferral Account from customers placed on the Standby Service tariff since its initial implementation through June 30 of that calendar year; (2) estimate the amount of additional accruals between July 1 and December 31, of that calendar year and the two subsequent calendar years based on an extrapolation of the actual accruals for the six-months ended June 30; (3) set forth a reconciliation between actual and previously estimated Standby Service Lost Revenue accruals for all prior CTC reset periods; and (4) calculate a rate adjustment designed to recover the sum of items (1), (2), and (3) over the ensuing two calendars years ("Standby Service Lost Revenue Rate Adjustment"). The Standby Service Lost Revenue Rate Adjustment shall be implemented only when the sum of Niagara Mohawk's June 30 cumulative deferral balance under section 1.2.4 of the Niagara Mohawk's Rate Plan approved in Case No. 01-M-0075, as amended below, and the June 30 cumulative deferral balance under Section 2.1.3 of this Joint Proposal is positive, indicating that customers owe Niagara Mohawk money. The Standby Service Lost Revenue Rate Adjustment shall be determined in the manner set forth in Attachment 7 of Niagara Mohawk's Rate Plan approved by the Commission in Case No. 01-M-0075 regarding the implementation of rate adjustments for its other deferrals at the time of its CTC Reset. The methodology used to allocate the Standby Service Lost Revenue Rate Adjustment among Niagara Mohawk's individual rate classes shall be subject to review and possible challenge by the parties at the time that the Standby Service Lost Revenue Adjustment is filed, and shall only become effective after approval by the Commission, consistent with the requirements of the State Administrative Procedures Act ("SAPA"). Following Commission approval, the Standby Service Lost Revenue Rate Adjustment shall be applied to delivery service usage on and after January 1 of the calendar year following the filing, remain in effect for two years, and will not be shown separately on Niagara

Mohawk's bills, but shall be added to or subtracted from the rate adjustment associated with the Niagara Mohawk's CTC Reset.

2.1.4 Niagara Mohawk's Rate Plan

For the time period that it is approved by the Commission, the procedure set forth in this section shall supersede the deferral of Standby Service Lost Revenues under Section 1.2.4.17 of Niagara Mohawk's Rate Plan, as approved by the Commission in Case No. 01-M-0075. Accordingly, that section shall read as follows as long as the procedure set forth in this Joint Proposal remains in effect:

> "1.2.4.17 Loss of Revenue from Changes to Rules 44 and 52
>
> Niagara Mohawk shall include in the Deferral Account all verifiable losses of revenue associated with modifications to Rules 44 and 52 after the filing date of this Joint Proposal, including, without limitation, the implementation of the modification to Rule 52 set forth in Section 1.2.17.3.2, but excluding the following: (a) any loss of revenues associated with the implementation of the modification of Rule 52 set forth in Section 1.2.17.3.1, and (b) for each calendar year from September 1, 2003 through the expiration of the Rate Plan Period, the first $2.0 million of verifiable losses of revenues that would otherwise be deferred under this section plus the Actual Annual Standby Service Lost Revenue incurred under the Joint Proposal approved by the Commission in Case No. 01-E-1847 using the methodology shown in Attachment 2, page 5, of that Joint Proposal.

This provision shall remain in effect for as long as the Joint Proposal in Case No. 01-E-1847 remains in effect as approved by the Commission in that proceeding. In addition, all secondary references to deferrals associated with Section 1.2.4.17 shall eliminate the reference to Rule 12. An example showing the operation of the exclusion to the Deferral Account is included in Attachment 2.

3. MISCELLANEOUS

3.1 No Admissions. This Joint Proposal is and represents a compromise of conflicting views and positions of the parties in Case Nos. 01-E-1847 and 99-E-1470 and any other proceedings. It shall not be construed, interpreted or otherwise deemed in any respect to constitute an admission, concession, or other agreement by any party regarding any allegation or contention in Case Nos. 01-E-1847 and 99-E-1470 or any other proceeding. The Joint Proposal shall not be construed, interpreted or otherwise deemed in any respect to be a precedent or to have precedential value from Case Nos. 01-E-1847 and 99-E-1470 or with respect to any other proceeding.

3.2 Discussion Privileged. The discussions which have produced this Joint Proposal have been conducted on the explicit understanding that any and all prior proposals and discussions relating thereto are and shall be privileged, shall be without prejudice to the position of any party or participant presenting such offer or participating in any such discussions or proceedings, and are not to be used in any manner in connection with these or any other proceedings.

3.3 Commission Acceptance a Condition. Except as to those issues expressly identified by the Settling Parties on their signature pages to this Joint Proposal as being reserved and contested, this Joint Proposal is expressly conditioned upon the Commission's acceptance of all provisions hereof without change or condition. In the event the Commission does not by order accept it in its entirety, each signatory shall have the right to withdraw from the Joint Proposal upon written notice to the Commission. If Niagara Mohawk gives such notice, this Joint Proposal shall be deemed withdrawn, it shall not constitute any part of the record in this proceeding or be used for any other purpose, and each of its provisions shall be deemed to be null and void.

3.4 Dispute Resolution. In the event of any disagreement over the interpretation of this Joint Proposal or the implementation of any of its provisions, which disagreement cannot be resolved informally among the signatory parties, such disagreements shall be resolved in the following manner unless otherwise provided herein. The parties shall promptly convene a conference and in good faith shall attempt to resolve such disagreement. If any such disagreement cannot be resolved by the parties, any party may petition the Commission for relief on a disputed matter.

3.5 Commission Authority. Nothing in this Joint Proposal shall be construed to limit the Commission's authority to reduce the rates and charges provided for herein should it determine, in accordance with the Public Service Law, that the established rates are in excess of just and reasonable rates for Niagara Mohawk's electric standby service.

3.6 Integration and Merger. This Joint Proposal expresses the entire understanding of the parties with respect to the subject matter hereof and the settlement of the issues that are the subject of this Joint Proposal. This Joint Proposal supersedes any prior written or oral representations, agreements or understandings with respect to the specific matters addressed herein.

Respectfully submitted,

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The Independent Power Producers of New York, Inc., reserves and contests the Competitive Transition Charge components of the proposed SC-7 electric standby service rates in Attachment 1 hereto.

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JOINT PROPOSAL

ATTACHMENT 1

Proposed SC-7 Tariff Language

TABLE OF CONTENTS (continued)

GENERAL INFORMATION

1. DEFINITIONS AND ABBREVIATIONS: (Continued)

1.39 "Control Area" - An electric system or systems, bounded by interconnection metering and telemetry, capable of controlling generation to maintain its interchange schedule with other Control Areas and contributing to the frequency regulation of the interconnection.

1.40 "Load Zone" - One of several (currently eleven) geographical areas located within the New York Control Area that is bound by one or more of the fourteen New York State transmission interfaces. Electricity Supply Service prices within different load areas may differ due to transmission system congestion and electric losses.

1.41 "NERC" - North American Electric Reliability Council, or any successor organization thereto.

1.42 "NPCC" - Northeast Power Coordinating Council or any successor organization thereto.

1.42.1 "NYSRC" - New York State Reliability Council or any successor organization thereto.

1.43 "NYISO" - New York Independent System Operator or any successor organization thereto.

1.44 "Competitive Transition Charge" (CTC) - A non-bypassable charge, except as otherwise provided in this Tariff, however designated, for recovery of the Company's costs associated with the transition to a competitive market in electricity generation and supply.

1.45 "Electricity Supply Cost" (ESCost) - the cost of Electricity Supply Service Pursuant to Rule 46.

1.46 "New York Power Authority" (NYPA) - Power Authority of the State of New York or any successor organization thereto.

1.47 "Distribution Delivery Charge" - Delivery charges related to furnishing, maintaining, and operating the connection between the Customer's Electricity Supply Service source and the customer's point of delivery inclusive of the NYISO Transmission Service Charge.

1.48 "Electrically Isolate" - Separation of electrical points of contact where interconnection may occur, if (a) such separation is at least 100 feet from any other interconnected electrical service of such customer, or (b) the disconnected isolated service is not within the same building structure as any other interconnected electrical service of such customer and not housed within a common enclosure with other interconnected breakers and/or fuses of such customer.

1.49 "Fully Loaded Rates" - As used in Rule 28 of this Tariff, this term shall mean rates developed by utilizing a fully embedded costing methodology for services performed. The methodology shall be based upon the four pricing components of direct costs, indirect costs, taxes and surcharges, and profit.

1.50 "Emergency Power System" - A system legally required and classed as emergency by codes or any governmental agency having jurisdiction that automatically provides an independent reserve source of electricity, upon failure or outage of the normal power source, to elements of a power system essential to the safety of human life, or a system used exclusively by customers during interruptions of Electric Service and/or in response to NYISO direction for Emergency Response Programs and/or Unforced Capacity requirements for NYISO special case resources.

GENERAL INFORMATION

I. DEFINITIONS AND ABBREVIATIONS

1.70 "Day-Ahead LBMP" - the LBMPs calculated based upon the NYISO's Day-Ahead Security Constrained Unit Commitment Process.

1.71"Renewable On-Site Generation" - Non-fossil fuel based energy that is largely sustainable or reclaimable from natural resources.

1.72"Electric and Gas System Bulletin No. 309, Procedure for New or Changed Customers' Services" - Niagara Mohawk's specifications for electrical installations and supplemental bulletins thereto as they may be amended from time to time.

1.73 "Unforced Capacity" ("UCAP") - The measure by which Installed Capacity Suppliers are rated to quantify how much they (each) can contribute to the New York Control Area's (NYCA) Installed Capacity Requirement. Each Supplier's resource is assigned an Unforced Capacity value based upon its (twelve-month rolling average) reliability. While the overall NYCA peak load and reserve requirement is fixed for a year, a resource's Unforced Capacity can change each month.

1.74 "Unforced Capacity Requirement" ("UCAPR") - The amount of UCAP reserves (in percent or fraction) that each LSE must procure prior to each Obligation Procurement Period, as such term is defined in the NYISO Tariff. The UCAPR is designed to insure no more than a one-day interruption in ten years (as a result of generation shortages) and is calculated by the NYISO.

1.75 "Ancillary Services" means as defined in the NYISO OATT as amended from time to time, those services that are necessary to support the transmission of Capacity and Energy from resources to Loads while maintaining reliable operations of the NYS Transmission System in accordance with Good Utility Practice.

1.76 "Wholesale Generator" - A company whose primary business is the production of electricity for sale into the wholesale electricity market.

SERVICE CLASSIFICATION NO. 1 (Continued)

H. **ON-SITE GENERATION SPECIAL PROVISION**

Customers are obligated to certify, subject to the Company's approval, on-site generation (OSG) installations on the Company's Form G, Application For Electric Standby Service, and will be subject to the provisions of Service Classification No. 7 unless the customer has electrically isolated a portion of their load as defined in Rule 1.48 or has installed the OSG to be used exclusively as an Emergency Power System as defined in Rule 1.50.

SERVICE CLASSIFICATION NO. 1B (Continued)

H. **ON-SITE GENERATION SPECIAL PROVISION**

Customers are obligated to certify, subject to the Company's approval, on-site generation (OSG) installations on the Company's Form G, Application For Electric Standby Service, and will be subject to the provisions of Service Classification No. 7 unless the customer has electrically isolated a portion of their load as defined in Rule 1.48 or has installed the OSG to be used exclusively as an Emergency Power System as defined in Rule 1.50.

SERVICE CLASSIFICATION NO. 2 (Continued)

L. **ON-SITE GENERATION SPECIAL PROVISION**

Customers are obligated to certify, subject to the Company's approval, on-site generation (OSG) installations on the Company's Form G, Application For Electric Standby Service, and will be subject to the provisions of Service Classification No. 7 unless the customer has electrically isolated a portion of their load as defined in Rule 1.48 or has installed the OSG to be used exclusively as an Emergency Power System as defined in Rule 1.50.

Customers served under SC-2D with a contract demand less than 50 kW shall have the option to remain on the SC-2D standard service classification.

SERVICE CLASSIFICATION NO. 3 (Continued)

F. **ON-SITE GENERATION SPECIAL PROVISION**

Customers are obligated to certify, subject to the Company's approval, on-site generation (OSG) installations on the Company's Form G, Application For Electric Standby Service, and will be subject to the provisions of Service Classification No. 7 unless the customer has electrically isolated a portion of their load as defined in Rule 1.48 or has installed the OSG to be used exclusively as an Emergency Power System as defined in Rule 1.50.

SERVICE CLASSIFICATION NO. 3A (Continued)

E. **ON-SITE GENERATION SPECIAL PROVISION**

Customers are obligated to certify, subject to the Company's approval, on-site generation (OSG) installations on the Company's Form G, Application For Electric Standby Service, and will be subject to the provisions of Service Classification No. 7 unless the customer has electrically isolated a portion of their load as defined in Rule 1.48 or has installed the OSG to be used exclusively as an Emergency Power System as defined in Rule 1.50.

SERVICE CLASSIFICATION NO. 4 (Continued)

D. **ON-SITE GENERATION SPECIAL PROVISION**

Customers are obligated to certify, subject to the Company's approval, on-site generation (OSG) installations on the Company's Form G, Application For Electric Standby Service, and will be subject to the provisions of Service Classification No. 7 unless the customer has electrically isolated a portion of their load as defined in Rule 1.48 or has installed the OSG to be used exclusively as an Emergency Power System as defined in Rule 1.50.

SERVICE CLASSIFICATION NO. 5(Continued)

F. **ON-SITE GENERATION SPECIAL PROVISION**

Customers are obligated to certify, subject to the Company's approval, on-site generation (OSG) installations on the Company's Form G, Application For Electric Standby Service, and will be subject to the provisions of Service Classification No. 7 unless the customer has electrically isolated a portion of their load as defined in Rule 1.48 or has installed the OSG to be used exclusively as an Emergency Power System as defined in Rule 1.50.

SERVICE CLASSIFICATION NO. 7
SALE OF STANDBY SERVICE TO CUSTOMERS WITH ON-SITE GENERATION FACILITIES

APPLICABLE TO USE OF SERVICE FOR:
This Service Classification No. 7 is applicable to:

(a) Customers who have generation installed on their site, whether the generation equipment is owned by the customer or a third party;

(b) Customers who are directly interconnected with a Wholesale Generator, as defined in Rule 1.76; and

(c) Wholesale Generators who require service from the Company when their own generating equipment is not sufficient to meet their own load.

More specifically:

1. Standby service rates shall apply to: (a.) customers with on-site generation serving load that is not isolated from the grid in accordance with Rule 1.48; (b.) Wholesale Generators that rely on the electric utility to serve electric loads that would otherwise be served by the generator such as station power used for the heating, lighting, air-conditioning, and office equipment needs of the buildings housing the generator and associated support facilities located on a generating facility's site, and/or to facilitate the re-starting of the generator following an outage. Standby rates will also apply to Wholesale Generators that take station service through the same bus bar as they supply the wholesale grid.

2. Same Bus Bar

"Same Bus Bar" is defined as a common electrical point of interconnection on the same physical bus bar structure located at one substation of the utility and an individual customer's system at the single voltage level at which the customer takes service and has taken service as of March 2002. This common point of interconnection may include up to one load serving connection, or tap, (such tap is in addition to the single point of delivery service from the generating customer to the NMPC delivery system being metered), from a single physical bus bar (one tap must be connecting the customer's generation output to the bus and a second tap must be connecting the customer's electric service to the bus) located at an NMPC substation. The customer's generation must be on a single unitary tract of land; adjoining and abutting the land upon which the NMPC substation is located and the points of delivery and receipt must not be more than 500' apart. The presence of Company equipment, including but not limited to switches, fuses, transformers, and circuit breakers, between the point(s) of delivery is not considered Same Bus Bar. If the single physical bus bar or a portion thereof, is relied upon to deliver electricity between the customer's generation and customer's load, i.e., the point of common coupling, the customer will enter into a financial agreement with the Company for payment of use of that portion of the Company's equipment that comprises the point of common coupling necessary to move the generation from the customer to the customer's load. The amount of the load will be netted from the customers' generation on a 15-minute interval basis. The customer is responsible for all costs of metering, reconfiguration, instrument transformers and telemetry equipment necessary to implement the netting of generation and load that meets the requirements above. When the forgoing requirements are met, the customer will be eligible to net generation and load. In this case, the customer, upon entering into a financial agreement with the Company, will be considered as netting the customer's load from "behind the meter" for the limited purposes of electricity supply service provision under Rule 46 and for delivery services.

3. The Parent Service Classification shall be defined based upon the applicable Contract Demand at the delivery point (as initially calculated by the Company).

4. <u>Exemptions From SC-7</u>
The following customers shall not be subject to S.C.7 but shall be served under the customer's otherwise applicable service classification. Each of applicability provisions 3(C), 3(D), and 3(F) shall be evaluated and considered for termination in the review of the August 2005 CTC Reset filing. Standby service rates shall not apply to:
A. "<u>Behind the Meter" Service</u>
Self supplied electricity where a Wholesale Generator, when operating, supplies all of its electric energy needs from "behind the meter" (that is, the energy does not pass through the point of interconnection between the generator's facility and the utility's retail delivery system to which it is interconnected).
B. <u>Separately Metered Accounts Not Served by OSG</u>
All separately metered service accounts within the premises whereby electricity consumption is not otherwise served directly through facilities owned by the customer (e.g., power to the facility's outer buildings) shall be provided at the standard tariff rates for the Parent Service Classification.

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C. Small Generators Operating Before December 31, 2005
Customers with a nameplate aggregate generator(s) 5 kVA or smaller and installed and operating prior to December 31, 2005 shall be served at the standard tariff rates for the Parent Service Classification.

D. Certain Customers Grandfathered Under Rule 12: Standby service rates shall not apply to customers served on the standard classification as of January 1, 2002 that have executed a form Gf and were grandfathered from Rule 12.1 of PSC 207 as of January 1, 2002; except where such customer is a SC-3 subtransmission or transmission voltage level or SC-3A subtransmission or transmission voltage level customer and is a Wholesale Generator. This grandfathering provision shall expire and no longer apply and Standby Service Rates shall apply if and at such time the customer installs any New Generating Equipment and this SC-7 Tariff shall apply as defined herein.

For the purposes of this provision, New Generating Equipment shall include, the installation or the replacement of the following items of electric plant:

(i) for steam production plant: boiler plant equipment; engines and engine-driven generators; and turbogenerator units;
(ii) for nuclear production plant: reactor plant equipment, and turbogenerator units;
(iii) for hydraulic production plant: turbines, and generators; and
(iv) for other electric production equipment: fuel holders, producers, and accessories; prime movers; and generators.

The installation or replacement of electric plant ordinarily classified as maintenance or repair expenses or replacements under warranty as a result of a defect or casualty loss, or of water wheels, automotive and marine internal combustion engines fired by natural gas which were designed and installed with the intention of routine replacement, and generator rewinds shall not be deemed to be New Generating Equipment.

E. NYPA Programs and Individually Negotiated Contracts
Standby service rates shall not apply to that portion of a customer's delivery service associated with the provision of applicable NYPA programs or that portion of delivery service served under the terms and conditions of an individually negotiated SC-11 and SC-12 contract.

F. Renewable Generators
Standby service rates shall not apply to customers who install Renewable On-Site Generators that are i) farm service customers operating anaerobic digesters processing manure if manure is 80% or more of the fuel used annually by the On-Site Generator, or (ii) photovoltaic and wind technologies, if the customer commits in a written agreement with the Company that the On-Site Generators shall comply to all of the following requirements:

a) The nameplate capacity of the OSG (in aggregate if more than one unit exists) shall at no time exceed (1) 50.0 kVA for photovoltaic and wind technologies, or (ii) 130 kVA for farm service customers operating anaerobic digesters.
b) The electricity supply is for use at the customer premises only and not for resale to any other party or for use at any other party or for use at any other premises.
c) The Renewable OSG is connected to the customer's electric system using an automated or manual transfer switch or the electrical equivalent of such a switch approved by the Company consistent with Electric System Bulletin 750 as it may be amended from time to time.

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d) The customer executes and the Company accepts a Form G as required under the special provisions of the applicable Service Classification for all generators on the premises. The customer shall state its intended use of the OSG facilities on the Form G in the blank spaces provided for special conditions.

In the event the customer fails to comply with provisions (a) through (d) above, the Company shall have the following rights:

(i) to bill the customer for those amounts of total Electric Service which the Company reasonably estimated were received by the customer during times when Electric Service from the Company was available to the customer; and

(ii) to require the customer to install OSG meter(s) on all of its generators on the premises within a mutually acceptable schedule and upon receipt of written notice from the Company.

This renewable OSG provision shall terminate for each technology (wind, photovoltaic, and anaerobic digestors) at such time as the calculated deferral sub-account described herein exceeds an aggregate of $250,000 for each technology Company-wide on a prospective (forecast) basis through the rate plan period (i.e. those customers that have obtained the exemption shall retain it subject to the re-evaluation described in this Section F). This deferral sub-account shall reflect the difference in distribution delivery charges and CTC charges that the customer(s) would have paid under the applicable standard service classification under former Rule 12 versus what they actually pay. For this calculation, the avoided demand in kW and monthly energy in kWh shall be determined as follows: (i) in the event a meter exists on the OSG, the customer will supply to the Company the appropriate kW and kWh determinants, or (ii) if no meter exists on the OSG, the customer will supply to the Company the number of hours that the OSG actually operated during the month. For this purpose, the monthly peak generation in kW shall be set at the nameplate capacity as set forth in Form G and the monthly generation in kWh shall be the product of the nameplate capacity in kW times the operating hours. If the number of operating hours are not provided, the customer and the Company shall set forth in Form G an agreed upon expected monthly generation in kWh.

G. Small Residential PV Systems
Standby service rates shall not apply to residential customers with photovoltaic generating systems rated at 10.0 kW or less provided they have executed a Form F Agreement with the Company.

H. Emergency Generators
Customers who install an Emergency Power (as defined in Rule 1.6) may be exempted from the requirement of service under this S.C. No. 7 if the customer commits in a written agreement with the Company that the on-site generators shall be subject to all of the following requirements:

1) Each such OSG shall be designated in the customer's Standby Service Application with the Company as an Emergency Power System ("Emergency OSG") pursuant to Rules 1.50;
2) Each such Emergency OSG is not capable of being operated in parallel with the Company's system other than for closed-transition transfer switching where the term "closed-transition transfer" is characterized as a momentary make-before-break switching sequence.

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3) Each such Emergency OSG is connected to the customer's electric system using an automated or manual transfer switch or the electrical equivalent of such a switch approved by the Company.

4) The Emergency OSG is used exclusively for purposes of Emergency Power System (defined in Rule 1.6.

5) No load may be served by Emergency OSG while Electric Service is being provided by the Company to the premises except:

(i) for the periods of time as required by statute or regulation, and
(ii) in the absence of a statutory or regulatory requirement, such times so as to adequately test such systems, not to exceed 10 hours per month or as otherwise agreed to by the Company in the Standby Service Application, and
(iii) for periods of time called by the NYISO for EDRP or ICAP(UCAP).

6) The customer shall maintain an operating log for each Emergency OSG indicating the date, time, hours, and purpose of each operation of each such facility. This log shall be made available to the Company upon request. If the customer fails to maintain this log or to provide it to the Company on request, the Company shall have the following rights:

(i) to bill the customer for those amounts of Electric Service which the Company reasonably estimated were inappropriately supplied by the customer's generator during times when Electric Service from the Company was available to the customer; and

In all cases, the customer shall remain obligated to execute and have the Company accept a Standby Service Application as applicable under the special provisions of the applicable service classification for all Emergency Generators on the premises. The customer shall state its intended use of the OSG facilities on the Standby Service Application in the blank spaces provided for special conditions.

I. Customers served on SC-2D with a contract demand less than 50 kW that elect to remain on the SC-2D standard service classification.

SERVICE CLASSIFICATION NO. 7 (Continued)

APPLICATION FOR SERVICE:

The customer must apply for service by providing the Company with an executed Form G, Application For Electric Standby Service and interconnection agreement, both of which are available from Company representatives. Customers operating an on-site generator unit less than 300.0 kVA may use the Company's Form K Interconnection Agreement. Customer's in excess of 300.0 kVA must execute an interconnection agreement.

C□ARACTER OF SERVICE:

Single or three phase alternating current, approximately 60 hertz, at a single standard delivery voltage with service metered at, or compensated to, that delivery point. Site-specific requirements will be determined by the Company.

BILLING PARAMETERS:

Customers served under this service classification shall be billed according to the following parameters:

Customer Charge - a charge for customer related services.

Incremental Customer Charge - the incremental cost of metering and meter communications equipment necessary to administer this Standby Service.

Standby Contract Customer Charge - a reservation charge for the use of the Company's local distribution system (applicable only to standby service customers that would otherwise be served under S.C. No. 1, S.C. No. 2 Non-demand).

Standby Contract Demand Charge - a reservation charge for the use of the Company's local distribution system.

As Used On-Peak Daily Demand Charge - a daily usage demand charge for the maximum use of the Company's delivery system during on-peak hours (as defined herein).

As Used Daily Energy Charge - an energy based usage charge for use of the Company's delivery system (applicable only to standby service customers that would otherwise be served under S.C. No. 1 and S.C. No. 2 Non-demand).

Electricity Supply Service Charge - a charge for the electricity supply service (Commodity) provided to the customer.

Surcharges and Adjustments - a set of itemized charges for specific adjustments as provided under the otherwise applicable service classification.

RATES:

Rates are established on a calendar month basis and will only be prorated if the billing period is less than 25 days or more than 35 days.

SERVICE CLASSIFICATION NO. 7 (Continued)

Applicable Rates and Charges

SERVICE CLASSIFICATION NO. 1 - Residential

MONT□LY RATE:	
Customer Charge:	$14.92
Competitive Transition Charge	
Load Zones A, B	$ 2.60
Load Zones C, D, E	$ 2.09
Load Zone F	$ 1.24
Metering and Communications/Incremental Customer Charge	
All Zones	Leaf No. 106-F (A-E)
Contract Customer Charge:	
Distribution Delivery	$14.45
Competitive Transition Charge	
Load Zones A, B	$2.52
Load Zones C, D, E	$2.03
Load Zone F	$1.20
As Used Daily Energy Charges, Per k□ h:	
Distribution Delivery	$0.01015
Competitive Transition Charge	
Load Zones A, B	$0.00177
Load Zones C, D, E	$0.00142
Load Zone F	$0.00084

SERVICE CLASSIFICATION NO. 2ND

MONT□LY RATE:	
Customer Charge:	$19.13
Competitive Transition Charge	
Load Zones A, B	$10.35
Load Zones C, D, E	$ 9.62
Load Zone F	$ 8.44
Metering and Communications/Incremental Customer Charge	
All Zones	Leaf No. 106-F (A-E)
Standby Contract Customer Charge	
Distribution Delivery	$11.65
Competitive Transition Charge	
Load Zones A, B	$ 6.30
Load Zones C, D, E	$ 5.86
Load Zone F	$ 5.14
As Used Daily Energy Charges, Per k□ h:	
Distribution Delivery	$0.01058
Competitive Transition Charge	
Load Zones A, B	$0.00572
Load Zones C, D, E	$0.00532
Load Zone F	$0.00467

SERVICE CLASSIFICATION NO. 7 (Continued)

<u>SERVICE CLASSIFICATION NO. 2D (No Interval Meter)</u>

MONT□LY RATE:	
Customer Charge:	$47.25
Competitive Transition Charge	
Load Zones A, B	$31.97
Load Zones C, D, E	$29.26
Load Zone F	$24.23
Metering and Communications/Incremental Customer Charge:	
All Load Zones	Leaf No. 106-F (A-E)
Contract Demand Charge, per k□ :	
Distribution Delivery	$ 3.95
Competitive Transition Charge	
Load Zones A, B	$ 2.67
Load Zones C, D, E	$ 2.45
Load Zone F	$ 2.03
As-Used Daily Energy Charges, Per k□ h:	
Distribution Delivery	$.01322
Competitive Transition Charge	
Load Zones A, B	$.00895
Load Zones C, D, E	$.00819
Load Zone F	$.00678

<u>SERVICE CLASSIFICATION NO. 2D (Interval Meter)</u>

MONT□LY RATE:	
Customer Charge:	$47.25
Competitive Transition Charge	
Load Zones A, B	$31.97
Load Zones C, D, E	$29.26
Load Zone F	$24.23
Metering and Communications/Incremental Customer Charge:	
All Load Zones	Leaf No. 106-F (A-E)
Contract Demand Charge, per k□	
Distribution Delivery	$3.95
Competitive Transition Charge	
Load Zones A, B	$2.67
Load Zones C, D, E	$2.45
Load Zone F	$2.03
As-Used On-Peak Daily Demand Charges, Per k□ :	
Distribution Delivery	$0.2986
Competitive Transition Charge	
Load Zones A, B	$0.2020
Load Zones C, D, E	$0.1849
Load Zone F	$0.1531

Whenever Company does not have to supply and maintain a transformer or transformers for such service there shall be a discount of ninety cents per kW per month for each kW of billed demand, applicable to the demand charge stated under Standby Contract Distribution Demand Charge.

SERVICE CLASSIFICATION NO. 7 (Continued)

SERVICE CLASSIFICATION NO. 3

MONT□LY RATE:

Customer Charge:				
Delivery Voltage	0-2.2 kV	2.2-15 kV	22-50 kV	Over 60 kV
Distribution Delivery Charge:	$260.15	$436.70	$554.83	$599.15
Competitive Transition Charge				
Load Zones A, B	$405.85	$828.69	$2,344.67	$1,867.06
Load Zones C, D, E	$369.81	$787.99	$2,284.80	$2,315.18
Load Zone F	$343.46	$697.53	$2,052.30	$2,052.64
Metering and Communications/Incremental Customer Charge:				
All Load Zones	Leaf No. 106-F (A-E)			

Contract Demand Charges, Per k□ :

Delivery Voltage	0-2.2 kV	2.2-15 kV	22-50 kV	Over 60 kV
Distribution Delivery	$3.95	$3.44	$1.18	$0.89
Competitive Transition Charge				
Load Zones A, B	$ 6.16	$6.53	$4.97	$2.79
Load Zones C, D, E	$ 5.61	$6.21	$4.84	$3.46
Load Zone F	$ 5.21	$5.50	$4.35	$3.07

As-Used On-Peak Daily Demand Charges, Per k□ :

Delivery Voltage	0-2.2 kV	2.2-15 kV	22-50 kV	Over 60 kV
Distribution Delivery	$0.2178	$0.1711	$0.0800	$0.0830
Competitive Transition Charge				
Load Zones A, B	$0.3397	$0.3247	$0.3381	$0.2587
Load Zones C, D, E	$0.3096	$0.3088	$0.3294	$0.3208
Load Zone F	$0.2875	$0.2733	$0.2959	$0.2844

Plus Reactive Demand Charges:

All Delivery Voltages: $0.85 for each chargeable RkVA of lagging reactive demand.

Tenth Revised Leaf No. 106-A
Superseding Ninth " Leaf No. 106-A

SERVICE CLASSIFICATION NO. 7 (Continued)

SERVICE CLASSIFICATION NO. 3A

MONT□LY RATE:
Customer Charge:

Delivery Voltage	0-2.2 kV	2.2-15 kV	22-50 kV	Over 60 kV
Distribution Delivery Charge:	$902.00	$902.00	$1,400.00	$3,172.00
Competitive Transition Charge				
Load Zones A, B	$1,240.93	$669.86	$4,144.04	$10,333.76
Load Zones C, D, E	$1,157.67	$612.74	$3,952.08	$ 9,940.03
Load Zone F	$1,023.12	$523.93	$3,575.73	$ 8,964.67

Metering and Communications/Incremental Customer Charge:
All Load Zones Leaf No. 106-F (A-E)

Contract Demand Charges, Per k□ :

Delivery Voltage	0-2.2 kV	2.2-15 kV	22-50 kV	Over 60 kV
Distribution Delivery	$2.99	$3.12	$0.44	$0.27
Competitive Transition Charge				
Load Zones A, B	$4.11	$2.32	$1.30	$0.89
Load Zones C, D, E	$3.83	$2.12	$1.24	$0.85
Load Zone F	$3.39	$1.81	$1.12	$0.77

As-Used On-Peak Daily Demand Charges, Per k□ :

Delivery Voltage	0-2.2 kV	2.2-15 kV	22-50 kV	Over 60 kV
Distribution Delivery	$0.1628	$0.2713	$0.1328	$0.1154
Competitive Transition Charge				
Load Zones A, B	$0.2240	$0.2015	$0.3931	$0.3759
Load Zones C, D, E	$0.2089	$0.1843	$0.3749	$0.3616
Load Zone F	$0.1847	$0.1576	$0.3392	$0.3261

Plus Reactive Demand Charges:

All Delivery Voltages: $1.02 for each chargeable RkVA of lagging reactive demand.

SERVICE CLASSIFICATION NO. 7 (Continued)

All SERVICE CLASSIFICATION NUMBERS:
Electricity Supply Service:

Company Supplied Electricity Supply Service Charges, per k□ h:

Company supplied Electricity Supply Service charges shall be set according to the market price of electricity determined in accordance with Rule 46, Electricity Supply Cost.

Customers served under this Service Classification No. 7 are also eligible to participate in Rule No. 39 - Retail Access Program.

SURC□ARGES AND ADJUSTMENTS

System Benefits Charge:

Customers served under this Service Classification No. 7 shall be subject to the Rule 41 - System Benefits Charge for the parent service classification.

Delivery Charge Adjustment:

Customers served under this Service Classification No. 7 shall be not eligible for Rule 29 Delivery Charge Adjustment.

Transmission Revenue Adjustment Charge:

Customers served under this Service Classification No. 7 shall be subject to the Rule 43 - Transmission Revenue Adjustment for the parent service classification.

Customer Service Backout Credit:

Customers who obtain their Electricity Supply Service from an ESCo are eligible for Rule 42 - Customer Service Backout Credit Mechanism for the respective parent service classification.

MINIMUM C□ARGE:

Customers served under this Service Classification No. 7 shall be subject to a minimum Charge which shall be the Customer Charge, the Incremental Customer Charge (where applicable), the Standby Contract Demand Charge and the Competitive Transition Charge.

INCREASE IN RATES AND C□ARGES:

The rates and charges under this Service Classification, including the Minimum Charge, will be increased by a tax factor pursuant to Rule 32.

TERMS OF PAYMENT:

Bills are due and payable when rendered. Full payment must be received on or before the date shown on the bill to avoid a late payment charge pursuant to Rule 26.4.

SERVICE CLASSIFICATION NO. 7 (Continued)

TERM:

One year from commencement of service hereunder and continuously thereafter until permanently canceled by the customer upon 90 days' prior notice to the Company.

DETERMINATION OF DEMAND:

(1) Standby Contract Demand

Standby Contract Demand shall initially be set at the maximum anticipated demand of the customer including any load that is not isolated pursuant to Rule 1.48 codified in a Standby Service Application and determined as the greater of the following and the Company shall inform the customer of the resultant contract demand ten (10) days prior to the next billing cycle:

(i) the maximum demand from the Company's system over the previous 12-months, or

(ii) the customer's maximum load supplied by all sources including the OSG and Company's supply system over the previous 12-months.

In the case of a new customer (i.e., a customer for whom historical consumption data does not exist) the Standby Contract Demand shall be the maximum anticipated demand of load consumed as a National Electrical Code calculation in effect based upon the electrical equipment to be served.

The Standby Contract Demand shall automatically be increased to the highest measured demand in any billing period during the term hereunder.

The Standby Contract Demand of a Wholesale Generator who is connected to a customer which would otherwise be served directly by the Company shall be set at the maximum potential demand of the station loads of the Wholesale Generator when the generator is out of service plus the maximum potential demand of the customer connected to the Wholesale Generator.

The Standby Contract Demand may be increased based upon a written notice by the customer to the Company at any time.

The Standby Contract Demand as determined above may be reduced based upon a written notice by the customer to the Company and may be reduced no more than one time in a 365-day period and/or 365 days from any increase or ratchet in Contract Demand. In the event the customer's Standby Contract Demand is reduced thereafter and the recorded maximum demand at any time exceeds the customer's nominated and effective Standby Contract Demand: (i) by 20% or greater then a penalty equal to the product of 24 times the contract demand rate times the demand in excess of the Standby Contract Demand shall apply, (ii) by 10% or greater, but less than 20%, then a penalty equal to the product of 18 times the contract demand rate times the demand in excess of the Standby Contract Demand shall apply, (iii) by less than 10% then a penalty equal to the product of 12 times the contract demand rate times the demand in excess of the Standby Contract Demand shall apply. Seasonal or other temporary fluctuations in load of the customer's existing facilities such as heating and air conditioning, and temporary reductions in manufacturing shall not qualify for reductions in the Standby Contract Demand.

The effective date of the revised Standby Contract Demand shall be the next billing cycle following the Company's receipt of the customer's written notice provided such notice is received 10 business days prior to the first day of the next billing cycle.

SERVICE CLASSIFICATION NO. 7 (Continued)

DETERMINATION OF DEMAND and CONTRACT ENERGY: (Continued)

(2) As-Used Daily Demand

The As-Used Daily Demand shall be the aggregate of the highest daily 15-minute integrated demand (measured in kW) occurring during the on-peak hours of each day during the billing period.

On-Peak hours are defined as the hours between 8:00 a.m. and l0:00 p.m., Mondays through Fridays, except for the following holidays when such holidays fall on other than a Saturday or Sunday: New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day, and Christmas Day. All other hours are defined as Off-Peak.

(3) As-Used Daily Energy

The As-Used Daily Energy shall be determined as the sum of the billed kWh in the billing period.

(4) The Reactive Demand

The Reactive Power Demand Charge shall be the highest average kilovolt-ampere of lagging reactive demand measured in a fifteen minute interval during the month less one-third of the highest kilowatt demand measured during the month.

SERVICE CLASSIFICATION NO. 7 (Continued)

INTERCONNECTION RE□UIREMENTS:

The facility may be connected for parallel operation with the service of the Company, or isolated for operation with standby service provided by a Wholesale Generator by means of a double throw transfer switch or transfer switching scheme acceptable to the Company.

Customers are required to execute an Interconnection Agreement with the Company. Customers having an on-site generator in aggregate with other OSG's of less than 300 kVA are eligible to execute a Form K Interconnection Agreement.

All other customers must execute an Interconnection Agreement, available from Company representatives.

For parallel generator installations, the customer and the Company shall agree as to the operating mode, interconnection and equipment specifications as set forth in Specifications for Electrical Installations Supplement, Electric System Bulletin Nos. 756A or 756B as applicable and as amended from time to time, which is subject to Commission review and arbitration should a dispute arise.

The following provision shall not apply to Wholesale Generators that agree to pay for actual interconnection costs in Interconnection Agreements or other agreements with the Company. The customer shall agree to pay for all interconnection costs which exceed the costs ordinarily incurred in rendering service at the same Standby Contract Demand under the applicable Service Classification. Upon a mutual agreement the customer may select from the following payment options, provided that upon request, the customer agrees to provide a compensatory letter of credit to the Company:

(1) The Company will furnish, own, operate, and maintain all special equipment, in return for which the customer, or its successors on the site, will pay a monthly charge of 1.5 percent of the total investment costs for the duration of its/their operations on the site, whether or not the equipment is in use.

(2) The customer will furnish, own, and operate all special equipment on their property and the Company will maintain such equipment, in return for which the customer, or its successors on the site, will pay a 9 percent annual operating charge based upon the customer's total investment in such interconnection equipment.

(3) The customer will furnish, own, operate and maintain all special equipment on their property provided that the equipment and maintenance are suitable for interconnected operations. Such equipment shall be made available for Company inspection as may reasonably be required.

SERVICE CLASSIFICATION NO. 7 (Continued)

METERING AND COMMUNICATIONS/INCREMENTAL CUSTOMER C□ARGE

A. Interval Metering : All electricity load measurement for customers 50 kW or larger shall utilize the Company's interval recording meter at the Customer Premises. Where an interval-recording meter does not exist and must be installed, the customer shall be responsible for all metering and installation costs not otherwise covered by New York State Research and Development Authority (NYSERDA). The metering costs are a function of the individual customer's electric service. Metering and installation cost estimates are available from Company representatives. The customer is responsible for the actual costs incurred. Customers who have already installed the requisite interval recording meters as of the effective date of this Service Classification No. 7 will not be subject to incremental metering costs.

B. Telecommunications: Remote meter reading capability is also required for customers 50 kW or larger. The customer will be responsible for all costs associated with providing the telecommunications to the meter. The customer may choose to either:

1) provide the Company access to a direct-dial, voice-grade, Public Switched Telephone Network analog connection to the meter, subject to Company approval, to be used exclusively for meter reading functions; or
2) the Company will provide communications to the meter at a cost to the customer including applicable overhead.

Customers who have already installed the requisite remote meter reading capability as of the effective date of this Service Classification No. 7 will not be subject to incremental metering costs.

C. Customer-Provided Equipment: Customers providing a telephone connection to the meter will bear all costs associated with the installation, operation and maintenance of the telephone line including, but not limited to, all telephone service bills.

In cases where the Company is unable to read the meter through a customer-provided telephone line, and the Company has determined that the problem is not caused by the Company's meter or equipment, the customer will be responsible to resolve the problem with its telephone provider and will be responsible to reimburse the Company for expenses incurred for visits to the meter location in its efforts to resolve the problem.

D. Company-Provided Equipment: Customers who choose the Company-provided meter reading communication option shall pay a monthly Incremental Customer Communications Charge as set forth in a schedule provided by the Company. Company-provided communications will be used exclusively for meter reading functions.

E. Exceptions for Customers Smaller Than 50 kW: Notwithstanding the foregoing, customers who would otherwise receive service under S.C. No. 1and S.C. No. 2 Non-Demand will not be required to install interval meters and as such will not be subject to any additional metering and communication charges. In addition customers who would otherwise receive service under S.C. No. 2 Demand, who have Standby Contract Demands less than 50 kW will have the option of taking service at either (i) the otherwise applicable demand rate and shall not be subject to any additional metering and communication charges under S.C-7; or (ii) upon installation of required interval metering, the demand rate set forth under S.C.-7.

SERVICE CLASSIFICATION NO. 7 (Continued)

SPECIAL PROVISIONS

A. Standby Demands Larger Than 1000 kW: All customers with Standby Contract Demands greater than 1000 kW applying for Service under this Service Classification are required to provide the Company with an annual schedule of OSG maintenance by October of the preceding year for each subsequent year. This schedule will be provided at the time of subscription to this Service Classification and will be utilized for planning functions. Schedules must include starting and ending times for all planned outages. Customers will be allowed to update their schedules one month prior to their effective dates. After this time has passed, no modifications will be allowed to the schedules, unless Company approval is granted. This provision does not take precedence with respect to any OSG maintenance provision in a power purchase agreement which may be in place with the Company.

B. SC-4 Customers: Customers who would otherwise receive service under the provisions of Service Classification No. 4 shall have their demand measured on an integrated 30 minute basis, pursuant to the terms of that tariff.

C. Compliance With Reliability Criteria: Customer agrees to comply with any existing or future criteria, guidelines, and procedures established by the North American Electric Reliability Council (or its successor) to ensure the continued reliability of North America's interconnected secured transmission electric systems.

D. Electrically Isolated Loads: In the event that any customer elects to Electrically Isolate (as defined in Rule 1.48) some or all of the facilities at the Customer's Location and to thereafter serve such facilities with electricity from on-site generation without connection to the Company's system, the isolated portion of that customer's load will not be subject to S.C. No. 7 provided that the customer executes an agreement with the Company that provides for the following:

The Company will be entitled to inspect the electrical configuration of such facilities upon a customer's request for this exemption.

SERVICE CLASSIFICATION NO. 7 (Continued)

SPECIAL PROVISIONS:

D. (Continued)

If at any time, the Company has a reasonable suspicion that such facilities have not remained isolated from the Company's system, the Company is authorized to inspect the electrical configuration of such facilities.

If the Company discovers, through billing data and/or the inspection of the customer's facilities, that any of the facilities for which an isolation exemption had been applied have been reconnected to the Company's system, the Company will back bill the customer for the isolated load under S.C. No. 7 from the effective date of the customer's reconnection, including applicable interest and penalties. Such back billing will be computed in the same manner as described under Special Provision E.

E. Penalties for Reconnecting Isolated Loads Without Notice: Notwithstanding any other provision of this Tariff, in the event that the customer connects on-site generation to its electric system without: (1) notifying the Company; and (2) executing a Standby Service Application (Form G), and in the event that the Company thereafter discovers that fact, the Company shall back-bill the customer for all service rendered subsequent to the estimated installation of such on-site generation.

In preparing such back-bills, the Company shall assess a Standby Demand Penalty Provision equal to 2 times that which would otherwise be computed under Determination of Demand Provision of this Service Classification No. 7 and assume the Standby Contract Demand had been set at 0 kW. If the customer fails to pay the undisputed portion of any such back-bill within the time for payment of bills established in this S.C. No. 7, the Company shall be authorized to exercise all of its rights in cases involving theft of service, including without limitation its rights under Rule 13.3 (a)(2) of the Commission Rules and Rule 14.4 of this Tariff.

Third Revised Leaf No. 106-I
Superseding Second " Leaf No. 106-I

SERVICE CLASSIFICATION NO. 7 (Continued)

SPECIAL PROVISIONS:

F. Reduced Customer Charge for Certain Wholesale Generators

SC-7 customers who are Wholesale Generators who:

(a) have a parent service classification of SC-3 or SC-3A and are served at the subtransmission or transmission voltage level and

(b) have paid for all of their interconnection facilities as defined in the applicable filed interconnection agreement (or have arranged for payment by an entity other than the Company) and metering equipment, and pay the Company ongoing operation and maintenance costs for that equipment (or have arranged for payment by an entity other than the Company) shall pay a customer charge in lieu of the otherwise applicable customer charge, including the customer charge, CTC, equal to the following:

SC-3 Customer Charge

	Sub-Transmission	Transmission
Delivery Voltage	22-50 kV	Over 60 kV
Distribution Delivery Charge:	$172.82	$186.62
Competitive Transition Charge		
Load Zones A, B	$730.31	$581.54
Load Zones C, D, E	$711.66	$721.12
Load Zone F	$639.24	$639.35

SC-3A Customer Charge

	Sub-Transmission	Transmission
Delivery Voltage	22-50 kV	Over 60 kV
Distribution Delivery Charge:	$436.07	$988.00
Competitive Transition Charge		
Load Zones A, B	$1290.77	$3218.71
Load Zones C, D, E	$1230.98	$3096.08
Load Zone F	$1113.75	$2792.27

SERVICE CLASSIFICATION NO. 7 (Continued)

SPECIAL PROVISIONS:

G. Billing for Customers With OSG's Smaller Than 15% of Maximum Potential Demand: Customers that install an OSG that is less than 15% of their maximum potential demand over the previous 12 months shall be subject to the delivery charges of this Service Classification No. 7 and the delivery charges of the otherwise applicable service classification. Standby service and the otherwise applicable service classification billing determinants shall be determined as follows:

The Standby Service Billing Determinants:
The Standby Contract Demand shall be determined as the nameplate generating capacity of the OSG (in the case of multiple generators the Standby Contract Demand shall be determined as the sum of the nameplate generating capacities).

The As-Used Daily Demand shall be determined as the nameplate generating capacity of the OSG multiplied by the number of on-peak days in the billing period multiplied by the standby service ratio. The standby service ratio shall be defined as the quotient of the nameplate generating capacity divided by the maximum demand occurring over the last 12 billing periods.

SERVICE CLASSIFICATION NO. 7 (Continued)

SPECIAL PROVISIONS:

G. (Continued)

The Otherwise Applicable Billing Determinants:
The billing determinants of the otherwise applicable service classification shall be determined in accordance with the provisions of that otherwise applicable tariff and adjusted as follows:

Demand charges assessed on a maximum demand shall be reduced by the nameplate generating capacity of the OSG. In the case of customers that would otherwise receive service under SC-3A, the maximum demand (used for distribution delivery) and the maximum on-peak demand (used for the assessment of competitive transition charges) shall be reduced by the nameplate capacity of the OSG.

All energy under this Special Provisions shall be served under Rule No. 46 – Electricity Supply Cost with no application of Rule No. 29 – Delivery Charge Adjustment.

H. Waiver of Reactive Demand Charges for Wholesale Generators Larger Than 25 MVA and With Automatic Voltage Control: For customers who operate a Wholesale Generator in larger than 25 MVA and install automatic voltage control (AVC) at their facilities, reactive demand charges shall be waived, within the parameters defined by the Company during the period in which such AVC is operating and maintained in good working order. The Company shall not waive start-up reactive demand charges. The initial parameters will be determined by the Company and may be changed subject to system conditions and location of the generating unit. The waiver is subject to the Company's rights to periodically review and approve the customer's AVC system and review its operation and performance for compliance with the system requirements.

JOINT PROPOSAL

ATTACHMENT 2

Lost Revenue Deferral and Rate Adjustment

Illustration of Lost Revenue Deferral and Rate Adjustment
(Dollars)

		2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
	Fcast Annual Lost Revenues Relative to 2002										
1.	January - June	$ -	$ -	$ 437,500	$ 437,500	$ 3,333,333	$ 3,333,333	$ 12,600,000	$ 12,600,000	$ 17,500,000	$ 17,500,000
2.	July - December	$ -	$ 437,500	$ 437,500	$ 437,500	$ 3,333,333	$ 3,333,333	$ 12,600,000	$ 12,600,000	$ 17,500,000	$ 17,500,000
3.	Total	$ -	$ 437,500	$ 875,000	$ 875,000	$ 6,666,667	$ 6,666,667	$ 25,200,000	$ 25,200,000	$ 35,000,000	$ 35,000,000
	Actual Annual Lost Revenues Relative to 2002										
4.	January - June	$ 291,667	$ 437,500	$ 500,000	$ 3,333,333	$ 8,400,000	$ 12,600,000	$ 13,650,000	$ 17,500,000	$ 17,500,000	$ 17,500,000
5.	July - December	$ 583,333	$ 875,000	$ 1,000,000	$ 6,666,667	$ 12,600,000	$ 13,650,000	$ 16,975,000	$ 17,500,000	$ 17,500,000	$ 17,500,000
6.	Total	$ 875,000	$ 1,312,500	$ 1,500,000	$ 10,000,000	$ 21,000,000	$ 26,250,000	$ 30,625,000	$ 35,000,000	$ 35,000,000	$ 35,000,000

	1st CTC reset @ 1/04 done at 8/03				3rd CTC reset @ 1/08 done at 8/07				Amount to be recovered after 2011		
7.	Actuals	1/02-6/02	$ 291,667		Fcst	1/08-12/09	$ 50,400,000		+ Reconciliation Actuals vs Forecast Prior Periods		
8.		7/02-12/02	$ 583,333		(amount based on actual 1/07-6/07 * 4)						
9.		1/03-6/03	$ 437,500							7/09-12/09	$ 4,900,000
10.					+ Reconciliation Actuals vs Forecast Prior Periods					1/10-6/10	$ -
11.	+ Fcst	7/03-12/05	$ 2,187,500							7/10-12/10	$ -
12.	(amount based on actual 1/03-6/03 * 5)					7/05-12/05	$ 6,229,167			1/11-6/11	$ -
13.						1/06-6/06	$ 5,066,667			7/11-12/11	$ -
14.						7/06-12/06	$ 9,266,667				
15.						1/07-6/07	$ 9,266,667				
16.	Total to be used for revenue collection		$ 3,500,000	over 2 yrs	Total to be used for revenue collection		$ 80,229,167	over 2 yrs	Total to be recovered post 2011		$ 4,900,000
									See NOTE below		

	2nd CTC reset @ 1/06 done at 8/05				4th CTC reset @ 1/10 done at 8/09			
17.	Fcst	1/06-12/07	$ 13,333,333		Fcst	1/10-12/11	$ 70,000,000	
	(amount based on actuals 1/05-6/05 * 4)				(amount based on actual 1/09-6/09 * 4)			
	+ Reconciliation Actuals vs Forecast Prior Periods				+ Reconciliation Actuals vs Forecast Prior Periods			
18.		7/03-12/03	$ 437,500			7/07-12/07	$ 10,316,667	
19.		1/04-6/04	$ 62,500			1/08-6/08	$ 1,050,000	
20.		7/04-12/04	$ 562,500			7/08-12/08	$ 4,375,000	
21.		1/05-6/05	$ 2,895,833			1/09-6/09	$ 4,900,000	
22.	Total to be used for revenue collection		$ 17,291,667	over 2 yrs	Total to be used for revenue collection		$ 90,641,667	over 2 yrs

23.	Total recovered	1st CTC reset	$ 3,500,000
24.		2nd CTC reset	$ 17,291,667
25.		3rd CTC reset	$ 80,229,167
26.		4th CTC reset	$ 90,641,667
27.		after 2011	$ 4,900,000
28.		Total	$ 196,562,500
29.	vs actual lost revenues shown in line 6		$ 196,562,500

NOTE: Any remaining Standby Lost Revenue Deferral Account balance at end of Merger Rate Plan shall be transferred to Merger Deferral Acccount

Illustration of Merger Joint Proposal Deferral Credit
(Dollars)

	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
Fcast Annual Lost Revenues Relative to 2002										
1. January - June	$ -	$ -	$ 437,500	$ 437,500	$ 3,333,333	$ 3,333,333	$ 12,600,000	$ 12,600,000	$ 17,500,000	$ 17,500,000
2. July - December	$ -	$ 437,500	$ 437,500	$ 437,500	$ 3,333,333	$ 3,333,333	$ 12,600,000	$ 12,600,000	$ 17,500,000	$ 17,500,000
3. Total	$ -	$ 437,500	$ 875,000	$ 875,000	$ 6,666,667	$ 6,666,667	$ 25,200,000	$ 25,200,000	$ 35,000,000	$ 35,000,000
Actual Annual Lost Revenues Relative to 2002										
4. January - June	$ 291,667	$ 437,500	$ 500,000	$ 3,333,333	$ 8,400,000	$ 12,600,000	$ 13,650,000	$ 17,500,000	$ 17,500,000	$ 17,500,000
5. July - December	$ 583,333	$ 875,000	$ 1,000,000	$ 6,666,667	$ 12,600,000	$ 13,650,000	$ 16,975,000	$ 17,500,000	$ 17,500,000	$ 17,500,000
6. Total	$ 875,000	$ 1,312,500	$ 1,500,000	$ 10,000,000	$ 21,000,000	$ 26,250,000	$ 30,625,000	$ 35,000,000	$ 35,000,000	$ 35,000,000
7. Merger Joint Proposal Section 1.2.4.17 Offset	$ -	$ (667,000)	$ (2,000,000)	$ (2,000,000)	$ (2,000,000)	$ (2,000,000)	$ (2,000,000)	$ (2,000,000)	$ (2,000,000)	$ (2,000,000)
8. Rule 44 and 52 Annual Lost Revenues	$ -	$ 100,000	$ 200,000	$ 300,000	$ 400,000	$ 500,000	$ 600,000	$ 700,000	$ 800,000	$ 900,000
9. Net Section 1.2.4.17 Offset Available	$ -	$ (567,000)	$ (1,800,000)	$ (1,700,000)	$ (1,600,000)	$ (1,500,000)	$ (1,400,000)	$ (1,300,000)	$ (1,200,000)	$ (1,100,000)
10. Actual Annual Lost Revenues Relative to 2002	$ 875,000	$ 1,312,500	$ 1,500,000	$ 10,000,000	$ 21,000,000	$ 26,250,000	$ 30,625,000	$ 35,000,000	$ 35,000,000	$ 35,000,000
11. Merger Joint Proposal Deferral Credit	$ -	$ (567,000)	$ (1,500,000)	$ (1,700,000)	$ (1,600,000)	$ (1,500,000)	$ (1,400,000)	$ (1,300,000)	$ (1,200,000)	$ (1,100,000)

1. Illustrative Forecasted Lost Revenues
2. Illustrative Forecasted Lost Revenues
3. Line 1 + Line 2
4. Illustrative Actual Lost Revenues
5. Illustrative Actual Lost Revenues
6. Line 4 + Line 5
7. Merger Joint Proposal Section 1.2.4.17, p. 24
8. Illustrative Rule 44 and 52 Lost Revenues
9. Line 8 - Line 9
10. Line 6
11. For All but 2003, MIN(MAX(Line 9, -Line 10)); For 2003, MIN(MAX(Line 9, -Line 5 * 2 / 3))

A:\[Standby Rates Deferral Account JP020312.xls]Revenues
03/11/2002

Niagara Mohawk Power Corporation
Case 01-E-1847 Joint Proposal 03/12/02
Attachment 2
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Illustrative Allocation and Design of Lost Standby Service Revenue Rate Adjustment

	Service Class	Merger Delivery Allocator Excl. PSC 214	Illustrative Deferral Allocation	Illustrative Next Two Years Forecasted kWh	Illustrative Rate Adjustment per kWh
1.	SC-1	44.030%	$ 1,541,038	18,623,816,000	$ 0.00008
2.	SC-1B	0.307%	$ 10,743	213,454,240	$ 0.00005
3.	SC-1C	1.458%	$ 51,025	982,323,760	$ 0.00005
4.	SC-2ND	4.083%	$ 142,904	1,399,930,000	$ 0.00010
5.	SC-2D	16.123%	$ 564,305	8,482,856,567	$ 0.00007
	SC-3				
6.	Secondary	16.770%	$ 586,947	8,960,053,714	$ 0.00007
7.	Primary	5.996%	$ 209,844	3,910,865,210	$ 0.00005
8.	Subtransmission	1.146%	$ 40,115	911,973,572	$ 0.00004
9.	Transmission	0.167%	$ 5,847	129,176,822	$ 0.00005
10.	Total	24.079%		13,912,069,318	
	SC-3A				
11.	Secondary	0.746%	$ 26,122	670,181,912	$ 0.00004
12.	Primary	1.470%	$ 51,440	1,666,087,944	$ 0.00003
13.	Subtransmission	3.118%	$ 109,131	4,343,110,168	$ 0.00003
14.	Transmission	4.587%	$ 160,540	7,285,762,090	$ 0.00002
15.	Total	9.921%		13,965,142,113	
16.	Total PSC 207	100.000%		57,579,591,998	
17.	Revenue Adjustment (p.1, Line 16)		$ 3,500,000		

A:\[Standby Rates Deferral Account JP020312.xls]Revenues
03/11/2002

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Illustrative Calculation of Lost Standby Service Revenue

Revenues That Would Otherwise Be Collected Under Former Rule 12
2002

BILLING UNITS

Rate Class	Bills	Distribution kW	Distribution kWh	CTC kW	Transformer Adjustment kW	rkVA	CTC Energy Block 1 / on-pk kWh	CTC Energy Block 1 / off-pk kWh	CTC Energy Block 2 / on-pk kWh
1. SC-1	-		-				-		
2. SC-1B	-		-				-		
3. SC-1C	-		-				-	-	
4. SC-2ND	-		-				-		
5. SC-2D	180	6,082	1,208,738	6,082	122		1,208,738		
6. SC-3 Sec	360	84,885	29,898,441	84,885		7,456	28,104,535		1,793,906
7. SC-3 Pri	108	35,753	28,623,044	35,753		5,716	28,623,044		2,862,304
8. SC-3 Sub	36	44,060	14,994,547	44,060		20,433	14,994,547		899,673
9. SC-3 Tran	36	44,060	14,994,547	44,060		20,433	14,994,547		899,673
10. SC-3A Sec	12	44,031	20,230,182	44,031		2,045	5,339,554	5,382,442	
11. SC-3A Pri	48	166,663	78,179,455	166,663		65,198	14,775,917	20,404,838	
12. SC-3A Sub	24	57,551	32,228,610	57,551		-	6,494,709	7,685,879	
13. SC-3A Tran	24	142,560	64,082,544	142,560		34,473	17,270,246	17,975,154	

RATES - (2002 Central Zone)

Rate Class	Customer Charge	Distribution Demand Charge	Distribution Energy Charge	CTC Demand Charge	Transformer Adjustment Charge	Reactive Demand Charge	CTC Energy Block 1 / on-pk Charge	CTC Energy Block 1 / off-pk Charge	CTC Energy Block 2 / on-pk Charge
14. SC-1	$ 14.92		$ 0.03635				$ 0.00890		
15. SC-1B	$ 14.92		$ 0.03983				$ -		
16. SC-1C	$ 36.53		$ 0.03616				$ 0.00469	$ -	
17. SC-2ND	$ 19.13		$ 0.03159				$ 0.03325		
18. SC-2D	$ 47.25	$ 8.32	$ 0.00233		$ (0.90)		$ 0.02481		$ -
19. SC-3 Sec	$ 260.15	$ 8.21		$ 6.76		$ 0.85	$ 0.01820		$ 0.00621
20. SC-3 Pri	$ 436.70	$ 6.89		$ 5.80		$ 0.85	$ 0.02064		$ 0.00827
21. SC-3 Sub	$ 554.83	$ 2.57		$ 6.05		$ 0.85	$ 0.01996		$ 0.00817
22. SC-3 Tran	$ 599.15	$ 2.51		$ 5.72		$ 0.85	$ 0.01909		$ 0.00792
23. SC-3A Sec	$ 902.00	$ 6.50		$ 3.90		$ 1.02	$ 0.02120	$ 0.01550	$ -
24. SC-3A Pri	$ 902.00	$ 8.09	$ 0.00216	$ 0.77		$ 1.02	$ 0.02454	$ 0.01887	$ -
25. SC-3A Sub	$ 1,400.00	$ 2.79		$ 3.40		$ 1.02	$ 0.02605	$ 0.01968	$ -
26. SC-3A Tran	$ 3,172.00	$ 2.26		$ 3.22		$ 1.02	$ 0.02341	$ 0.01789	$ -

REVENUES - (Billing Units * Rates)

Rate Class	Customer Revenues	Distribution Demand Revenues	Distribution Energy Revenues	CTC Demand Revenues	Transformer Adjustment Revenues	Reactive Demand Revenues	CTC Energy Block 1 / on-pk Revenues	CTC Energy Block 1 / off-pk Revenues	CTC Energy Block 2 / on-pk Revenues	Total Revenues
27. SC-1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
28. SC-1B	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
29. SC-1C	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
30. SC-2ND	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
31. SC-2D	$ 8,505	$ 50,602	$ 2,816	$ -	$ (110)	$ -	$ 29,989	$ -	$ -	$ 91,803
32. SC-3 Sec	$ 93,654	$ 696,906	$ -	$ 573,823	$ -	$ 6,338	$ 511,503	$ -	$ 11,140	$ 1,893,363
33. SC-3 Pri	$ 47,164	$ 246,338	$ -	$ 207,367	$ -	$ 4,859	$ 590,780	$ -	$ 23,671	$ 1,120,179
34. SC-3 Sub	$ 19,974	$ 113,234	$ -	$ 266,563	$ -	$ 17,368	$ 299,291	$ -	$ 7,350	$ 723,781
35. SC-3 Tran	$ 21,569	$ 110,591	$ -	$ 252,023	$ -	$ 17,368	$ 286,246	$ -	$ 7,125	$ 694,923
36. SC-3A Sec	$ 10,824	$ 286,202	$ -	$ 171,721	$ -	$ 2,086	$ 113,199	$ 83,428	$ -	$ 667,459
37. SC-3A Pri	$ 43,296	$ 1,348,304	$ 168,868	$ 128,331	$ -	$ 66,502	$ 362,601	$ 385,039	$ -	$ 2,502,940
38. SC-3A Sub	$ 33,600	$ 160,567	$ -	$ 195,673	$ -	$ -	$ 169,187	$ 151,258	$ -	$ 710,286
39. SC-3A Tran	$ 76,128	$ 322,186	$ -	$ 459,043	$ -	$ 35,162	$ 404,296	$ 321,575	$ -	$ 1,618,391
40. TOTAL	$ 354,714	$ 3,334,929	$ 171,684	$ 2,254,544	$ (110)	$ 149,683	$ 2,767,091	$ 941,301	$ 49,287	$ 10,023,123

41. Rule 12 Revenues .... $ 10,023,123

A:\[Standby Rates Deferral Account JP020312.xls]Revenues
03/11/2002

Niagara Mohawk Power Corporation
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Illustrative Calculation of Lost Standby Service Revenue

Standby Service SC-7 Revenues

2002

BILLING UNITS

Rate Class	Bills	Bills	Contract kW	As-Used kWh	As-Used kW	Transformer Adjustment kW	rkVA
1. SC-1	-	-		-			
2. SC-1B	-	-		-			
3. SC-1C	-	-		-			
4. SC-2ND	-	-		-			
5. SC-2D	180		8,441		59,439	122	
6. SC-3 Sec	360		107,871		1,053,904		7,456
7. SC-3 Pri	108		42,643		493,133		5,716
8. SC-3 Sub	36		50,757		567,294		20,433
9. SC-3 Tran	36		66,431		522,120		20,433
10. SC-3A Sec	12		55,596		624,995		2,045
11. SC-3A Pri	48		208,972		2,461,021		65,198
12. SC-3A Sub	24		67,702		835,175		-
13. SC-3A Tran	24		163,240		2,039,859		34,473

RATES - (2002 Central Zone)

Rate Class	Customer Charge	Contract Customer Charge	Contract Demand Charge	As-Used Energy Charge	As-Used Demand Charge	Transformer Adjustment Charge	Reactive Demand Charge
14. SC-1	$ 17.01	$ 16.47		$ 0.01157			
15. SC-1B	$ 17.01	$ 16.47		$ 0.01157			
16. SC-1C	$ 17.01	$ 16.47		$ 0.01157			
17. SC-2ND	$ 28.75	$ 17.50		$ 0.01590			
18. SC-2D	$ 76.51		$ 6.40		$ 0.4834	$ (0.90)	
19. SC-3 Sec	$ 629.96		$ 9.56		$ 0.5273		$ 0.85
20. SC-3 Pri	$ 1,224.69		$ 9.65		$ 0.4799		$ 0.85
21. SC-3 Sub	$ 2,839.63		$ 6.02		$ 0.4094		$ 0.85
22. SC-3 Tran	$ 2,914.33		$ 4.35		$ 0.4038		$ 0.85
23. SC-3A Sec	$ 2,059.67		$ 6.82		$ 0.3717		$ 1.02
24. SC-3A Pri	$ 1,514.74		$ 5.24		$ 0.4556		$ 1.02
25. SC-3A Sub	$ 5,352.08		$ 1.68		$ 0.5077		$ 1.02
26. SC-3A Tran	$ 13,112.03		$ 1.12		$ 0.4770		$ 1.02

REVENUES - (Billing Units * Rates)

Rate Class	Customer Revenues	Contract Customer Revenues	Contract Demand Revenues	As-Used Energy Revenues	As-Used Demand Revenues	Transformer Adjustment Revenues	Reactive Demand Revenues	Total Revenues
27. SC-1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
28. SC-1B	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
29. SC-1C	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
30. SC-2ND	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
31. SC-2D	$ 13,771	$ -	$ 53,999	$ -	$ 28,734	$ (110)	$ -	$ 96,394
32. SC-3 Sec	$ 226,784	$ -	$ 1,031,683	$ -	$ 555,742	$ -	$ 6,338	$ 1,820,546
33. SC-3 Pri	$ 132,266	$ -	$ 411,556	$ -	$ 236,638	$ -	$ 4,859	$ 785,319
34. SC-3 Sub	$ 102,227	$ -	$ 305,408	$ -	$ 232,273	$ -	$ 17,368	$ 657,277
35. SC-3 Tran	$ 104,916	$ -	$ 289,122	$ -	$ 210,815	$ -	$ 17,368	$ 622,221
36. SC-3A Sec	$ 24,716	$ -	$ 379,330	$ -	$ 232,331	$ -	$ 2,086	$ 638,463
37. SC-3A Pri	$ 72,708	$ -	$ 1,095,229	$ -	$ 1,121,242	$ -	$ 66,502	$ 2,355,681
38. SC-3A Sub	$ 128,450	$ -	$ 113,458	$ -	$ 423,980	$ -	$ -	$ 665,888
39. SC-3A Tran	$ 314,689	$ -	$ 183,461	$ -	$ 973,022	$ -	$ 35,162	$ 1,506,334
40. TOTAL	$ 1,120,526	$ -	$ 3,863,247	$ -	$ 4,014,777	$ (110)	$ 149,683	$ 9,148,123

41. Rule 12 Revenues	$ 10,023,123
42. SC-7 Revenues	$ 9,148,123
43. Standby Service Lost Revenues	$ 875,000

Illustration of Standby Service Lost Revenue and Merger Joint Proposal Deferral Mechanisms
(Dollars)

	No Standby or Rule 44 and 52 Deferrals	Standby Deferral > $2M and Various Rule 44 and 52 Deferrals			Standby Deferral < $2M and Various Rule 44 and 52 Deferrals		
	Case No. 1	Case No. 2	Case No. 3	Case No. 4	Case No. 5	Case No. 6	Case No. 7
ORIGINAL MERGER JOINT PROPOSAL DEFERRAL ACCOUNT MECHANISM							
1. Actual Standby Service Lost Revenues	$ -	$ 4,000,000	$ 4,000,000	$ 4,000,000	$ 500,000	$ 500,000	$ 500,000
2. Actual Rule 44 and 52 Lost Revenues	$ -	$ -	$ 1,000,000	$ 3,000,000	$ -	$ 1,000,000	$ 3,000,000
3. Merger Joint Proposal Section 1.2.4.17 Offset	$ -	$ (2,000,000)	$ (2,000,000)	$ (2,000,000)	$ (500,000)	$ (1,500,000)	$ (2,000,000)
4. Merger Joint Proposal Deferral Account	$ -	$ 2,000,000	$ 3,000,000	$ 5,000,000	$ -	$ -	$ 1,500,000
STANDBY SERVICE LOST REVENUE DEFERRAL ACCOUNT MECHANISM							
5. Actual Standby Service Lost Revenues Deferral	$ -	$ 4,000,000	$ 4,000,000	$ 4,000,000	$ 500,000	$ 500,000	$ 500,000
6. Actual Rule 44 and 52 Lost Revenues	$ -	$ -	$ 1,000,000	$ 3,000,000	$ -	$ 1,000,000	$ 3,000,000
7. Rules 44 and 52 Deferral Offset	$ -	$ -	$ (1,000,000)	$ (2,000,000)	$ -	$ (1,000,000)	$ (2,000,000)
8. Rule 12 Deferral Offset	$ -	$ (2,000,000)	$ (1,000,000)	$ -	$ (500,000)	$ (500,000)	$ -
9. Merger Joint Proposal Deferral Account	$ -	$ (2,000,000)	$ (1,000,000)	$ 1,000,000	$ (500,000)	$ (500,000)	$ 1,000,000
10. Total Standby Service and Merger Deferral Accounts	$ -	$ 2,000,000	$ 3,000,000	$ 5,000,000	$ -	$ -	$ 1,500,000

1. Illustrative Actual Annual Standby Service Lost Revenues
2. Illustrative Actual Annual Rules 44 and 52 Lost Revenues
3. Max (- Line 1 - Line 2) or -2,000,000
4. Line 1 + Line 2 + Line 3
5. Line 1
6. Line 2
7. If Line 5 + Line 6 greater than zero than Max (-Line 6 or -2,000,000 or - Line 6 - Line 7) else zero
8. Min (Max (- 2,000,000 - Line 7 or Line 5) or Zero)
9. Line 6 + Line 7 + Line 8
10. Line 5 + Line 9

Exhibit__(JJB/SDL-10)

STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

Case 01-E-1847 - In the Matter of the Compliance Filing of Niagara Mohawk Power Corporation in Response to Opinion No. 01-4 on Stand-By Service Rates.

Case 01-M-0075 - Niagara Mohawk Power Corporation - Joint Petition For Approval of Merger and Stock Acquisition.

STAFF STATEMENT IN SUPPORT OF JOINT PROPOSAL

PRELIMINARY STATEMENT

In Opinion No. 01-4,[1] the Commission adopted guidelines for the design of stand-by service rates. A stand-by service customer obtains some of its electric usage from a source other than deliveries through the utility's transmission and distribution grid. These customers generally fall into two categories: 1) customers that install on-site generators (OSG) that produce energy primarily to serve a portion or all of the customer's load; and, 2) wholesale generators that produce and sell electricity into the wholesale market. Stand-by rates apply to the service both types of customers purchase from the utility in either supplementing their electricity supply or replacing the electricity they would otherwise supply themselves.

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[1] Case 99-E-1470, Proceeding on the Provision of Electric Stand-By Service, Opinion No. 01-4 (issued October 26, 2001).

On November 28, 2001, Niagara Mohawk Power Corporation (Niagara Mohawk) filed proposed tariff leaves establishing new electric stand-by service rates, in conformance with the Opinion No. 01-4 stand-by guidelines (SG), and Opinion No. 01-6, where a Rate Plan was adopted for the utility.[2] As required in the latter Order, Niagara Mohawk promptly conducted a technical conference on the filing. Negotiations thereafter commenced on January 22, 2002, and culminated in a Joint Proposal (JP) that was filed on March 12, 2002.

The Joint Proposal should be adopted because it satisfies the criteria the Commission has established for judging the reasonableness of utility rate settlements. In considering recent joint proposals setting forth agreement among parties, the Commission has generally evaluated each joint proposal on its own merits against a standard of reasonableness. It has also reviewed the adequacy of joint proposals in furthering the progress of implementing retail competition. These reviews have been conducted in conformance with the guidelines the Commission established in Opinion No. 92-2 for consideration of settlements.[3]

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[2] Case 01-M-0075, Niagara Mohawk Power Corporation et al. - Approval of Merger, Opinion No. 01-6 (issued December 3, 2001).

[3] Case 90-M-0255, Proceeding on Settlement Procedures and Guidelines, Opinion No. 92-2 (issued March 24, 1992).

Opinion No. 92-2 identifies a number of criteria for judging whether a joint proposal setting forth a settlement is in the public interest. In considering a joint proposal, the Commission reviews the extent to which it is supported by generally adverse parties and determines that the record for decision is adequate. In order to win approval, a joint proposal should be consistent with law and public policy, have a rational basis, balance the interests of customers and the utility, and compare favorably with the probable outcome of litigation. The Joint Proposal here satisfies these criteria.

There is broad support for the Joint Proposal. Multiple Intervenors (MI), a consumer group adverse to the interests of Niagara Mohawk, has joined in the Joint Proposal, with exceptions. Wholesale generators like NRG companies (NRG) and Orion Power New York G.P., Inc. (Orion) also support the Joint Proposal. The Independent Power Producers of New York (IPPNY) and National Fuel Gas Distribution Corporation (NFG), also parties adverse to the interests of Niagara Mohawk, lend their support, with exceptions. While the settlement is not unanimous, there is support for it among a broad range of parties representing customer interests.

The record is adequate to justify adoption of the Joint Proposal. Niagara Mohawk has submitted voluminous supporting workpapers justifying the proposed rates, and parties conducted detailed discovery into the basis for the proposed stand-by rates. This evidence is sufficient to justify approval of a tariff compliance filing such as Niagara Mohawk has submitted.

The remaining Commission criteria for judging the reasonableness of a joint proposal are directed towards ascertaining whether the proposed terms are in the public interest. For the reasons discussed below, the Joint Proposal meets that standard.

DISCUSSION

The stand-by rates proposed in the Joint Proposal satisfy the stand-by rate guidelines that were promulgated in Opinion No. 01-4, and conform to the Rate Plan for Niagara Mohawk promulgated in Opinion No. 01-6. As a result, the stand-by tariff and associated rate recovery and deferral mechanisms should be adopted.

I. Application of Stand-By Rates

A. Isolation of Load

Under the stand-by guidelines, stand-by rates should not be imposed on customer load that is isolated from the utility's T&D grid(SG §I.A.1.a). The Joint Proposal achieves that goal by defining electrical isolation. The definition permits loads to qualify as isolated even if separated by less than a distance of 100 feet, so long as the loads are not situated within a common enclosure. Allowing a load to be isolated, even though it is within close proximity to utility-served load, affords customers additional opportunities to serve an isolated load with their own generator without incurring the payment of stand-by rates for that load.

B. Wholesale Generators

Policies for furnishing stand-by service to wholesale generators are adumbrated in the stand-by guidelines (SG §I.A.1.b to §.3). Consistent with those guidelines, the Joint Proposal stand-by rates will adhere to wholesale generator usage of utility service for electric loads such as station use and start-up power, where the generator does not self-supply the service. As required by the guidelines, wholesale generators are allowed to net energy they self-supply against their station use.

As the guidelines require, wholesale generators that, when operating, supply all of their electric energy needs from behind the meter, will not be charged the as-used demand charge for stand-by service. Service remains "behind the meter" when the energy the generation facility produces for station use does not pass through the point of interconnection between the generator and the utility delivery system. Self-supply of station use during times when those operational circumstances exist, of course, does not free a wholesale generator from paying the stand-by rates applicable to times when it takes utility service. In other words, it must still pay the monthly customer charge, monthly contract demand charge and other relevant stand-by rate charges, even though the as-used demand charge component of stand-by rates will not be imposed on a generator while it is self-supplying.

The Joint Proposal also implements the guidelines' prescriptions for service to wholesale generators that take their station use through the same bus bar they use for delivering their generation production to the wholesale grid(SG §I.A.1.b). When the generator is operating, this type of service is treated the same as if the generator were supplying itself behind the meter, with the exception that the generator must pay any charges associated with the cost of the bus bar. Again, when operating, no as-used demand charge is applied to the generator, but it remains responsible for stand-by charges related to times when it does take utility service.

Wholesale generator station use includes the generator's energy consumption at its structures and associated support facilities located on the generating site. In some instances, some of these loads may be separately metered. Under those circumstances, the generator is not self-supplying the load from its own output. These loads are then served at the standard tariff rates applicable to the separately-metered usage.

C. Stand-By Rate Exemptions

Some customers are exempted from the S.C. 7 classification, and consequently are grandfathered to the otherwise applicable service classifications. Exemptions were created for small generators, sized at or less than 5 kVA; for customers that were previously grandfathered under Niagara Mohawk's Rule 12, except for wholesale generators served at the S.C. 3 and S.C. 3A transmission and subtransmission levels; renewable generators; and, New York Power Authority (NYPA) programs and flex rate contracts. Many of these exemptions expire on or are scheduled for reconsideration at times defined in the JP proposed tariffs, thereby limiting their impact on other ratepayers.

1. Small Customers

Affording exemptions to the small generators promotes opportunities to expand use of experimental technologies by freeing them from the full cost of stand-by delivery service. Allowing these generators to remain on the otherwise applicable tariff rate also permits developers of small generator technologies to market and test those technologies based on their cost expectations. At 5 kVA, the size limitation is large enough to encompass technologies targeted to residential customers. This approach should be sufficient to reasonably promote the development of these technologies.

Continuing grandfathering for existing customers other than the wholesale generators who were previously grandfathered under Rule 12, is similarly reasonable. Most of those customers made an investment in OSG generation based on existing costs and conditions at the time. If subjected to the new stand-by rates, those investment expectations could be jeopardized and the customers could face potentially significant bill impacts. Promoting smaller-sized distributed generation is among the Commission's goals, and these provisions further promote achievement of that goal.

2. Renewable Technologies

Renewable technologies are also specifically encouraged. Photovoltaic (PV), wind, and anaerobic digesters (fueled with manure) sized below certain limits are also exempted from stand-by service rates. The limits, at 50 kVA for PV and wind installations or 130 kVA for digesters, reasonably promote small facilities while protecting other customers from unreasonable cost shifting that could be associated with larger facilities of these types. To further protect other ratepayers, an exemption will terminate if the estimated amount of net lost revenues accumulated in a deferral subaccount for each technology exceeds $250,000.

The method Niagara Mohawk proposes for calculating these deferrals is reasonable. Moreover, the overall size of the deferral, at $750,000, exceeds the previous $500,000 deferral cap for renewables generally. Affording each technology a separate deferral subaccount also ensures that each may develop at its own pace unhampered by the success of another technology that might otherwise deplete the entire account. The stand-by rate proposal therefore properly balances the interests of renewable facility development with the interests of other ratepayers and the utility.

3. NYPA Programs

Stand-by service rates will not adhere to customer load served under NYPA programs or under an individually-negotiated flex rate contract pursuant to S.C. 11 or S.C. 12. This exemption is appropriate, to prevent interference with the special features of those programs, which are designed to encourage economic development. The economic development goals should not be frustrated by the unintended and unwarranted extension of stand-by rate principles to electric services provided under those special programs.

II. Stand-By Rate Design

A. Stand-By Rate Cost Causation

Under SG §II.A, fully separate service classifications for stand-by customers are not required. Costs allocated to the existing standard service classifications will serve as the basis for the design of class-specific, revenue-neutral stand-by service delivery charges. To the extent stand-by service poses cost causation characteristics that differentiate the service from that provided to the balance of customers in the otherwise applicable service classifications, rates reflective of those differences can be developed within each classification.

Under the Joint Proposal, Niagara Mohawk establishes a new S.C. 7 classification to serve the unique needs of OSG and wholesale generator customers. In conformance with the guidelines, the S.C. 7 rates were based on the same revenue targets that were used to establish the firm service rates for the relevant standard service classification,[4] by converting the existing billing determinants to accommodate the new stand-by rate structure. As a result, the stand-by rates are class revenue-neutral, as the guidelines require(SG §II.A).

It should be emphasized that the Niagara Mohawk stand-by rates set forth in the Joint Proposal are for delivery service exclusive of electric energy supply costs(SG §II.C.2). Stand-by customers retain their right to acquire energy supply from the utility or an alternative provider pursuant to applicable utility tariffs and alternative supplier rates and

[4] The firm service rates are those established for Niagara Mohawk in Case 00-M-0075 upon its merger.

terms. Moreover, generators retain the right to self-supply energy and net their station use against their energy output.

B. Delivery Cost Recovery

The guidelines call for recovery of delivery costs through a monthly access charge that recovers customer-related costs, to the extent not otherwise recovered through interconnection charges(SG §II.D). Distribution delivery costs are recovered through a combination of class specific monthly customer, contract demand, and daily as-used demand charges, recovering fixed and variable costs appropriately. The Joint Proposal for Niagara Mohawk stand-by rates recovers embedded customer costs and fixed delivery costs through a customer charge and a contract demand charge. This approach conforms to the guidelines(SG §II.E).

The Joint Proposal also establishes reasonably cost-based contract and as-used demand charges. The design of these two charges is the result of a compromise of the parties' various positions, and represents a substantial change from the stand-by rates Niagara Mohawk initially proposed. The principles established in the stand-by guidelines for the design of these charges, however, were recognized in developing the compromise result.

Fixed costs recovered through the contract demand charges are generally local in nature, in that the costs of the distribution facilities are attributable to individual customer loads. In a cost study, such local costs are generally those that are allocated to a customer on an aggregate non-coincident basis. The contract demand charge that recovers this cost is then based on the sum of each customer's maximum anticipated annual metered demand.[5] This approach is consistent with the guidelines, properly recovering the local fixed costs through the contract demand charges (SG §II.E.3).

As-used demand charges are used to recover the costs of shared facilities, that are more related to customers' maximum coincident peak use of the delivery system. These costs tend to be more widely dispersed among customers, because they are less driven by individual customer peaks. In a cost study, the costs of these shared facilities are generally allocated on a system coincident or non-coincident peak basis. The Joint Proposal reasonably reflects shared costs and the allocation of those costs to the as-used demand component, in conformance with the guidelines (SG §II.E.4).

The as-used demand charges are designed in recognition of the more intermittent demand individual stand-by delivery

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[5] In administering the rate, where an individual customer's usage characteristics have demonstratively changed after the contract demand charge has been imposed, the customer will be permitted to request a reduction in the monthly contract demand level, but conversely will be assessed a penalty if actual demand exceeds the adjusted contract demand.

service customers impose on the utility system. The greater the revenue recovered through volumetric charges, the greater the exposure of the utility and its remaining ratepayers to lost revenues from customers installing OSG. The charges are applied on a daily, rather than a monthly basis, to a customer's daily maximum metered demand during the utility's on-peak period. Following this approach, intermittent users, who place less frequent demands on the system during hours of peak use, thereby imposing lower costs, are in fact charged less than users that impose more frequent demands on peak, and thus are responsible for a larger portion of the shared system costs.

The proportion of fixed and variable cost recovery through the proposed contract and as-used demand charges is reasonable and cost-based. If the resulting rate design were too heavily weighted towards fixed cost recovery, customers could overpay for delivery service, which would inappropriately discourage the installation of potentially economically-efficient generation. On the other hand, if the rate design were heavily weighted towards volumetric recovery, as is the case with merger standard delivery rates adopted in Case 00-E-0075, customers installing generation could avoid delivery costs that they actually impose on the delivery system. This would unfairly shift those costs to other customers.[6]

The proposed stand-by rates represent a compromise among the settling parties that more fairly recognizes cost responsibility among individual delivery service customers. As such, the proposed rates should afford more opportunity for customers to pursue economic on-site generation installations than they could under Niagara Mohawk's previous Rule 12, without inappropriately transferring revenue responsibilities to other ratepayers.

C. Transmission Cost Recovery

One component of the as-used charges is transmission cost, since those facilities are obviously shared. The cost is based on the Federal Energy Regulatory Commission's (FERC) Open Access Transmission Tariff (OATT), as provided for in the guidelines at SG §II.F. The FERC charges are inherently included in the calculation of the as-used demand charge because the associated transmission revenues are included in the class revenue target.

[6] Attached as Appendix A is a comparison of revenue requirement recovered through volumetric charges under the merger and proposed stand-by rates.

D. Stranded Costs

Under SG §I.A.4, charges or credits from the otherwise applicable service classification are imposed on stand-by customers. The Joint Proposal draft tariffs implement that approach. Moreover, consistent with SG §I.B, Niagara Mohawk's stand-by customers will contribute to stranded cost recovery.

Stranded costs are appropriately recovered through a uniform percentage mark-up of the applicable rate components for stand-by service, so that stand-by customers contribute to stranded cost recovery in the same proportion of their deliery service revenues as other customers in the otherwise applicable service classification. This proportionate recovery mechanism insures that every customer bears its share of the stranded cost burden relative to the delivery services being provided and stand-by customers are prevented from unreasonably shifting their share of the burden to other customers.

E. Interconnection Costs

The Joint Proposal rates also properly reflect SG §II.B, on interconnection costs. Generators that require interconnection facilities and equipment beyond those delivery facilities normally required to supply firm retail service to customers of comparable size, will pay for those additional facilities through a separate interconnection agreement or charge. Concomitantly, those costs are not reflected in the stand-by rates charged to those customers.

Moreover, Niagara Mohawk transmission and sub-transmission customers in the S.C. 3 and S.C. 3-A classes that have funded the cost of interconnection facilities and metering equipment, but pay Niagara Mohawk for ongoing operation and maintenance of those facilities, are charged a lower customer charge than is applicable to full-service customers. The reduction in this charge recognizes the advance payments and ongoing maintenance payments from these customers.

F. Rate Design For Small Customers

1. Demand Metering Requirements for Small Customers

The stand-by guidelines, at SG §II.G, address the specifications for separating small from large customers. The guidelines require that all stand-by customers with contract demands in excess of 50 kW be interval-metered. A stand-by customer with a contract demand below the 50 kW level that is demand-metered by the utility, has the option of taking service at either the otherwise-applicable demand rate or the new interval-metered stand-by rate applicable to the above 50 kW customers. The Joint Proposal stand-by tariffs implement these requirements.

2. Non-Demand Small Customer Charges

The guidelines also prescribe requirements for smaller non-demand metered stand-by customers (SG §II.G.3). The average customer cost for the service classification, metering, billing and fixed distribution costs would be recovered through monthly customer and contract customer charges. The volumetric rate for as-used delivery service is then set at a non-time differentiated level that has a revenue neutral impact on the entire service classification.

As a result, the stand-by energy rate for these non-demand customers is set at the amount needed to recover the full revenue requirement of the service classification under the Joint Proposal. The Joint Proposal rates for non-demand metered customers reflect customer and customer demand charges designed to include fixed or local costs, in accordance with the guidelines. Remaining costs are recovered through a volumetric charge designed on a revenue neutral, non-time differentiated basis to recover the remaining class revenue requirements.

For example, Niagara Mohawk's stand-by rate for residential customers provides for fixed monthly charges of approximately $34. This charge is roughly equivalent to the sum of the total customer and contract customer costs for the class, at about $29, marked up by the relevant competitive transition charge of about $5. As a result, these charges are appropriate.

G. Split Billing

The stand-by rate structure also includes a split billing provision. Customers installing OSG equipment sized below 15% of their maximum potential demand will be billed at the stand-by delivery rate for the load served by OSG, but at the standard rate for the remainder of their load. This prevents the potential for gaming by customers installing OSG equipment sized at a small portion of its maximum load for the purpose of accessing the potentially more favorable stand-by rate for all its usage. This limitation on stand-by service also restricts the accumulation of additional lost revenue that would accrue if all of such service were billed at the stand-by rate. The selection of the 15% limitation is appropriate.[7] Accordingly, this billing provision protects remaining ratepayers, and is therefore reasonable.

III. Deferrals and Lost Revenue Recovery

Under §1.2.4.17 of the Rate Plan adopted for Niagara Mohawk in Opinion No. 01-6, the utility was allowed to defer all verifiable losses associated with the implementation of the stand-by guidelines. Excluded from the revenue lost deferral is

[7] The 15% limitation was agreed upon by the parties as a reasonable level that prevents excessive potential revenue losses from the unintended application of this new stand-by rate, based on an economic analysis performed by Niagara Mohawk and reviewed by the parties.

the first $2.0 million of verifiable revenue losses for each calendar year from September 1, 2003 through the expiration of the Rate Plan.

The Joint Proposal here effectuates the deferral provision of the Rate Plan. JP §2.1.1 sets forth the lost revenue calculation, established through a comparison of the delivery service billings under the stand-by rate to the delivery service billings that would have been made by Niagara Mohawk under the prior Rule 12, operating in conjunction with standard service classification rates. This approach accords fully with Niagara Mohawk's Rate Plan.

Under JP §2.1.2, lost revenues will accrue in a deferral account. Account balances will not accrue interest or carrying charges, but shall be added to or subtracted from Niagara Mohawk's rate base for the purpose of its earnings reports. Lost revenues are thereafter recovered as explained at JP §2.1.3.

Again, this provision is consistent with the Niagara Mohawk Rate Plan. The lost revenues associated with stand-by service are blended into other deferrals for recovery if appropriate under the Rate Plan, in association with the resetting of the CTC. This approach to lost stand-by revenues fully comports with the Commission's decision in Opinion No. 01-6, and should be adopted here.

CONCLUSION

For the foregoing reasons, Staff requests that the Administrative Law Judge and the Commission approve the Joint Proposal, because it provides for stand-by rates that comply with the stand-by guidelines the Commission established in Opinion No. 01-4, and because those rates are non-discriminatory, further the Commission's policy objectives, balance the interests of all the parties, and constitute a fair resolution of the issues in these proceedings.

Respectfully submitted,

Leonard Van Ryn
Staff Counsel

Dated: March 26, 2002
Albany, New York

Exhibit__(JJB/SDL-11)

STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

In the Matter of the Compliance Filing of Niagara Mohawk Power Corporation in Response to Opinion No. 01-4 on Standby Service Rates.

Case No. 01-E-1847

NIAGARA MOHAWK POWER CORPORATION

STATEMENT IN SUPPORT OF JOINT PROPOSAL

By: **Lisa Gayle Bradley, Esq.**
Niagara Mohawk Power Corporation
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Dated: **March 25, 2002**

STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

In the Matter of the Compliance Filing of Niagara Mohawk Power Corporation in Response to Opinion No. 01-4 on Standby Service Rates.

Case No. 01-E-1847

NIAGARA MOHAWK POWER CORPORATION

STATEMENT IN SUPPORT OF JOINT PROPOSAL

On March 12, 2002, Niagara Mohawk Power Corporation ("Niagara Mohawk" or "Company") filed with the State of New York Public Service Commission ("Commission") a Joint Proposal in this proceeding reflecting a settlement reached among the Company, the Department of Public Service, Independent Power Producers of New York, Inc. ("IPPNY"), Multiple Intervenors ("MI"), National Fuel Gas Distribution Corporation ("NFG"), NRG Companies, and Orion Power New York GP, Inc. (collectively "Settling Parties") in connection with standby electric service. As noted by some signatory parties to the Joint Proposal, the Joint Proposal does not reflect consensus on all issues.

Niagara Mohawk is now submitting this Statement in Support of the Joint Proposal. The Statement will summarize the Joint Proposal, and, in so doing, will note which parties are supporting the various aspects of the Joint Proposal. The Statement will also explain the respects in which the Joint Proposal differs from the Company's original filing of November 28, 2001 ("Original Filing"). Finally, the Statement will explain the respects in which the Joint Proposal satisfies applicable Commission settlement guidelines and thus merits Commission approval.

1. STANDBY SERVICE RATES AND CHARGES

All parties have agreed to the standby delivery rates and charges set forth in Attachment 1 of the Joint Proposal. However, as discussed hereafter, IPPNY, MI and NFG have excepted to the Company's method of applying the Competitive Transition Charges ("CTCs") to the various transmission and distribution ("T&D") billing charges.

As in the Original Filing, the new standby delivery rates will appear in a separate rate schedule, Service Classification No. 7 ("SC-7") to Niagara Mohawk's Tariff, P.S.C. No. 207, Electricity. Subject to the SC-7 applicability requirements, the individual rates within SC-7 will apply to standby service customers whose parent classifications are SC-1 Residential, SC-1B Residential, SC-1C Residential, SC-2 Small General Service Non-Demand Metered, SC-2 Small General Service Demand Metered, SC-3 Large General Service, SC-3A Large General Service, SC-4 Supplementary Large General Service, and SC-5 Combined 25 Hz and 60 Hz Large General Service. The billing charges are the same as those in the Original Filing. Specifically, the basic delivery billing charges common to all parent demand-metered classifications consist of a Customer Charge, a Standby Contract Demand Charge, both representing fixed charges attributable to "local" facilities; and an As-Used On-Peak Daily Demand Charge, representing variable charges attributable to "shared" facilities. For those service classifications that are not demand based, i.e., SC-1 and SC-2 Non-Demand, a Standby Contract Customer Charge replaces the Standby Contract Demand Charge for "local" facilities charges and an As-Used Daily Energy Charge replaces the As-Used On-Peak Daily Demand Charge for "shared" facilities charges. In addition, those SC-2D customers less than 50 kW who do not elect interval metering will pay the currently effective standard SC-2D rate for standby service.

The following table reflects the differences between the Original Filing and the Joint Proposal with respect to the percentage allocations of local and shared facilities:

Percent Shared Facilities Revenue Requirements

Service Classification	Original Filing	Joint Proposal
SC-1	5.9%	16.0%
SC-2ND	5.6%	16.0%
SC-2D	9.0%	33.0%
SC-3		
Secondary	13.3%	35.0%
Primary	16.7%	35.0%
Subtransmission	35.5%	33.7%
Transmission	27.4%	27.4%
SC-3A		
Secondary	19.9%	38.5%
Primary	16.5%	49.8%
Subtransmission	42.8%	65.9%
Transmission	48.0%	64.1%
TOTAL	9.5%	24.2%

The overall rate design is set forth in Supporting Workpaper 3.

For customers with a Standby Contract Demand, the Joint Proposal departs from the Original Filing by permitting SC-7 customers to nominate a lower Standby Contract Demand than the Company would otherwise determine upon notice to the Company. In order to address shared concerns for the possible understatement of Contract Demand, the Settling Parties agreed to penalties that would apply in the event an SC-7 customer obtained a reduced Standby Contract Demand, only thereafter to have recorded maximum demands in excess of the customer's nominated demand. A sliding scale approach was adopted to tie penalty amounts to the percentage by which the recorded demands exceeded the nominated demands (JP Attachment 1, Leaf 106-C).

As in the Original Filing, the new SC-7 rates will also include a Reactive Power Demand Charge applicable to those customers whose parent classification includes such a charge. The Reactive Power Demand Charges will be the same as those in the parent service classifications. As part of the settlement in this proceeding, the Settling Parties have agreed that, similar to the parent classification, Reactive Power Demand Charges (other than start-up reactive demand charges) would be waived, within Company-specified parameters, for wholesale generators in excess of 25 MVA who install automatic voltage control ("AVC") at their facilities (JP Attachment 1, Leaf 106-K).

Also as in the Original Filing, customers taking service under SC-7 will be subject to the same Customer Charges applicable to those customers in the parent classifications. The Settling Parties have agreed, however, that a reduced Customer Charge will apply to wholesale generators receiving standby service who (a) have a parent service classification of SC-3 or SC-3A and are served at the subtransmission or transmission voltage level; (b) have paid for all of their interconnection facilities (as defined in a separate interconnection agreement) and metering equipment; and (c) have agreed to pay the Company ongoing operation and maintenance costs for that equipment (JP Attachment 1, Leaf 106-I).

Finally, the new SC-7 rates will include the following additional charges as they appeared in the Original Filing: an Incremental Customer Charge assessed against applicable customers covering the incremental cost of metering and meter communications equipment necessary to administer standby service for those customers; an Electricity Supply Service Charge where

Niagara Mohawk is providing the electricity commodity to the customer; and those surcharges and adjustments as provided under the otherwise applicable parent service classifications.

A comparison of the SC-7 delivery rates to the merger rates approved by the Commission in Case 00-M-0075 appears in Supporting Workpaper 1. A summary, by parent classification, of the Contract Demand multiplier, As Used On-Peak Daily Demand/Energy, and Transmission Coincident Demand Billing determinants appears in Supporting Workpaper 4.

In the Company's opinion, the proposed SC-7 rates and charges are just and reasonable, and should be adopted by the Commission without modification. The Joint Proposal T&D Contract Demand/Customer Charges are lower than those originally proposed by the Company and the T&D As-Used Daily On-Peak Demand/Energy Charges are higher than those originally proposed by the Company, and, on balance with the other provisions of the Joint Proposal, have the full support of all Settling Parties.

2. COMPETITIVE TRANSITION CHARGES

As previously noted, all Settling Parties have agreed to the standby delivery rates and charges set forth in Attachment 1 of the Joint Proposal, inclusive of the Competitive Transition Charges ("CTCs"), except for IPPNY, MI (as to the SC-3A CTC charges only), and NFG.

The allocation of CTC under the Joint Proposal is the same as that under the Original Filing. Specifically, the allocation of each parent class's unbundled CTC is made on a uniform percentage mark-up to the applicable T&D standby service rates. A percentage ratio of CTC revenue collection versus T&D revenues is shown in Supporting Workpaper 2. This uniform percentage ratio was applied to each of the T&D (customer, contract demand/customer, as-used on-peak daily demand/energy) charges to derive each CTC charge. Application of a uniform percentage mark-up by load zone for each service class and voltage level is necessary for consistency and revenue neutrality between the parent class rates and the standby service rates.

Niagara Mohawk believes that this allocation of CTC is consistent with the Commission's Opinion No. 01-4, issued and effective October 26, 2001 in Case 99-E-1470 ("Standby Order"), which requires that:

> The contribution to stranded costs by Standby Delivery Service customers should be established through a uniform percentage of mark-up of the applicable rate components established for Standby Service such that standby customers contribute to stranded cost recovery in the same proportion of their delivery rates as customers in the otherwise applicable service classification.

Standby Order, App. A Guidelines, Section I (B), p 2. As discussed above, the Company's proposed SC-7 rates fully satisfy these requirements of uniformity and proportionality.

3. APPLICABILITY

All Settling Parties, with the partial exception of MI as discussed hereafter, have agreed to applicability criteria that, in several respects, differ markedly from those set forth in the Original Filing.

With respect to "Wholesale Generators", which is a newly defined term in the Joint Proposal (JP Attachment 1, Leaf 23-A), standby rates will apply to station service taken through the same bus bar used by the these generators to supply the wholesale grid. All Settling Parties have agreed to a definition of "Same Bus Bar" that is more expansive than that set forth in the Original Filing (JP Attachment 1, Leaf 102). The Company believes that this definition should be approved as consistent with the Standby Order.

With respect to SC-7 Exemptions, all Settling Parties have agreed to the original exemptions for electrically-isolated loads, "behind the meter" service, separately metered accounts not served by OSG, small residential photovoltaic systems, and emergency power systems (JP Attachment 1, Leaves 102(A), 102(b) - 102(C)). In accordance with the Standby Order, the Settling Parties have also agreed that customers who would otherwise receive service under SC-2 Demand and who have Standby Contract Demands less than 50 kW, will have the option to take service either at the otherwise applicable demand rate or, upon installation of interval metering, at the SC-7 demand rate (JP Attachment 1, Leaves 102(C), 106-F). This provision is also consistent with the Commission's directives in the Standby Order (p. 9). The Settling Parties have further agreed to expand the original exemption for small OSG units. The Original Filing exempted OSG units smaller than 5 kVA from the SC-7 rates, instead placing these units on applicable standard rates. The Joint Proposal extends this exemption to OSG units 5 kVA or smaller, provided they are installed and operating prior to December 31, 2005 (JP Attachment 1, Leaf 102-A(1)).

In addition to these original exemptions, all Settling Parties have agreed to new exemptions pertaining to NYPA programs, individually negotiated SC-11 and SC-12 contracts, and renewable generators (JP Attachment 1, Leaves 102-A(1) - 102-B). All Settling Parties except MI also have agreed to create a new exemption for certain grandfathered Rule 12 customers (JP Attachment 1, Leaf 102-A(1)). Under this exemption, SC-7 rates will not apply to customers served under the standard service classifications as of January 1, 2002 who have executed forms Gf and who were grandfathered from Rule 12.1 of the Tariff as of January 1, 2002.

As set forth on MI's signature page to the Joint Proposal, MI has dissented from this grandfathering provision: "Multiple Intervenors opposes the proposal that all customers with existing on-site generation ('OSG') have executed a Form Gf and are grandfathered from Rule 12 also must be grandfathered from the applicability of the new standby rates." MI's position seems to indicate a preference for customer self-selection of SC-7 rates or standard rates. Niagara Mohawk opposes self-selection because it would create the opportunity for windfall gains for self-selecting customers and windfall losses for remaining customers. For this reasons, and in view of the other benefits contained in the proposed SC-7 rates and terms for businesses that are members of MI and other similarly situated customers, Niagara Mohawk believes that the exemption for certain grandfathered Rule 12 customers should remain as filed in the Joint Proposal and agreed to by all signatories other than MI.

4. INTERCONNECTION REQUIREMENTS

All Settling Parties have agreed to the same types of interconnection requirements that appear in the Original Filing (JP Attachment 1, Leaf 106-E). These requirements, which pertain to parallel operations, interconnection agreements, and interconnection costs, are reasonably intended to further the Company's delivery of safe, reliable, and economic service to all customers; and are consistent with federal and state policies regarding interconnections. As such, the Company urges their approval by the Commission.

5. METERING AND COMMUNICATIONS REQUIREMENTS.

All Settling Parties have agreed to metering and communications requirements addressing interval metering and telecommunications (JP Attachment 1, Leaf 106-F). These requirements are reasonable and, in Niagara Mohawk's opinion, should be approved by the Commission.

6. SPECIAL PROVISIONS

The proposed SC-7 terms and conditions include the same types of Special Provisions as set forth in the Original Filing, viz., provisions pertaining to Standby Demands greater than 1000 kW; SC-4 customers; compliance with reliability criteria; electrically isolated loads; and penalties for reconnecting isolated loads without notice (JP Attachment 1, Leaves 106-G - 106-H). All Settling Parties have agreed to these provisions.

In order to address shared concerns about rate arbitrage, all Settling Parties have also agreed to add a provision applicable to customers having on-site generators ("OSGs") less than 15% of maximum potential demand. For customers whose OSG is less than 15% of the customer's maximum potential demand over the previous 12 months, the customer will be subject to SC-7 delivery charges for the portion of the customer's load served by the OSG and the delivery charges of the otherwise applicable service classification for the remainder (JP Attachment 1, Leaves 106-J - 106-K).

The sole purpose of this provision was to reduce the opportunity for rate arbitrage inherent when a customer is eligible to take service under more than one rate and there are minimal or no effective restrictions in the applicability provisions of the rates to preclude inappropriate rate switching. The Commission concluded in its Standby Order (pp. 21-22) that its adopted standby rate guidelines will result in cost-based delivery rates that should apply to a customer's entire delivery service, regardless of whether all or part of the customer's load is served by OSG. Nevertheless, the Settling Parties did recognize that rate arbitrage opportunities did exist between the standard service rates and the standby rates designed in accordance with the guidelines, and have taken appropriate steps to mitigate the problem by adopting the foregoing provision.

As reflected in its signature page of the Joint Proposal, the MI "opposes the proposal that all non-grandfathered customers with partial OSG that is 15% or greater (but less than 100%) of their peak demands must be subject to the new standby rates for their entire load, including the portion of their load that is not served by OSG." MI apparently is taking the position that such customers should have the right to select standard rates for the portion of their loads not served by OSGs. Niagara Mohawk opposes the inclusion of a special provision of that nature for the same reasons the Company's opposes a self-selection of the applicable service classification rate as discussed in Section 3 above; and because it would allow customers to avoid paying for fixed costs, including transmission, distribution, and CTC, thereby defeating the purpose of developing cost-based standby rates in the first place. Moreover, because of other provisions adopted by the Company in the Joint Proposal that benefit businesses such as those that are members of MI, the inclusion of additional benefits would eliminate the equity and careful balancing that was achieved in reaching the Joint Proposal. Finally, MI's position again seems to indicate a preference for customer self-selection of SC-7 rates or standard rates; this time for portions of a customer's load. Again, Niagara Mohawk opposes self-selection because it would create the opportunity for windfall gains for self-selecting customers and windfall losses for remaining customers. For these reasons, Niagara Mohawk believes that the provision applicable to customers having OSGs less than 15% of their maximum potential demand should remain as filed in the Joint Proposal and agreed to by all signatories other than MI.

7. <u>LOST REVENUE RECOVERY</u>

Critical to the Company's assent to the proposed SC-7 rates, and the associated terms and conditions, are the lost revenue recovery provisions set forth in the Joint Proposal and Attachment 2 thereof.

By way of background, Section 1.2.4.17 of the Merger Rate Plan approved in Case 01-M-0075 provides for Niagara Mohawk's recovery of verifiable lost revenues associated with modifications to the Company's existing Rule 12 Tariff provisions. In furtherance of this Merger Rate Plan provision, and as part of this Joint Proposal, Niagara Mohawk has agreed to calculate each month the verifiable lost or gained revenue per customer associated with the implementation of the SC-7 tariff, with reference to delivery service billings that would have been made under the superseded Tariff provisions. A deferral account for Standby Service Lost Revenue ("Standby Service Lost Revenue Deferral Account") will be created as to which lost or gained revenue will be added or subtracted on a monthly basis. No interest or carrying charge will accrue on the balance in the Standby Service Lost Revenue Deferral Account; and the balance will be added to or subtracted from Niagara Mohawk's rate base.

Coincident with its CTC reset filings, as described in Section 1.2.3.3 and Attachment 7 of the Company's Merger Rate Plan, Niagara Mohawk will make a compliance filing to calculate a Standby Service Lost Revenue Rate Adjustment, subject to implementation if and when the sum of the Company's June 30 cumulative deferral balance under the Merger Rate Plan and the June 30 cumulative standby service lost revenue deferral balance is positive. The methodology used to allocate the Standby Service Lost Revenue Rate Adjustment among Niagara Mohawk's individual rate classes will be subject to review and comment by the parties at the time that the Standby Service Lost Revenue Adjustment is filed. Any Standby Service Lost Revenue Rate Adjustment will not be shown separately on Niagara Mohawk's bills, and, instead, will be added to or subtracted from the rate adjustments associated with the Company's CTC Reset.

Niagara Mohawk believes that the proposed lost revenue recovery mechanism is sound and far more preferable to inclusion of these lost revenues in the general deferral account under the Merger Rate Plan. Moreover, the Joint Proposal reflects many concessions made by the Company, as well as other parties, during the settlement process. Commission approval of the proposed recovery mechanism was, and remains, an essential consideration in the Company's decision to agree to the proposed SC-7 rates and the associated terms and conditions.

8. APPLICATION OF COMMISSION SETTLEMENT GUIDELINES

Under the Commission's long-standing settlement guidelines, a number of factors must be considered as part of the Commission decision whether to approve a filed settlement. The relevant questions, as adopted in Case 90-M-0255, are whether the proposed settlement is consistent with law and public policy, and compares favorably with the probable outcome of litigation; whether the proposed settlement balances the interests of customers and the utility; whether a rational basis and adequate record exist to support a favorable Commission decision; and whether the proposed settlement is supported by generally adverse parties.

Niagara Mohawk believes that all of these questions can and should be answered in the affirmative.

First, the Joint Proposal is fully consistent with the Commission's policies. In accordance with the Standby Order, the proposed SC-7 rates generally avoid reliance on measurements of energy consumed (kWh) for charges for delivery service, resting instead on cost-based principles and the Commission's standby service guidelines. The proposed rates are revenue neutral, class specific, and reflective of the existing allocations of costs to the various service classifications. The proposed class-specific SC-7 Customer, Contract Demand/Customer, and As-used Daily On-peak Demand Charges recover an appropriate allocation of "local" and "shared" facilities costs incurred by the Company in providing standby service, given the requirements of the Standby Order and the terms of the Joint Proposal overall. Provisions have been made to assure that customers in non-demand classes, and customers in demand classes without interval metering, will receive appropriate standby service rates. The proposed SC-7 rates provide neither a barrier nor an unwarranted incentive to customers contemplating the installation of on-site generation, and, in this respect, further the Commission's policy of not impeding the development of alternative sources of energy. Finally, no existing Federal or State laws, regulations, or policies would appear to prohibit or preclude the Commission's approval of the Joint Proposal.

Second, the Joint Proposal compares quite favorably to any probable litigated outcome. As was the case with the Guidelines adopted by the Commission in its Standby Order, the Joint Proposal strikes a balance among opposing points of view. At the same time, the settlement discussions in this proceeding have produced an outcome that is more favorable than would have resulted from litigation, as evidenced by the assent of important stakeholders to the Joint Proposal. Due to numerous concessions made by the Company, the result is appreciably lower Contract Demand Charges and higher As-Used Daily On-Peak Demand Charges than were initially proposed by the Company; and associated terms and conditions are more generous to customers than originally offered.

Third, the Joint Proposal balances the interests of customers and Niagara Mohawk and, further, is supported by a broad range of stakeholders of adverse interests. The list of signatories demonstrates the balance of interests represented by the compromise reached in the Joint Proposal. The breadth of interests represented by the proponents assures that the balance is fair, reasonable and appropriate. The Joint Proposal will further the interests of all customers classes.

Finally, a record exists in this case to support approval of the Joint Proposal by the Commission on a rational and reasonable basis. The confidential settlement discussions leading to the Joint Proposal were conducted on a principled basis, on notice to all interested parties, and consistent with the Commission's Rules and Regulations. Numerous information requests were initiated by parties and responded to by the Company. The rational basis for the Joint Proposal is set forth clearly in the document itself, its attachments and associated Supporting Workpapers, and in this Statement in Support.

CONCLUSION

For the foregoing reasons, Niagara Mohawk respectfully requests that the Joint Proposal Attachment 1 be adopted as written; and that the proposed lost revenue recovery mechanism be adopted as proposed.

Respectfully submitted,

NIAGARA MOHAWK POWER CORPORATION

/s/

By: ______________________________
Lisa Gayle Bradley, Esq.

300 Erie Blvd. West
Syracuse, New York 13202

Dated: March 25, 2002

To: Active Parties in Case No. 01-E-1847

STATE OF NEW YORK)
) ss.:
COUNTY OF ONONDAGA)

SCOTT D. LEUTHAUSER, being duly sworn, deposes and says: I am the Director of Energy Transactions of NIAGARA MOHAWK POWER CORPORATION; I have read the foregoing Statement In Support of Joint Proposal and know the contents thereof; the same is true to the best of my knowledge.

/s/

Scott D. Leuthauser

Sworn to before me this
____ day of March, 2002

/s/

STATE OF NEW YORK)
) ss.:
COUNTY OF ONONDAGA)

THERESA A. FLAIM, being duly sworn, deposes and says: I am the Vice President - Strategic Planning of NIAGARA MOHAWK POWER CORPORATION; I have read the foregoing Statement In Support of Joint Proposal and know the contents thereof; the same is true to the best of my knowledge.

/s/

Theresa A. Flaim

Sworn to before me this
____ day of March, 2002

/s/

STATE OF NEW YORK)
) ss.:
COUNTY OF ONONDAGA)

CATHERINE T. McDONOUGH, being duly sworn, deposes and says: I am the Senior Strategic Planner of NIAGARA MOHAWK POWER CORPORATION; I have read the foregoing Statement In Support of Joint Proposal and know the contents thereof; the same is true to the best of my knowledge.

/s/

Catherine T. McDonough

Sworn to before me this
____ day of March, 2002

/s/

STATE OF NEW YORK)
) ss.:
COUNTY OF ONONDAGA)

HERBERT SCHRAYSHUEN, being duly sworn, deposes and says: I am the Vice President - Transmission Services of NIAGARA MOHAWK POWER CORPORATION; I have read the foregoing Statement In Support of Joint Proposal and know the contents thereof; the same is true to the best of my knowledge.

/s/

Herbert Schrayshuen

Sworn to before me this
____ day of March, 2002

/s/

COMMONWEALTH OF MASSACHUSETTS)
) ss.:
COUNTY OF WORCESTER)

JAMES J. BONNER, JR., being duly sworn, deposes and says: I am a Principal Analyst, Distribution Financial Analysis, of NATIONAL GRID USA SERVICE COMPANY, INC.; I have read the foregoing Statement In Support of Joint Proposal and know the contents thereof; the same is true to the best of my knowledge.

/s/
____
James J. Bonner, Jr.

Sworn to before me this
____ day of March, 2002

/s/
____

COMMONWEALTH OF MASSACHUSETTS)
) ss.:
COUNTY OF WORCESTER)

JAMES M. MOLLOY, being duly sworn, deposes and says: I am a Principal Analyst, Regulatory Research, of NATIONAL GRID USA SERVICE COMPANY, INC.; I have read the foregoing Statement In Support of Joint Proposal and know the contents thereof; the same is true to the best of my knowledge.

/s/

James M. Molloy

Sworn to before me this
____ day of March, 2002

/s/

Exhibits of William R. Richer, Steven W. Tasker, and James M. Molloy

Exhibit___(P&O-5)

Journal Entry

Pension

New Window | Help | Customize Page |

Header | Lines | Totals | Errors | Approval

Unit: 00036 **Journal ID:** 6028 **Date:** 02/25/2006 ***Process:** Edit Journal

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☐	5	00036	698007	253024	217,004,187.00	253024	
☐	6	00036	698007	253027	-217,004,187.00	253027	

p. 2

Lines to add: 1

Totals Customize | Find | View All | First

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00036	6	218,332,346.00	218,332,346.00	

Save | Return to Search | Next in List | Previous in List | Notify | Refresh

Header | Lines | Totals | Errors | Approval

P. 1

Accrued Pension expense

True up FYE 3/31/05 NE Pension balances to Hewitt's 3/31/05 Disclosure Memo liability

Summary - Dr / (CR)		Per Hewitt	Per GL	variance
NE Pension - Qualified		334,620,592	334,733,445	(112,853)
NE Pension - Nonqualified		(83,808,103)	(87,544,906)	3,736,803
NY Pension - Qualified	Σ 1	(196,932,556) 1	(197,216,200)	283,644
NY Pension - Nonqualified		3 (7,461,932)	4 (8,506,447)	1,044,515
Total		46,418,001	41,465,893	4,952,108
		0	0	(0)

DR AG1060, DR 186000
DR 253031, CR AG1060
DR 253027, CR AG1060
DR 253031, ~~CR AG1060~~

Pensions

426200

× 83% = $235,425

	Total	Co 01	Nant Elec	Mass Elec	NEP	GS Elec	Narr Elec	Svc Co	NM	
Qualified Pension Plan	151,842,433							342,894,264	1 (191,051,831)	p. 7
Nonqualified Pension Plan	(91,270,035)							(83,808,103)	3 (7,461,932)	
NM - PSC Staff Adjts - FY03 - Interest Charged	(14,154,397)								1 (14,154,397)	p. 11
NM - Qualified - Svc Co piece - FY03/04								(3,833,786)	3,833,786	p. 12
NM - Qualified - Svc Co piece - FY04/05								(4,439,886)	4,439,886	p. 8
Pension Plan balance per Hewitt	46,418,001	0	0	0	0	0	0	250,812,469	(204,394,488)	
186107 - Per GL - Intangible Asset	54,888,244		51,346	5,011,933	1,361,858	186,837	2,394,980	5,541,871	~~40,339,419~~	Net = 0
253117 - Per GL - AML	(620,535,830)	(616,592)	(1,375,461)	(126,569,797)	(35,069,518)	(4,775,601)	(60,560,225)	(155,349,951)	~~(236,198,665)~~	
186000 - Per GL - Prepaid Pension Asset	330,390,340	1,891,101	(31,218)	116,199,590	48,832,915	4,707,741	71,188,145	87,602,066	0	
[redacted]										
253024 - NIMO VERP	(217,004,187)								2 (217,004,187)	
253027 - Accrued Pension Expense	24,578,574								24,578,574	
253911 - Pension Rollforward - Contra	(4,790,587)								(4,790,587)	
182326 - Per GL - Regulatory Asset	252,218,019				56,358,753				~~195,958,266~~	
219010 - Per GL - OCI	188,841,313	371,497	1,312,316	123,463,581	0	4,637,035	59,056,884	0	0	
283117 - Per GL - DIT @39.75%	124,588,254	245,095	528,336	48,319,251	0	1,824,034	23,128,635	50,544,903	0	
Balance per GL @ 3/31/05	31,327,849	(1,911,932)	(38,362)	163,735,291	70,160,370	6,004,843	93,500,720	(94,400,435)	(205,722,647)	
Adjustments to GL -										
FY05 Pension Pymts debited to 253003	5,794,938		40,218	4,089	293,232	15,791	90,042	5,351,566		
FY03/04 Pension contrib debited to 253108	4,343,105							4,343,105		
Adjusted Balance Per GL	41,465,893	(1,911,932)	1,856	163,739,380	70,453,602	6,020,634	93,590,762	(84,705,764)	(205,722,647)	
VARIANCE	$ 4,952,108	$ 1,911,932	$ (1,856)	$ (163,739,380)	$ (70,453,602)	$ (6,020,634)	$ (93,590,762)	$ 335,518,253	$ 1,328,159	

Σ 1: ($196,932,556)

Σ 2: ($197,216,200)

Σ 1 (196,932,556)

Σ 2 (197,216,200)

→ also reclass the balance in 253024 to 253027

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P. 2

Exhibit ___ (P&O-5)

OPEB

New Window | Help | Customize Page |

Header | Lines | Totals | Errors | Approval

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	2	00036	~~692008~~ 129008	253106	-137,943.00	253106	

changed 18NNT

P. 4

Lines to add: 1

Totals Customize | Find | View All | First

Unit	Total Lines	Total Debits	Total Credits	Jourr
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Save Return to Search Next in List Previous in List Notify Refresh

Header | Lines | Totals | Errors | Approval

P. 3

NGUSA #

S:\GALOTUS\SMT\FAS106\[FAS106 rec - 3-31-05.xls]Cons Summa

Reconcile to 3/31/05 Hewitt liability balance

Summary - Dr / (CR)	Per Hewitt	Per GL	variance	
NE PBOP	(109,407,695)	(109,867,848)	460,153	DR A91070
NY PBOP	① (296,560,832)	② (296,422,889)	(137,943)	CR 692008
total	(405,968,527)	(406,290,737)	322,210	× 83% = $114,493
	0	0	0	

	Total	Nant Elec	Mass Elec	NEP	GS Elec	Narr Elec	Svc Co	NM
Nonunion balance per Hewitt	(303,513,314)	(208,320)	(32,222,740)	(7,383,575)	(1,351,177)	(12,077,615)	(49,999,141)	* P. 10 (200,270,746
FY05 Svc Co portion of NM							(3,646,731)	P. 13 3,646,731
FY04 Svc Co portion of NM							(2,391,836)	P. 14 2,391,836
Union balance per Hewitt	(62,461,502)	(454,678)	(10,347,686)	13,305,539	295,239	(4,701,652)	1,776,678	* (62,334,942 P. 9
Adjustments to Hewitt -								
FY03 PSC settlement - Interest Exp	(36,674,711)							P. 11 (36,674,711
Executive PBOP (NY, 242.05 134 ==	(3,319,000)							③ (3,319,000
ADJUSTED BALANCE PER HEWITT	(405,968,527)	(662,998)	(42,570,426)	5,921,964	(1,055,938)	(16,779,267)	(54,261,030)	① (296,560,832
Per GL @ 3/31/05	(401,934,178)	(666,682)	(42,383,218)	5,917,192	(1,048,415)	(16,834,751)	(50,495,414)	(296,422,889
09/05 entry to correct Nant's Wlkr activi	(13,454)	(13,454)						
reclass fy03/04 pension contrib	(4,343,105)						(4,343,105)	
ADJUSTED BALANCE PER GL	(406,290,737)	(680,136)	(42,383,218)	5,917,192	(1,048,415)	(16,834,751)	(54,838,519)	② (296,422,889
VARIANCE	322,210	17,138	(187,208)	4,772	(7,523)	55,484	577,489	(137,943

③ Liability for executive staff recorded @ merger closing, not adjusted as of 3/31/05

<CR> liab

NE only

DR 253106 460,152
CR. A91070 B01 <460,152>

NY

DR A91070 B01
CR 253106

* See attached 4/25/05 letter from Hewitt

P. 4

D. 41

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Exhibit (R&O-5) Page 4 of 17

May 27, 2005

Private and Confidential

Mr. William R. Richer
National Grid USA
25 Research Drive
Westboro, MA 01582

Dear Bill:

Subject: Estimated Pension/Retiree Welfare Expense for Fiscal Year 2006

As requested, we have estimated fiscal year 2006 expense for National Grid USA's pension and retiree welfare plans. Estimates reflect the new definition of covered earnings within the Niagara Mohawk Pension Plan and are based on a 5.75 percent discount rate assumption for US GAAP and UK GAAP purposes. Also, retiree welfare IAS 19 expense estimates are based on an April 1, 2004 adoption date which does not incorporate the liability reduction associated with the new prescription drug law change under the Medicare Act of 2003.

Below are fiscal year 2006 expense estimates for the pension and retiree welfare plans. Please note that we have not included any estimated settlement accounting charges. Also, we have included the annual regulatory expense charges for US GAAP purposes only:

Estimated Fiscal Year 2006 Expense/(Income) ($ Millions)

	US GAAP FAS 87	UK GAAP IAS 19
National Grid USA		
Qualified Pension	$ 10.0	$ 1.4
Nonunion Retiree Welfare	26.2	15.7
Union Retiree Welfare	17.1	8.5
Nonqualified Pension	8.1	6.4
New England Total	$ 61.4	$ 32.0
Niagara Mohawk		
Qualified Pension	$ 91.6	$ 42.8
Nonunion Retiree Welfare	46.0	21.2
Union Retiree Welfare	79.1	34.9
Nonqualified Pension	0.5	0.4
New York Total	$ 217.2	$ 99.3
One-time Charge	$ 0.0	$ 0.0
Grand Total	$ 278.6	$ 131.3

Mr. William R. Richer
Page 2
May 27, 2005

In determining our estimates we have used a 10.00 percent medical trend assumption for 2005 grading down to an ultimate trend rate of 5.0 percent. Also, we have used the UP94 Mortality Table as well as the following assumptions:

- 5.0 percent salary increase for nonunion employees
- 3.5 percent salary increase for union employees
- 8.25 percent expected return on assets for pension expense
- 6.75 percent expected return on assets for nonunion retiree welfare expense
- 8.50 percent expected return on assets for union retiree welfare expense

Enclosed are summaries by plan and by company.

Bill, please call if you have any questions.

Sincerely,

Hewitt Associates LLC

Stephen F. Doucette

SFD:jla
Enclosures
4844L276
cc: Mr. Edward A. Capomacchio, Jr., National Grid USA
Mr. John G. Cochrane, National Grid USA
Ms. Kristin DeSousa, National Grid USA
Mr. William F. Dowd, National Grid USA
Ms. Nancy B. Kellogg, National Grid USA
Ms. Mari-Louise Messuri, National Grid USA
Ms. Suzette E. Moreau, National Grid USA
Mr. Matthew J. Powers, National Grid USA
Ms. Susan Toronto, National Grid USA
Ms. Lisa M. VanDermark, Hewitt Associates

National Grid USA
Niagara Mohawk Pension Plan
Estimated FAS 87 Expense

	Actual 4/2004-3/2005	Estimated * 4/2005-3/2006
Reconciliation of Funded Status, 4/1		
Projected Benefit Obligation	$(1,307,185,517)	$ (1,369,848,000)
Fair Value of Assets	845,899,959	830,468,956
Funded Status	$ (461,285,558)	$ (539,379,044)
Unrecognized:		
• Net Transition Obligation or (Asset)	$ 0	$ 0
• Prior Service Cost	10,989,542	40,339,419
• Net (Gain) or Loss	239,118,862	307,987,794
(Accrued) / Prepaid Pension Cost	$ (211,177,154)	$ (191,051,831)
Net Periodic Pension Cost		
Service Cost	$ 29,323,724	$ 34,261,000
Interest Cost	70,576,110	75,604,000
Expected Return on Assets	(67,787,424)	(67,277,000)
Amortization of:		
• Net Transition Obligation or (Asset)	0	0
• Prior Service Cost	1,851,126	3,454,000
• Net (Gain) or Loss	26,226,836	35,366,000
FAS 87 Pension Expense	$ 60,190,372	$ 81,408,000
FAS 88 Settlement Expense	$ 0	$ 0
FAS 88 Special Termination Benefits	$ 0	$ 0
Regulatory Expense	$ 10,238,400	$ 10,238,400
Total Pension Expense	$ 70,428,772	$ 91,646,400
Expected Benefit Payments	$ 175,000,000	$ 110,000,000
Expected Contributions	$ 85,000,000	$ 80,000,000
Market Related Value of Assets	$ 838,986,453	$ 829,433,018
Assumptions:		
Discount Rate	5.75%	5.75%
Expected Return on Assets	8.50%	8.25%
Salary Scale	3.25%	3.90%
Mortality Table	83GAM	UP94

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* Reflects 10/31/04 union amendment and 3/31/2005 nonunion amendment

Hewitt Associates

National Grid USA
Niagara Mohawk Pension Plan
Estimated FAS 87 Expense

	Actual 4/2004-3/2005	Estimated 4/2005-3/2006
Net Periodic Pension Cost		
Niagara Mohawk Pension Plan		
Niagara Mohawk	$ ~~65,988,886~~	$ 85,973,777
NGUSCO	$ 4,439,886	$ 5,672,623
Total FAS 87/88 Expense	**$ 70,428,772**	**$ 91,646,400**

Assumptions:		
Discount Rate	5.75%	5.75%
Expected Return on Assets	8.50%	8.25%
Salary Scale	3.25%	3.90%
Mortality Table	83GAM	UP94

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Niagara Mohawk
Union Retiree Welfare Plan
Estimated FAS 106 Expense

	Actual 4/2004-3/2005	Estimated * 4/2005-3/2006
Reconciliation of Funded Status, 4/1		
Accumulated Postret. Ben. Obligation	$ (681,498,554)	$ (852,342,000)
Fair Value of Assets	489,889,609	477,947,685
Funded Status	$ (191,608,945)	$ (374,394,315)
Unrecognized:		
• Net Transition Obligation or (Asset)	$ 0	$ 0
• Prior Service Cost	0	149,868,171
• Net (Gain) or Loss	159,668,939	162,191,202
(Accrued) / Prepaid Cost	$ (31,940,006)	$ (62,334,942)
Net Periodic Cost		
Service Cost	$ 8,681,995	$ 14,584,000
Interest Cost	40,484,574	47,911,000
Expected Return on Assets	(39,252,270)	(39,002,000)
Amortization of:		
• Net Transition Obligation or (Asset)	0	0
• Prior Service Cost	6,180,640	14,834,000
• Net (Gain) or Loss	14,299,997	19,180,000
FAS 106 Expense	**$ 30,394,936**	**$ 57,507,000**
One-tine FAS 106 Expense	$ 0	$ 0
Regulatory Expense	$ 21,554,094	$ 21,554,000
Total RW Expense	**$ 51,949,030**	**$ 79,061,000**
Expected Benefit Payments	$ 36,400,000	$ 38,200,000
Expected Contributions	$ 0	$ 23,300,000
Market Related Value of Assets	$ 489,889,609	$ 477,947,685
Assumptions:		
Discount Rate	5.75%	5.75%
Expected Return on Assets	8.50%	8.50%
Initial Trend	10.00%	10.00%
Ultimate Trend	5.00%	5.00%
Mortality Table	83GAM	UP94

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* Reflects 10/31/04 union amendment

Hewitt Associates

Niagara Mohawk
Nonunion Retiree Welfare Plan
Estimated FAS 106 Expense

	Actual 4/2004-3/2005	Estimated * 4/2005-3/2006
Reconciliation of Funded Status, 4/1		
Accumulated Postret. Ben. Obligation	$ (420,778,321)	$ (415,779,000)
Fair Value of Assets	99,588,062	111,969,129
Funded Status	$ (321,190,259)	$ (303,809,871)
Unrecognized:		
• Net Transition Obligation or (Asset)	$ 0	$ 0
• Prior Service Cost	(3,081,645)	(2,815,985)
• Net (Gain) or Loss	125,796,597	106,355,110
(Accrued) / Prepaid Cost	$ (198,475,307)	$ (200,270,746) p.4
Net Periodic Cost		
Service Cost	$ 4,478,392	$ 5,204,000
Interest Cost	22,402,893	23,258,000
Expected Return on Assets	(6,546,145)	(7,037,000)
Amortization of:		
• Net Transition Obligation or (Asset)	0	0
• Prior Service Cost	(265,660)	(266,000)
• Net (Gain) or Loss	10,009,831	13,004,000
FAS 106 Expense	**$ 30,079,311**	**$ 34,163,000**
One-time FAS 106 Expense	$ 0	$ 0
Regulatory Expense	$ 11,863,106	$ 11,863,000
Total RW Expense	**$ 41,942,417**	**$ 46,026,000**
Expected Benefit Payments	$ 21,600,000	$ 22,600,000
Expected Contributions	$ 27,600,000	$ 38,000,000
Market Related Value of Assets	$ 99,588,062	$ 111,969,129
Assumptions:		
Discount Rate	5.75%	5.75%
Expected Return on Assets	7.25%	6.75%
Initial Trend	10.00%	10.00%
Ultimate Trend	5.00%	5.00%
Mortality Table	83GAM	UP94

* Does not reflect possible plan amendment to remove Cap for a closed group of retirees

Hewitt Associates

NM

PSC Staff Adj'ts

Interest charged

Toronto, Susan M.

From: Allen, James H. (NE - WBRO)
Sent: Thursday, November 17, 2005 10:58 AM
To: Toronto, Susan M.
Cc: Molloy, James M.
Subject: RE: Interest in Accrued Pension and FAS106

Sue,
Accrued interest included in pension and FAS 106, per internal reserve calc., by year are as follows:

	Pension	FAS 106	Total
03\31\03	$ 48,202	$180,448	
03\31\04	205,748	63,876	
03\31\05	75,447	19,387	
Total interest	$329,397	$263,711	$ 593,108
Add: original settlement	$13,825,000	$36,411,000	$50,236,000
Total	$14,154,397 $14,154,397 p. 2	$36,674,711 p. 4	$50,829,108

-----Original Message-----
From: Toronto, Susan M.
Sent: Thursday, November 17, 2005 7:20 AM
To: Allen, James H. (NE - WBRO)
Subject: Interest in Accrued Pension and FAS106

Hi Jim -

Can you give me the breakdown of the $50.8m that is included in Accrued Pension and Accrued FAS106 at 3/31/05, 3/31/04 and 3/31/03. I have the breakdown of the original settlement of $50,236,000 from Bill ($13,825,000 in Accrued Pension and $36,411,000 in Accrued FAS106) but I'm not sure how to get to the amounts that were booked relating to accrued interest going forward.

Thanks - Sue

Susan Toronto
Accounting Services
508-389-2684

National Grid USA
Niagara Mohawk Qualified Pension Plan
March 31, 2004 FAS 87 Disclosure

from Hewitt's 4/28/04 Letter

	Niagara Mohawk	National Grid USA Service Co.	Total Niagara Mohawk
Net Periodic Pension Cost, 4/1/2003 - 3/31/2004			
1. Service Cost	$ 25,816,888	$ 2,276,285	$ 28,093,173
2. Interest Cost	71,791,642	2,553,961	74,345,603
3. Expected Return on Assets	(68,938,127)	(2,452,449)	(71,390,576)
4. Net Amortization and Deferral			
i Net Transition Obligation	0	0	0
ii Prior Service Cost	1,120,593	39,865	1,160,458
iii Net (Gain)/Loss	17,377,831	618,210	17,996,041 $50,204,699 - p. 12-a
5. Settlement (Gain)/Loss	20,778,159	797,914	21,576,073
6. Net Periodic Pension Cost/(Income) 1 + 2 + 3 + 4 + 5	$ 67,946,986	$ 3,833,786 p. 2	$ 71,780,772
Special Termination Benefits	14,300,090	0	14,300,090

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Exhibit ___ (P&O-5)
Page 12 of 15

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National Grid USA
Niagara Mohawk Pension Plan
FAS 88 Settlement Accounting - 3/31/2004

	4/1/2003	12/31/2003	12/31/2003 Change due to Lump Sum Settlement	12/31/2003	3/31/2004	3/31/2004 Change due to Lump Sum Settlement	3/31/2004
Reconciliation of Funded Status							
Projected Benefit Obligation	$ (1,272,543,370)	$ (1,373,041,529)	$ 125,241,008	$ (1,247,800,521)	$ (1,296,617,341)	$ 7,832,376	$ (1,288,784,965)
Fair Value of Assets	737,593,163	960,641,008	(125,241,008)	835,400,000	853,732,335	(7,832,376)	845,899,959
Funded Status	$ (534,950,207)	$ (412,400,521)	$ 0	$ (412,400,521)	$ (442,885,006)	$ 0	$ (442,885,006)
Unrecognized:							
• Net Transition Obligation	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0
• Prior Service Cost	12,150,000	11,279,656	0	11,279,656	10,989,542	0	10,989,542
• Net (Gain) or Loss	309,303,915	221,836,889	(20,234,694)	201,602,195	222,059,689	(1,341,379)	220,718,310
(Accrued) / Prepaid Pension Cost	$ (213,496,292)	(179,283,976)	$ (20,234,694)	$ (199,518,670)	(209,835,775)	$ (1,341,379)	$ (211,177,154)
Net Periodic Pension Cost	**4/1/03 - 12/31/03**			**1/1/04 - 3/31/04**			**Total Expense**
Service Cost	$ 20,872,623			$ 7,220,550			$ 28,093,173
Interest Cost	56,603,595			17,742,008			74,345,603
Expected Return on Assets	(54,916,399)			(16,474,177)			(71,390,576)
Amortization of:							
• Net Transition Obligation	0			0			0
• Prior Service Cost	870,344			290,114			1,160,458
• Net (Gain) or Loss	13,057,431			4,938,610			17,996,041
FAS 87 Pension Expense	$ 36,487,594			$ 13,717,105			$ 50,204,699 ← p. 12
Est. FAS 88 Pension Expense - Settlement			$ 20,234,694			$ 1,341,379	$ 21,576,073
Est. FAS 88 Pension Expense - VERO		$ 14,300,090					$ 14,300,090
Regulatory Expense	$ 7,678,800			$ 2,559,600			$ 10,238,400
Total Pension Expense	$ 44,166,394	$ 14,300,090	$ 20,234,694	$ 16,276,705	$ 0	$ 1,341,379	$ 96,319,262
Assumptions:							
Discount Rate	6.25%	6.00%		6.00%	5.75%		
Expected Return on Assets	8.50%	8.50%		8.50%	8.50%		
Salary Scale	3.25%	3.25%		3.25%	3.25%		
Market Related Value of Assets	$ 873,595,593			$ 840,255,376			
Expected Contributions	$ 85,000,000			$ 3,400,000			
Total Benefit Payments	$ 165,978,985			$ 21,401,077			
Lump Sum Payments	$ 125,241,008			$ 7,832,376			

Hewitt Associates

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p. 12-a

November 12, 2004

Private and Confidential

Mr. William R. Richer
National Grid USA
25 Research Drive
Westboro, MA 01582

Dear Bill:

Subject: Updated Niagara Mohawk FAS 106 and SSAP 24 Expense Results – April 1, 2004 through March 31, 2005

We have updated the 2004/2005 FAS 106 and SSAP 24 valuation results for the Niagara Mohawk Retiree Welfare Plans to incorporate the recently ratified union contract.

Expense for fiscal year April 1, 2004 through March 31, 2005 is based on a 5.75 percent discount rate assumption, a 10 percent initial medical trend rate assumption, and a 5.00 percent ultimate medical trend rate assumption. The valuation results also reflect the Medicare Act of 2003.

The significant changes associated with the new union contract are:

- Pre 65 Medical Coverage: The employer contribution cap has been eliminated for employees retiring after October 1, 2004 and an 80/20 percent cost sharing has been implemented.
- Post 65 Medical Coverage: The employer contribution cap has been eliminated for employees retiring after October 1, 2004 and a 75/25 percent cost sharing has been implemented.

Total expense for fiscal year 2005 is $93.9 million, including regulatory expense. This represents a $14.4 million increase over our preliminary results (October 5, 2004 letter). This change is attributable to the new union contract, prorated for the five month period November 1, 2004 through March 31, 2005.

	Fiscal 2005 FAS 106 Expense
Union Niagara Mohawk	$ 52.0 million
Nonunion Niagara Mohawk	38.3 million
Service Company	3.6 million
Total	$ 93.9 million

-> $3,646,731
p. 4

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Niagara Mohawk
Nonunion Retiree Welfare Plan
Estimated FAS 106 and SSAP 24 Expense

	Actual 4/2002-3/2003	Actual 4/2003-3/2004	Estimated 4/2004-3/2005
Net Periodic Cost			
Niagara Mohawk	$ 29,659,380	$ 39,482,483	$ 41,844,000
NGUSCO	$ 0	$ 2,391,836	$ 2,458,000
Total FAS 106 Expense	**$ 29,659,380**	**$ 41,874,319**	**$ 44,302,000**

P. 4

Assumptions:			
Discount Rate	7.50%	6.25%	5.75%
Expected Return on Assets	7.50%	7.25%	7.25%
Initial Trend	10.00%	10.00%	10.00%
Ultimate Trend	5.00%	5.00%	5.00%
Actual Return on Assets for Projection	-8.16%	22.73%	7.25%
Number of Employees Accepting ERW	0	73	0

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Exhibit__(P&O-6)

Date of Request__9/7/06_ Request No. _PSC-355 Gerbsch (DAG-42)__

NMPC Req. No. _419_

NIAGARA MOHAWK POWER CORPORATION
Case 01-M-0075 – Second CTC Reset Compliance Filing
Request for Information

FROM: PSC-355 Gerbsch (DAG-42)___

Request:

1. In the Company's response to I/R #PSC-323 (DAG-39), dated July 20, 2006, as it relates to non-union FAS 106 expense, the Company provides for FYE 3/06 the following: (a) total NM OPEB expense amount of $33,322,910 and (b) OPEB expense originally allocated to service company amount of $3,872,117. Subsequently on 8/24/06, the Company provided to Staff, via fax, a six page document (one cover sheet and five pages with a fax date of 4/27/06 from Hewitt Associates to National Grid), of which two pages contain information on the Niagara Mohawk Nonunion Retiree Welfare Plan for FYE 3/06. The one relevant column on the two pages is labeled, "Actual 4/2005-3/2006," and shows the annual FAS 106 expense of $33,322,910 and reg asset amortization expense of $11,863,106 for a total expense of $45,186,016. Of this, $4,580,859 is allocated to the National Grid USA Service Company (NGUSCO).

Based on the Company's response to PSC-280, question #6, "The amortization of the regulatory asset has been and will continue to be allocated to Niagara Mohawk," i.e none of the amortization of the regulatory asset is allocated to the service company. Based on this statement, for FYE 3/06, the $4,580,859 allocated to the Service Co is a portion of the annual expense amount of $33,322,910.

Please reconcile the amounts for FYE 3/06 OPEBs expense "Allocated to Service Company" as shown in the Company's response to PSC-323 (DAG-39) to the 4/27/06 faxed Hewitt report, and explain any discrepancies and include supporting workpapers

Response:

In both its September 2005 and March 2006 letters related to FY 2006 OPEB expense, Hewitt included an allocation of the regulatory asset to Service Company in error. Hewitt presents the regulatory amortization for informational purposes. The Company does not rely on the regulatory amortization amounts shown on Hewitt's expense letters for its booking of regulatory amortization. The Company actually booked its OPEB regulatory expense for FY 2006 according to the established amortization schedule provided with its response to IR PSC-150 with no allocation to Service Company. The Company relies on the actuary for the indicated FAS 87 and FAS 106 expense, but not the regulatory amortization, which is not a type of pension or OPEB expense that falls under the guidelines of those standards. The OPEB expense booked for FY 2006 agrees with the amount included in Hewitt's March 2006 letter. Please see the attached reconciliation.

Name of Respondent:
James Molloy
William Richer

Date of Reply:
September 15, 2006

Form 103

PSC-355
OPEB Reconciliation

HEWITT

	NMPC	Service Company	Total
Regulatory Amortization	32,708,458.00	708,742.00	33,417,200.00
OPEB Expense	84,798,689.00	3,872,117.00	88,670,806.00
Total	117,507,147.00	4,580,859.00	122,088,006.00

COMPANY

	NMPC	Service Company	Total	
Regulatory Amortization	33,698,016.87	-	33,698,016.87	
OPEB Expense	84,798,689.00	3,872,117.00	88,670,806.00	(1)
Total	118,496,705.87	3,872,117.00	122,368,822.87	

DIFFERENCE

	NMPC	Service Company	Total	
Regulatory Amortization	(989,558.87)	708,742.00	(280,816.87)	
OPEB Expense	-	-	-	
Total	(989,558.87)	708,742.00	(280,816.87)	(2)

(1) In order to compare with Hewitt's numbers above, the NMPC OPEB expense amount shown here does not include a $138,000 reconciling adjustment included with the 2/02 expense amount booked.

(2) Difference is due to the regulatory expense amortization. Hewitt calculates using 120 month amortization schedule. The Company calculates using 119 months.

Exhibit___(P&O-7)

OPEB Detailed Reconciliation

September 20, 2006 Testimony

□E□ITT	NMPC	Service Company	Total		Electric Only NMPC	Service Company	Total
Regulatory Amortization	32,708,458	708,742	33,417,200		27,148,020	588,256	27,736,276
OPEB Expense	84,798,689	3,872,117	88,670,806		70,382,912	3,213,857	73,596,769
Total	117,507,147	4,580,859	122,088,006		97,530,932	3,802,113	101,333,045

COMPANY	NMPC	Service Company	Total		Electric Only NMPC	Service Company	Total
Regulatory Amortization	33,698,017	-	33,698,017		27,969,354		27,969,354
OPEB Expense	84,936,930	3,872,117	88,809,047	(1)	70,497,652	3,213,857	73,711,509
Total	118,634,947	3,872,117	122,507,064		98,467,006	3,213,857	101,680,863

DIFFERENCE	NMPC	Service Company	Total		Electric Only NMPC	Service Company	Total
Regulatory Amortization	(989,559)	708,742	(280,817)	(2)	(821,334)	588,256	(233,078)
OPEB Expense	(138,241)	-	(138,241)	(3)	(114,740)		(114,740)
Total	(1,127,800)	708,742	(419,058)		(936,074)	588,256	(347,818)
Less 119 verse 120 months amortization difference					(233,078)		
Total NMPC Electric Difference					(702,996)		

(1) Includes a $137,943 reconciling adjustment included with the 2/02 expense amount booked.

(2) Difference is due to the regulatory expense amortization. Hewitt calculates using 120 month amortization schedule. The Company calculates using 119 months.

(3) Difference stems from the 2/06 reconciling entry noted in (1) above

Exhibit ___(P&O-8)

Calculation of Associated Billings Pre-ERP (OPEB)

Fiscal Period	Cost Component	Amount	OPEB Ratio	OPEB Dollars
03/31/2002	220	53,280.54	17.28%	9,206.88
04/30/2002	220	59,792.74	17.28%	10,332.19
05/31/2002	220	33,750.25	17.28%	5,832.04
06/30/2002	220	53,263.75	17.28%	9,203.98
07/31/2002	220	50,740.44	17.28%	8,767.95
08/31/2002	220	39,149.16	17.28%	6,764.97
09/30/2002	220	24,321.21	17.28%	4,202.71
10/31/2002	220	19,537.88	17.28%	3,376.15
11/30/2002	220	26,176.47	17.28%	4,523.29
12/31/2002	220	22,381.99	17.28%	3,867.61
01/31/2003	220	24,947.80	17.28%	4,310.98
02/28/2003	220	24,501.20	17.28%	4,233.81
03/31/2003	220	16,591.67	17.28%	2,867.04
04/30/2003	220	22,662.07	29.49%	6,683.04
05/31/2003	220	41,915.23	29.49%	12,360.80
06/30/2003	220	38,956.23	29.49%	11,488.19
07/31/2003	220	39,237.86	29.49%	11,571.24
08/31/2003	220	30,050.79	29.49%	8,861.98
09/30/2003	220	53,084.88	29.49%	15,654.73
10/31/2003	220	37,972.06	29.49%	11,197.96
11/30/2003	220	41,859.02	29.49%	12,344.22
12/31/2003	220	52,795.18	29.49%	15,569.30
01/31/2004	220	225,781.62	29.49%	66,583.00
02/29/2004	220	192,745.79	29.49%	56,840.73
03/31/2004	220	241,544.53	29.49%	71,231.48
04/30/2004	220	181,002.20	29.49%	53,377.55
Total				431,253.83

Calculation of Associated Billings Pre-ERP (Pension)

Fiscal Period	Cost Component	Amount	Pension Ratio	Pension Dollars
03/31/2002	220	53,280.54	15.24%	8,119.95
04/30/2002	220	59,792.74	15.24%	9,112.41
05/31/2002	220	33,750.25	15.24%	5,143.54
06/30/2002	220	53,263.75	15.24%	8,117.40
07/31/2002	220	50,740.44	15.24%	7,732.84
08/31/2002	220	39,149.16	15.24%	5,966.33
09/30/2002	220	24,321.21	15.24%	3,706.55
10/31/2002	220	19,537.88	15.24%	2,977.57
11/30/2002	220	26,176.47	15.24%	3,989.29
12/31/2002	220	22,381.99	15.24%	3,411.02
01/31/2003	220	24,947.80	15.24%	3,802.04
02/28/2003	220	24,501.20	15.24%	3,733.98
03/31/2003	220	16,591.67	15.24%	2,528.57
04/30/2003	220	22,662.07	26.01%	5,894.40
05/31/2003	220	41,915.23	26.01%	10,902.15
06/30/2003	220	38,956.23	26.01%	10,132.52
07/31/2003	220	39,237.86	26.01%	10,205.77
08/31/2003	220	30,050.79	26.01%	7,816.21
09/30/2003	220	53,084.88	26.01%	13,807.38
10/31/2003	220	37,972.06	26.01%	9,876.53
11/30/2003	220	41,859.02	26.01%	10,887.53
12/31/2003	220	52,795.18	26.01%	13,732.03
01/31/2004	220	225,781.62	26.01%	58,725.80
02/29/2004	220	192,745.79	26.01%	50,133.18
03/31/2004	220	241,544.53	26.01%	62,825.73
04/30/2004	220	181,002.20	26.01%	47,078.67
Total				380,359.41

Exhibit___(P&O-9)

9/25/2006

Niagara Mohawk Power Corporation
Adjustment for Employees Transferred to the Service Company
During Fiscal Year (After Hewitt Valuation is done)

Niagara Mohawk Power Corportation
d/b/a National Grid
Case 01-M-0075 Second CTC Reset Deferral Audit
Exhibit ___ (P&O-9)

Pension Expense

From Company's Response to DAG-39 (NMPC-382)

	Column F	Column G				NMPC Adjustments to Staff Calculations		
	Decrease NM Pension Expense Change	Electric 83%	Staff Capital %	Decrease for Amount Capitalized	Revised Staff Adj	Svc Co Allocation % to NM	NM Share of Serv Co Allocation	Staff Adj Revised
FYE 3/31/04	(298,218)	(247,521)	23.95%	(59,281)	(188,240)	26.09%	(49,112)	(139,128)
FYE 3/31/05	(84,220)	(69,903)	26.04%	(18,203)	(51,700)	29.20%	(15,096)	(36,604)
FYE 3/31/06	(253,942)	(210,772)	26.18%	(55,180)	(155,592)	31.09%	(48,374)	(107,218)
Total Staff Pension Adj	(636,380)	(528,195)		(132,664)	(395,531)		(112,582)	(282,950)
Through June '05					(278,838)			(202,536)
July '05 through December' 05					(77,796)			(53,609)
January '06 through March '06					(38,898)			(26,805)
Total					395,531			(282,950)

OPEBs Expense

From Company's Response to DAG-39 (NMPC-382)

	Column F	Column G				NMPC Adjustments to Staff Calculations		
	Decrease NM OPEBs Expense Change	Electric 83%	Staff Capital %	Decrease for Amount Capitalized	Revised Staff Adj	Svc Co Allocation % to NM	NM Share of Serv Co Allocation	Staff Adj Revised
FYE 3/31/04	(209,299)	(173,718)	23.95%	(41,606)	(132,113)	24.27%	(32,064)	(100,049)
FYE 3/31/05	(69,174)	(57,414)	26.04%	(14,951)	(42,464)	28.78%	(12,221)	(30,243)
Total Staff Pension Adj	(278,473)	(231,133)		(56,556)	(174,576)		(44,285)	(130,292)
FYE 3/31/06	**(72,602)**	**(60,260)**	**26.18%**	**(15,776)**	**(44,299)**	**31.01%**	**(13,737)**	**(30,562)**
(From Company's response to DAG-39 (NMPC-382)								
Total OPEB Adj					(218,875)		(58,022)	(160,853)
Through June '05					(185,651)			(137,932)
July '05 through December' 05					(22,150)			(15,281)
January '06 through March '06					11,075			(7,640)
Total					(196,726)			(160,853)

Exhibits of James J. Bonner Jr. and Lee A. Klosowski

Exhibit___(JJB/LAK-1)

nationalgrid

Carlos A. Gavilondo
General Counsel, New York Distribution

September 21, 2006

Honorable Jeffrey E. Stockholm
Administrative Law Judge
NYS Department of Public Service
3 Empire State Plaza
Albany, New York 12223

Re: **<u>Request for Trade Secret/ Confidential Protection –</u>**
Case 01-M-0075, Second CTC Reset Compliance Filing,
Niagara Mohawk Power Corporation
Response to Information Request No. NMPC-422, PSC-358, RAV-131
Request for Confidential Treatment of Customer Information

Dear Judge Stockholm:

Pursuant to 16 NYCRR § 6-1 et seq. and Sections 87 and 89 of the Public Officers Law, Niagara Mohawk Power Corporation, d/b/a National Grid ("Company") hereby submits this request for trade secret/confidential treatment. The Company requests trade secret/confidential treatment for confidential customer information including the customer name and account information (the redacted information hereinafter referred to as "Confidential Information"). This information is being provided in connection with the Company's response to the above referenced Information Request ("IR") from Department of Public Service Staff ("Staff") in Case 01-M-0075 Second CTC Reset Compliance Filing. As set forth herein, the Confidential Information being provided herewith qualifies for exemption from public disclosure as set forth in the Freedom of Information Law ("FOIL"). N.Y. Pub. Off. Law § 87 (Supp. 2005); See also 16 NYCRR § 6-1.3.

Trade secret and confidential protection is warranted "if disclos[ure] would cause substantial injury to the competitive position of the subject enterprise." N.Y. Pub. Off. Law § 87(2)(d) (Supp. 2005); See also 16 NYCRR § 6-1.3. In determining whether information should be considered for confidential treatment, the Commission's regulations set forth six non-exclusive factors:

1. the extent to which disclosure would cause unfair economic or competitive damage;
2. the extent to which the information is known by others;
3. the value of the information to the possessor of the data and its competitors;
4. the difficulty and cost of developing the information;
5. the difficulty in recreating the data without permission; and
6. whether the data is otherwise exempted by law from disclosure.

16 NYCRR § 6-1.3(b)(2).

The Confidential Information is not available to the public at large. If this information (customer name and account information) was made public, then any party examining the

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response to this information request could have insight into the usage and billing information about the individual customers. This is information which could be used by a customer's competitors to determine the customer's electricity usage levels and pattern, which could provide a competitor with a competitive advantage. This information could also be used by energy service companies or other marketing entities that would otherwise not have access to this information without the consent/permission of the customers thereby constituting an unwarranted invasion of personal privacy. *See* Pub. Off. Law § 89(2)(b). Disclosure of the information could also competitively damage the Company by disclosing account information that could be used by others to commit fraud or unlawfully gain access to the Company's customer systems or to give a party access to information that could be used to their competitive advantage when dealing with the Company. Typically, this type of customer-specific information is not publicly released by the Company absent customer authorization to do so, and the Company takes steps to protect such customer-specific information and treat it confidentially.

The non-exclusive factors listed in 16 NYCRR § 6-1.3 (b)(2) militate in favor of granting confidential treatment and protecting the information from public disclosure. Accordingly, the Company respectfully requests that trade secret/confidential status be granted to the Confidential Information.

For your information, unredacted versions of the response which show the Confidential Information are being provided directly to Robert Visalli, Denise Gerbsch, and Patrick Piscitelli of the Staff. The Company will advise these Staff members that it is seeking protection for the Confidential Information, and advise them to protect the Confidential Information pursuant to Section 6-1.3(d) of the regulations pending further direction from you in that regard. The Company has confirmed with counsel's office at the Department of Public Service that this process is acceptable and will not harm the Company's request for trade secret/confidential treatment.

Thank you for your attention to this matter.

Respectfully submitted,

Carlos A. Gavilondo

Date of Request_9/15/06__ Request No. __PSC-358 Visalli (RAV-131)_

NMPC Req. No. _422_

NIAGARA MOHAWK POWER CORPORATION
Case 01-M-0075 – Second CTC Reset Compliance Filing
Request for Information

FROM: PSC-358 Visalli (RAV-131)__

Request:

On page 10 lines 1-4 of the Bonner / Klosowski panel testimony, it is stated that "the CSBC deferrals of $10.3 million for the first three years of PowerChoice that Staff accepts without adjustment include deferral of CSBC due to Direct Customers"

Regarding this statement, please provide the CSBCs by Direct Customer by month for each of the first three years of PowerChoice that are included in the $10.3 million CSBC deferral balance as of December 31, 2001.

Response:

The Customer Service Backout Credits ("CSBC") by customer by month given to Direct Customers during the first three years of PowerChoice (09/01/1998-08/31/2001) are shown on the Attachment to this Response. Since Direct Customers did not exist prior to the creation of the New York Independent System Operator ("NYISO") in November 1999, the first Direct Customers began receiving CSBC in December 1999. As shown on page 3 of the Attachment, CSBC deferrals attributable to Direct Customers equaled $1,367,010 during the first three years of PowerChoice, 13.3% of the total $10,309,579 CSBC deferred over that period.[1]

Name of Respondent:
James J. Bonner Jr. & Lee A. Klosowski

Date of Reply:
September 21, 2006

[1] In accordance with PSC 207 Electricity Tariff Rule No. 42.3.1 in effect from September 1, 1998 through August 31, 2001: "The Company shall defer fifty percent (50%) of the actual credits distributed in each year up to the yearly limits [specified in Rule 42.4]. Additionally, any amounts in excess of the yearly limits up to $500,000 in each year shall be deferred." Rule 42.4 yearly limits were not exceeded in any year of PowerChoice.

Form 103

DIRECT CUSTOMERS CSBC
POSTINGS IN CSS
NOV 1999 - AUG 2001

ESCO CODE	ESCO NAME	199912	200001	200002	200003	200004	200005	200006	200007	200008
[redacted]	[redacted]	-1.51	-9,992.04	-22,519.96	-34,102.66	-34,099.44	-27,326.35	-30,605.30	-28,035.66	-25,098.35
[redacted]	[redacted]	-100.81	-13,568.39	-4,870.03	-5,857.90	-32,788.77	-10,275.44	-13,534.92	-18,117.31	-12,850.08
[redacted]	[redacted]	-1,112.70	-24,476.73	-15,964.28	-24,844.87	-38,095.50	-27,085.94	-30,865.20	-29,317.99	-30,308.44
[redacted]	[redacted]		-42,768.40	-42,137.47	-38,421.42	-30,848.16	-32,241.04	-30,145.42	-27,932.50	-28,117.18
[redacted]	[redacted]									
[redacted]	[redacted]	-5,861.42	-34,570.66	-2,196.65	-34,585.00	-40,980.92	-27,248.37	-30,412.59	-29,446.80	-27,283.89
[redacted]	[redacted]							-7.79	-5.57	-4.95
[redacted]	[redacted]									
[redacted]	[redacted]									
Total		**-7,076.44**	**-125,376.22**	**-87,688.39**	**-137,811.85**	**-176,812.79**	**-124,177.14**	**-135,571.22**	**-132,855.83**	**-123,662.89**

DIRECT CUSTOMERS CSBC
POSTINGS IN CSS
NOV 1999 - AUG 2001

ESCO CODE	ESCO NAME	200009	200010	200011	200012	200101	200102	200103	200104	200105
[redacted]	[redacted]	-24,639.29	-19,751.47	-20,094.77	-21,152.21	-23,794.97	-24,006.66	-29,353.29	-26,827.20	-19,418.69
[redacted]	[redacted]	-12,645.99	-12,164.40	-11,517.13	-12,679.76	-8,171.89	-16,363.71	-12,278.40	-12,387.53	-10,438.02
[redacted]	[redacted]	-31,019.61	-23,439.62	-22,766.37	-23,321.02	-6,812.41	-39,713.83	-28,405.64	-24,133.25	-24,266.14
[redacted]	[redacted]	-30,596.94	-30,729.70	-31,526.26	-35,061.36		-65,329.50	-38,417.63	-39,574.09	-33,009.20
[redacted]	[redacted]									-4,399.03
[redacted]	[redacted]	-22,396.30	-20,379.00	-18,105.12	-18,247.88	-18,886.04	-17,301.04	-89,465.34	-55,232.97	-23,961.56
[redacted]	[redacted]	-10.61	-7.59	-10.29	-10.11	-6.87	-8.91	-9.22	-7.74	-8.26
[redacted]	[redacted]			-10,902.36			-876.14	-34,119.91	-23,453.42	-35,927.23
[redacted]	[redacted]									
Total		**-121,308.74**	**-106,471.78**	**-114,922.32**	**-110,472.34**	**-57,674.18**	**-183,599.79**	**-232,049.43**	**-181,616.20**	**-151,428.14**

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Exhibit ____(JJB/LAK-1)
Page 5 of 6

DIRECT CUSTOMERS CSBC
POSTINGS IN CSS
NOV 1999 - AUG 2001

ESCO CODE	ESCO NAME	200106	200107	200108	Total
[redacted]	[redacted]	-20,033.01	-19,173.36	-18,666.96	**-478,693.15**
[redacted]	[redacted]	-11,745.44	-10,520.35	-9,984.02	**-252,860.29**
[redacted]	[redacted]	-27,262.13	-27,661.70	-31,713.81	**-532,587.18**
[redacted]	[redacted]	-28,123.98	-27,463.08	-29,008.91	**-681,452.26**
[redacted]	[redacted]	-5,081.30	-6,308.51	-6,638.87	**-22,427.71**
[redacted]	[redacted]	-33,199.60	-34,085.21	-27,738.29	**-611,584.64**
[redacted]	[redacted]	-8.42	-4.15	-3.39	**-115.89**
[redacted]	[redacted]	-26,032.58	-22,298.85	-616.70	**-154,227.19**
[redacted]	[redacted]			-71.22	**-71.22**
Total		**-151,486.46**	**-147,515.21**	**-124,442.17**	**-2,734,019.53**

times: Deferral Pct.	**50%**
Direct Customer CSBC Deferred	**-1,367,009.77**

Exhibit__(JJB/LAK-2)

Per IR No. 372 [PSC-313 Visalli (RAV 106) (Correction 2)]
CSBC to Direct Customers Other than Station Service Customers

Balance as of 5-2006	$	(11,851,239)
Less:		
Jul-2005		(284,389)
Aug-2005		(280,569)
Sep-2005		(284,435)
Oct-2005		(257,106)
Nov-2005		(256,485)
Dec-2005		(268,773)
Jan-2006		(247,322)
Feb-2006		(257,658)
Mar-2006		(291,055)
Apr-2006		(262,039)
May-2006		(238,576)
SUBTOTAL	$	(2,928,409)
CSBC @ 06/30/2005	$	(8,922,831)
times:		75%
CSBC Deferral @06/30/2005	$	(6,692,123)

nationalgrid

Carlos A. Gavilondo
General Counsel, New York Distribution

June 26, 2006

VIA OVERNIGHT DELIVERY

Mr. Steven R. Blow, Esq.
Records Access Officer
New York State Department of Public Service
Three Empire State Plaza
Albany, New York 12223

Re: Request for Trade Secret Protection –
Case 01-M-0075, Second CTC Reset Compliance Filing,
Niagara Mohawk Power Corporation
Response to IR No. NMPC-372, PSC-313, (RAV-106)
Corrected Response

Dear Mr. Blow:

Pursuant to 16 NYCRR § 6-1 et seq. and Sections 87 and 89 of the Public Officers Law, Niagara Mohawk Power Corporation, d/b/a National Grid ("National Grid" or "Company") hereby submits this request for confidential treatment of certain information provided in connection with the Company's response to the above-referenced Information Request ("IR"). In order to respond to the subject IR, the Company must provide certain customer-specific information, the public disclosure or which would be inappropriate. Accordingly, National Grid requests the Department of Public Service ("Department") deem these materials as confidential information, and take the necessary steps to safeguard against their disclosure as set forth in 16 NYCRR § 6-1.3.

This letter supplements a previously submitted request for trade secret and confidential information protection of even date related to this same IR. The basis for the submitting the corrected response was to delete a customer listing from the initial confidential response. Information on this customer was included in error in the initial response. The basis for the Company's request for confidential treatment is set forth below.

The IR in question seeks information relating to, *inter alia*, individual customer identity and the related customer service backout credits ("CSBC") provided to the customers. For purposes of this request, the Company refers to the customer identity and account information in the response as the "Confidential Information." National Grid believes that the Confidential Information being provided herewith qualifies for exemption from public disclosure as set forth in the Freedom of Information Law ("FOIL") and as provided in the Commission's regulations, and requests that the Confidential Information be treated as trade secret or confidential commercial information and protected from disclosure. N.Y. Pub. Off. Law § 87; 16 N.Y.C.R.R. § 6-1.3.

Trade secret and confidential protection is warranted "if disclos[ure] would cause substantial injury to the competitive position of the subject enterprise." N.Y. Pub. Off. Law §

87(2)(d) (Supp. 2005); *see also* 16 N.Y.C.R.R. § 6-1.3. In determining whether information should be considered for confidential treatment, the Commission's regulations set forth six non-exclusive factors:

1. the extent to which disclosure would cause unfair economic or competitive damage;
2. the extent to which the information is known by others;
3. the value of the information to the possessor of the data and its competitors;
4. the difficulty and cost of developing the information;
5. the difficulty in recreating the data without permission; and
6. whether the data is otherwise exempted by law from disclosure.

16 NYCRR § 6-1.3(b)(2).

The Confidential Information is not available to the public at large and the other parties to the above referenced proceeding are not being given access to the Confidential Information. The Confidential Information, combined with the information provided about the customers' respective CSBCs, could be used to calculate the energy usage of individual customers. This information could be used by a customer's competitors so as to determine the customer's energy usage. This information could also be used by energy service companies or other marketing entities that would otherwise not have access to this information without the consent/permission of the customers. Typically, this type of customer-specific information is not publicly released by the Company absent customer authorization to do so, and the Company takes steps to protect such customer-specific information and treat it confidentially.

The non-exclusive factors listed in 16 NYCRR § 6-1.3 (b)(2) militate in favor of granting confidential treatment and protecting the information public disclosure. Accordingly, the Company respectfully requests that confidential and/or trade secret status be granted to the Confidential Information.

For your information, unredacted versions of the Confidential Information will be provided directly to Robert Visalli, Denise Gerbsch, and Patrick Piscitelli of the Department of Public Service Staff at their Syracuse offices. Because of the large volume of information included, the Confidential Information is being provided on compact disk. Mr. Visalli, Ms. Gerbsch and Mr. Piscitelli will be advised to protect the Confidential Information from disclosure pursuant to Section 6-1.3(d) of the regulations. 16 NYCRR § 6-1.3(d). The Company will advise Mr. Visalli, Ms. Gerbsch and Mr. Piscitelli that it is seeking trade secret/confidential treatment for the Confidential Information provided to them and that they should expect further direction from you in that regard. The Company has spoken to counsel's office at the Department and confirmed that this process was acceptable and would not harm the Company's request for trade secret/confidential treatment.

Kindly acknowledge receipt and filing of this request by date-stamping the enclosed copy of this letter and returning it in the postage-paid envelope provided for your convenience.

Respectfully submitted,

Carlos A. Gavilondo

Enc.

Date of Request_6/19/06__ Request No. __PSC-313 Visalli (RAV-106)_CORRECTED

NMPC Req. No. _372_

NIAGARA MOHAWK POWER CORPORATION
Case 01-M-0075 – Second CTC Reset Compliance Filing
Request for Information

FROM: PSC-313 Visalli (RAV-106)___

Request:

Please provide the amount of customer service backout credits (CSBCs) given to Direct Customers other than Station Service Customers from 2/1/02 – 5/30/06[1]. The CSBC amounts should be provided by customer by month.

Corrected Response:

The customer service backout credits by customer by month given to Direct Customers other than Station Service Customers from 2/1/02 – 5/30/06 are provided in the Corrected Excel spreadsheet.

Name of Respondent: Mark Siegel Date of Reply: 6/26/06

[1] CSBCs for Station Service Customers are already being provided in response to IR RAV-34.

Form 103

ESCO_ID_CD	ESCO NAME	KY_BAS	Name	200202	200203	200204	200205	200206	200207	200208	200209	200210	200211	200212
0173	[redacted]	[redacted]	[redacted]									-248.40	-238.40	-276.00
0173	[redacted]	[redacted]	[redacted]										-181.80	-225.60
0174	[redacted]	[redacted]	[redacted]											
0174	[redacted]	[redacted]	[redacted]											
0174	[redacted]	[redacted]	[redacted]											
0174	[redacted]	[redacted]	[redacted]											
0174	[redacted]	[redacted]	[redacted]											
0174	[redacted]	[redacted]	[redacted]											
0174	[redacted]	[redacted]	[redacted]											
0174	[redacted]	[redacted]	[redacted]											
0174	[redacted]	[redacted]	[redacted]											
0174	[redacted]	[redacted]	[redacted]											
0174	[redacted]	[redacted]	[redacted]											
0174	[redacted]	[redacted]	[redacted]											
0174	[redacted]	[redacted]	[redacted]											
0174	[redacted]	[redacted]	[redacted]											
0174	[redacted]	[redacted]	[redacted]											
0174	[redacted]	[redacted]	[redacted]											
0174	[redacted]	[redacted]	[redacted]											
0174	[redacted]	[redacted]	[redacted]											
0174	[redacted]	[redacted]	[redacted]											
0174	[redacted]	[redacted]	[redacted]											
0174	[redacted]	[redacted]	[redacted]											
0174	[redacted]	[redacted]	[redacted]											
0185	[redacted]	[redacted]	[redacted]											
0182	[redacted]	[redacted]	[redacted]											
0182	[redacted]	[redacted]	[redacted]											
0182	[redacted]	[redacted]	[redacted]											
0231	[redacted]	[redacted]	[redacted]											
0231	[redacted]	[redacted]	[redacted]											
0231	[redacted]	[redacted]	[redacted]											
0231	[redacted]	[redacted]	[redacted]											
0231	[redacted]	[redacted]	[redacted]											
0231	[redacted]	[redacted]	[redacted]											
0231	[redacted]	[redacted]	[redacted]											
0245	[redacted]	[redacted]	[redacted]											
0245	[redacted]	[redacted]	[redacted]											
0245	[redacted]	[redacted]	[redacted]											
0245	[redacted]	[redacted]	[redacted]											
0245	[redacted]	[redacted]	[redacted]											
0245	[redacted]	[redacted]	[redacted]											
0245	[redacted]	[redacted]	[redacted]											
0245	[redacted]	[redacted]	[redacted]											
0245	[redacted]	[redacted]	[redacted]											
0245	[redacted]	[redacted]	[redacted]											
0245	[redacted]	[redacted]	[redacted]											
0245	[redacted]	[redacted]	[redacted]											
Total				-188,219.51	-172,805.01	-200,677.24	-182,431.53	-181,982.99	-203,259.33	-198,427.03	-193,101.61	-184,874.49	-178,379.74	-180,857.27
Grand Total														

200301	200302	200303	200304	200305	200306	200307	200308	200309	200310	200311	200312	200401	200402	200403	200404	200405	200406	200407	200408
-519.60	-218.60	-208.80	-254.4	-249.6	-322.8	-381.6	-366.4	-336	-246.6	-238.2	-305.4	-237	-253.2	-217.8	-284	-271.8	-355.2		-729
-451.20	-207.00	-235.80	-163.2	-148.2	-148.2	-165.6	-160.2	-178.8	-131.4	-133.8	-189.6	-202.8	-242.4	-186	-180.6	-156.6	-148.2	-166.8	-190.8
-3,687.60	-7,761.84	-3,431.04		-4996.01	-1099.01	-1248.06	-1349.93	-2182.93	-2814.91	-3076.92	-3594.25	-3863.48	-206.23	-7625.78	-3047.97	-1976.11		-2816.94	-1632.35
-10,186.74	-7,813.27	-4,055.90	-4108.58	-4025.09	-2576.39	-3530.55	-3517.46	-4182.6	-4138.94	-4490.17	-3772.98	-3457.09		-4589.79					
-8,766.34	-7,130.18	-3,545.55	-3093.94	-3337.84	-2559.99	-3665.38	-3507.45	-3856.08	-3717.26	-3582.62	-3802.19	-3295.62	-3900.92	-3486.9	-3896.18	-3255.11			
						-1977.73	-2453.08	-2428.65	-1822.84	-1578.25	-1540.3	-1729.9	-1529.29	-1440.99	-1542.69	-1510.83	-1721.36	-2167.6	-2219.86
-6,842.04	-3,277.71	-3,696.64	-3526.11	-3538.32	-2977.67	-2565.01	-3096.34	-3368.04	-4117.77	-3913.53	-3425.21	-3378.94	-3344.54	-3774.36	-3561.61	-3549.87	-2882.51	-2420.77	-2773.3
-8,164.98	-4,529.41	-4,226.20	-4705.21	-4237.38	-3947.67	-4929.55	-4527.46	-5612.14	-4711.52	-4569.13	-4342.54	-4002.22	-4558.87	-4719.93	-4556.59	-4261.83	-4505.66	-4678	-4305.58
-2,772.00		-2,458.40	-1198.4	-1220.8	-926.8	-1136.8	-1162		-2632	-1402.8	-1187.2		-2147.6	-1181.6		-2500.4		-887.6	
-1,848.00		-1,775.20	-991.2	-1142.4	-1265.6	-1573.6	-1428	-1368.8	-924	-907.2	-996.6	-935.2	-896		-873.6	-1125.6	-1131.2	-1338.4	-1388.8
-1,759.98	-643.69	-646.41	-573.08	-537.77	-621.96	-597.52	-733.32	-683.14	-688.8	-602	-683.2	-616	-610.4	-627.2	-616	-655.2	-618.8		
						-85.2	-90	-175.2	-249.6	-284.4	-245.4	-225.6	-255	-258	-254.4	-238.2	-93.6	-95.4	-84
-2,524.11	-5,926.62	-2,662.02		-4685.14	-10.03		-3097.4	-4248.66	-2498.03	-2815.88		-5285.11	-3338.8	8.09495E-13	-5693.27	-2174.35	-1653.45		-1727.02
-3,284.40		-2,416.40	-1078	-1159.2	-1149.47	-1215.34	-1290.66	-1472.16	-1200.75	-1131.04	-1247.77	-1023.39	-1203.93	-1187.61	-1057.66	-1222.47	-1032.4		
-15,361.52	-7,817.31	-7,340.30	-7318.27	-8101.78	-8572.98	-10051.27	-11044.23	-10369.05	-8475.09	-8029.48	-8622.66	-8547.98	-7782.47	-7869.15	-8502.05	-8124.18	-8354	-10869.42	-10378.54
																	-539	-527.6	
-2,754.82	-1,377.41	-1,505.90	-1484.38	-1450.55	-1314.74	-1092.04	-1454.09	-1452.17	-1588.72	-1420.04	-1427.72	-1459.4	-1370.35	-1493.36	-1571.29	-1442.61	-1167.5		
-3,345.98	-1,848.11	-1,720.10	-1683.41	-1716.31	-1932.48	-2080.4	-2298	-2140.08	-1778.54	-1603.75	-1737.52	-1759.91	-1874.29	-1713.92	-1898.98	-1713.28	-1881.12	-2156.87	-2103.85
-7,718.62	-3,606.12	-4,032.00	-4065.77	-4198.4	-3365.93	-2633.41	-3777.11	-4037.14	-5038.42	-4568.19	-4111.1	-4018.5	-3510.98	-4315.24	-3995	-4333.66	-3762.9	-3490.19	-4041.27
							-1725.53	-1904.48	-1888.08	-717.27	-1856.4	-2031.75	9921.51	-13701.67	-1988.6	-1927.46	-1853.09	-1851.69	-1959.95
										-5588.69	-4478.2	-4381.77	-5945.6	-5860.53	-6968.63	-5956.8	-6259.61	-6984.64	-5662.4
									-117.6	-123.2	-112	-112	-142.8	-109.2	-123.2	-112	-112	-131.6	-120.4
							-403.54	-513.58	-940.43	-1113.54	-1157.71	-1074.34	-1255.24	-1294.58	-1444.03	-1411.22	-1319.3	-1555.17	-1070.55
														-3099.95	-2840.94	-2557.87	-2306.14	-2172.4	-2390.13
-468,619.17	-266,095.49	-218,642.01	-195,210.84	-232,099.90	-194,647.43	-187,324.08	-222,816.51	-220,019.12	-208,245.01	-206,048.93	-213,459.88	-211,118.80	-201,819.35	-252,146.94	-221,436.22	-176,606.13	-181,029.20	-282,709.57	-231,007.23

200409	200410	200411	200412	200501	200502	200503	200504	200505	200506	200507	200508	200509	200510	200511	200512	200601	200602	200603	200604
-294.6	-250.2	-220.2	-266.8	-248.6	-232.6	-209.4	-243	-227.4	-348	-374.4	-310.8	-285.6	-257.4	-232.2	-310.2	-290.4	-212.4	-221.4	-259.8
-192	-145.2	-148.2	-180.6	-255	-237	-237.6	-198	-166.2	-145.2	-211.2	-178.2	-187.8	-162	-151.6	-187.8	-244.8	-191.4	-196.2	-168.6
-2276.26	-2584.73	-3002.04	-3530.56	-3548.76	-3938.75	-3766.19	-2713.58	-1931.32	-1141.76	-1432.46	-1645.91	-2233.54	-2271.51	-2939.56	-3790.9	-3160	-3910.65	-3656.49	-2839.12
									-3073.74	-3859.1	-3540.01	-4641.55	-4201.52	-4319.34	-4180.23		-7669.53	-4289.3	-4056.12
																-3640.67	-4121.46	-3868.79	-3711.95
-2387.83	-1819.06	-1471.12	-1602.71	-1513.8	-1594.72	-1709.43	-1672.12	-1673.62	-1740.06	-3151.18	-3369.7	-3451.07	-2763.83	-2183.42	-2258.94	-2015.38	-2162.05	-1885.46	-1909.32
-3248.29	-3902.59	-4069.16	-3550.2	-3380.67	-3441.1	-3750.06	-3561.7	-3654.85	-2748.03	-2547.64	-3184.05	-3717.7	-4207.92	-4032.66	-3595.82	-3442.32	-3616.28	-3779.22	-3846.35
-5524.89	-4812.37	-4552.76	-4852.55	-3802.22	-4371.98	-5137.27	-4315.83	-4354.45	-4776.94	-5393.13	-5428.59	-5331.59	-5011.72	-4859.71	-4935.58	-4203.45	-4685.17	-4642.86	-4603.93
					-820.8		-1731.2		-1876.8	-999.2	-1064.6	-1000.8	-869.6	-940		-886.4	-875.2	-1768.4	
											-1096.37	-1235.17	-1450.99	-1267.03	-2416.71		-1243.82	-1282.75	-1216.5
-1517.6	-1192.8	-912.8	-912.8	-840	-1612.8		-1820		-1103.2	-1276.8	-1478.4	-1388.4	-1198.4	-924	-1008	-1747.2		-645.6	-1013.6
										-722.4	-862.4	-814.8	-756	-702.8	-730.8	-660.8	-658	-691.6	-694.4
-195.6	-247.8		-524.4	-189.6	-240	-258.6	-244.8	-245.4	-85.8	-93.6	-84.6	-206.4	-248.4	-285.2	-290.4	-177.6	-210.6	-251.4	-234
					-16.48	-16.56	-14.72	-14.32	-20.24	-27.68	-28.32	-22.16	-20.16	-18	-21.92	-17.68	-19.28	-19.28	-17.12
-1610.44	-5105.04	-2788.57	-2825.07		-2356.43	-2997.13	-2871.7	-2940.01		-5933.19	-6205.54	-3711.37	-4174.04	-4279.26	-4598.92	-3529.74		-8693.27	-4353.82
					-847.76	-719.92	-660.55	-541.73	-580.2	-699.1	-624.37	-667.76	-651.36	-711.86	-793.16	-610.17	-650.51	-723.38	-665.83
										-1469.01	-1526.85	-1541.94	-1440.67	-1332.57	-1370.65	-1244.13	-1247.87	-1274.96	-1258.89
					-0.89	-1.02	-0.74	-0.54	-0.38	-0.43	-0.38	-0.38	-0.56	-0.59	-0.6	-0.39		-1.16	-0.6
-10253.22	-8791.59	-8733.32	-8283.58	-8878.28	-7800.64	-7743.89	-8502.44	-8857.55	-9140.27	-12389.29	-12007.11	-11324.38	-9736.73	-7974.21	-8317.46	-8680.78	-7842.81	-7763.72	-8648.43
-1467.2	-522.2	-581	-551.6	-532	-603.4	-550.2	-611.8	-543.2	-592.2	-754.8	-651	-646.2	-623	-553	-607.6	-599.2	-592.2	-674.8	
										-480.2	-501.2	-513.1	-509.6	-519.4	-564.5	-478.1	-513.1	-506.8	-490
												-1396.22	-1513.56	-1438.53	-1643.18	-1427.74	-1384.38	-1458.69	-1546.9
-2151.8	-2061.31	-1767.05	-1825.91	-1798.89	-1726.47	-1698.63	-1793.77	-1728.98	-1651.1	-2140.56	-2133.15	-2117.29	-1931.81	-1649.11	-1786.09	-1853.7	-1709.8	-1816.28	-1926.86
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-1808.71	-1669.65	-1838.73	-1642.47	-200.34															
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-151.2	-123.2	-140	-151.2	-126	-156.8	-170.8	-154	-142.8	-170.8	-137.2	-109.2	-142.8	-128.8	-109.2	-145.6	-142.8	-154	-154	-156.8
-1227.82	-1421.77	-1459.47	-1323.49	-1199.82	-1400.31	-1356.17	-1533.13	-1428.4	-1457.13	-1631.9	-1413.32	-1365.31	-1581.55	-1688.47	-1631.36	-1382.86	-1703.44	-1679.18	-1842.93
-2375.32	-2907.8	-2627.86	-2696.35	-2938.19	-3217.33	-3033.88	-3099.73	-2797.57	-2440.33	-2562.11	-2701.6	-2623.96	-2969.94	-2939.51	-2840.44	-2942.39	-2812.81	-2985.42	-2904.89
			-2.33	-2.38	-2.35	-2.4	-2.2	-2.09	-2.27	-2.46	-2.53	-1.99	-1.9	-1.94	-2.52	-2.32	-2.46	-2.32	-2.28
			-2.99	-3.46	-3.21	-3.29	-3.2	-2.49	-2.74	-4.35	-4.06	-2.91	-2.56	-2.04	-2.77	-2.69	-2.86	-2.68	-2.61
		-21.12	-16.32	-20.16	-23.76	-23.92	-17.92	-15.04	-11.12	-15.04	-11.76	-17.2	-12.48	-15.76	-16.4	-13.76	-17.28	0	-39.36
			-4.9	-6.41	-9.38	-8.76	-8	-7.66	-6.16	-4.97	-3.65	-7.05	-4.5	-0.82	-7.04	-3.08	-2.12	-8.64	-3.28
			-2.15	-1.88	-1.86	-1.73	-1.83	-1.41	-1.4	-3.38	-3.34	-3.18	-2	-2.63	-2.23	-2.37	-2.32	-2.37	-2.22
		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
										-690.55	-614.8	-530.12	-482.58	-453.52		-1134.46	-529.18	-552.19	-558.06
	-857.65	-864.97	-1050.01	-998.82	-939.35	-1067.57	-999.35	-981.53	-1125.29	-914.25	-946.45	-846.27	-838.42	-967.16	-849.74	-965.55	-977.91	-1028.77	-927.84
-2786.11		-1111.98	-2116.19		-1090.56	-2266.33	-949.61	-956.5		-6140	-3994.96		-2729.25	-1134.02	-2307.42		-1006.63	-2729.45	
											-114	-108	-93.6	-84	-85.2	-76.8	-87.6	-92.4	-81.6
							-1107.92	-1097.37	-1163.99	-1383.3	-1389.78	-1424.16	-1319.5	-1175.39	-1072.25	-1083.94	-1088.23	-1005.69	-1163.27
														-173.4	-163.2	-169.8	-136.8	-154.8	-170.4
	-451.1	-492.91	-504.17	-647.67	-578.69	-599.36	-484.54	-503.97	-534.23	-691.47	-608.36	-600.87	-583.59	-524.73	-565.09	-538.45	-579.22	-660.86	-676.01
	-25955.76	-22970.57	-23558.51	-24382.31	-23666.38	-22161.23	-24272.62	-22727.57	-22689.52	-29619.13	-27985.41	-31677.26	-25316.57	-23115.27	-25593.25	-24062.59	-22786.71	-25138.8	-24560.19
										-432		-757.44	-345.6	-455.04		-956.16	-486.72	-489.6	-385.92
											-403.2	-381.6	-326.4	-285.6	-304.8	-595.2		-309.6	-297.6
-21627.02	-20472.88	-21555.28	-25674.84		-46986.97	-25169.05	-21814.01	-21126.97	-23638.8	-21921.95	-23349.89	-20791.16	-20213.53	-23044.21	-23028.15		-22670.56	-46971.49	-20986.04
-2542.26	-2161.85	-2297.62	-3069.34	-3073.36	-2853.94	-3044.82	-2323.8	-2227.14	-2694.47	-2534.38	-2576.31	-2303.79		-4701.16	-2728.14	-2670.58	-2831.59	-2799.71	-2332.92
-254,507.68	-259,741.13	-253,060.25	-269,221.35	-248,682.26	-292,335.75	-266,806.98	-258,216.02	-235,676.91	-244,287.03	-284,665.44	-280,871.54	-284,674.11	-257,292.70	-256,651.87	-269,011.11	-247,506.04	-257,657.63	-291,055.40	-282,039.32

Exhibit ____ (JJB/LAK-2)
Page 8 of 19

200605
-256.2
-159.6
-1754.1
-3429.65
-3475.8
-1891.8
-3721.3
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-1877.6
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-283.2
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-2276.8
-238,576.38
-12,156,234.38

Exhibit ___ (JJB/LAK-2)
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nationalgrid

Carlos A. Gavilondo
General Counsel, New York Distribution

June 29, 2006

VIA OVERNIGHT DELIVERY

Mr. Steven R. Blow, Esq.
Records Access Officer
New York State Department of Public Service
Three Empire State Plaza
Albany, New York 12223

Re: Request for Trade Secret Protection –
Case 01-M-0075, Second CTC Reset Compliance Filing,
Niagara Mohawk Power Corporation
Response to IR No. NMPC-372, PSC-313, (RAV-106)
Second Corrected Response

Dear Mr. Blow:

Pursuant to 16 NYCRR § 6-1 et seq. and Sections 87 and 89 of the Public Officers Law, Niagara Mohawk Power Corporation, d/b/a National Grid ("National Grid" or "Company") hereby submits this request for confidential treatment of certain information provided in connection with the Company's second corrected response to the above-referenced Information Request ("IR"). In order to respond to the subject IR, the Company must provide certain customer-specific information, the public disclosure or which would be inappropriate. Accordingly, National Grid requests the Department of Public Service ("Department") deem these materials as confidential information, and take the necessary steps to safeguard against their disclosure as set forth in 16 NYCRR § 6-1.3.

The basis for the second corrected response is set forth response itself. Inasmuch as the second corrected response includes information the Company deems is entitled to confidential treatment, the Company is submitting this further request for protection. The basis for the Company's request for confidential treatment is set forth below.

The IR in question seeks information relating to, *inter alia*, individual customer identity and the related customer service backout credits ("CSBC") provided to the customers. For purposes of this request, the Company refers to the customer identity and account information in the response as the "Confidential Information." National Grid believes that the Confidential Information being provided herewith qualifies for exemption from public disclosure as set forth in the Freedom of Information Law ("FOIL") and as provided in the Commission's regulations, and requests that the Confidential Information be treated as trade secret or confidential commercial information and protected from disclosure. N.Y. Pub. Off. Law § 87; 16 N.Y.C.R.R. § 6-1.3.

Trade secret and confidential protection is warranted "if disclos[ure] would cause substantial injury to the competitive position of the subject enterprise." N.Y. Pub. Off. Law § 87(2)(d) (Supp. 2005); *see also* 16 N.Y.C.R.R. § 6-1.3. In determining whether information should be considered for confidential treatment, the Commission's regulations set forth six non-exclusive factors:

1. the extent to which disclosure would cause unfair economic or competitive damage;
2. the extent to which the information is known by others;
3. the value of the information to the possessor of the data and its competitors;
4. the difficulty and cost of developing the information;
5. the difficulty in recreating the data without permission; and
6. whether the data is otherwise exempted by law from disclosure.

16 NYCRR § 6-1.3(b)(2).

The Confidential Information is not available to the public at large and the other parties to the above referenced proceeding are not being given access to the Confidential Information. The Confidential Information, combined with the information provided about the customers' respective CSBCs, could be used to calculate the energy usage of individual customers. This information could be used by a customer's competitors so as to determine the customer's energy usage. This information could also be used by energy service companies or other marketing entities that would otherwise not have access to this information without the consent/permission of the customers. Typically, this type of customer-specific information is not publicly released by the Company absent customer authorization to do so, and the Company takes steps to protect such customer-specific information and treat it confidentially.

The non-exclusive factors listed in 16 NYCRR § 6-1.3 (b)(2) militate in favor of granting confidential treatment and protecting the information public disclosure. Accordingly, the Company respectfully requests that confidential and/or trade secret status be granted to the Confidential Information.

For your information, unredacted versions of the Confidential Information will be provided directly to Robert Visalli, Denise Gerbsch, and Patrick Piscitelli of the Department of Public Service Staff at their Syracuse offices. Because of the large volume of information included, the Confidential Information is being provided on compact disk. Mr. Visalli, Ms. Gerbsch and Mr. Piscitelli will be advised to protect the Confidential Information from disclosure pursuant to Section 6-1.3(d) of the regulations. 16 NYCRR § 6-1.3(d). The Company will advise Mr. Visalli, Ms. Gerbsch and Mr. Piscitelli that it is seeking trade secret/confidential treatment for the Confidential Information provided to them and that they should expect further direction from you in that regard. The Company has spoken to counsel's office at the Department and confirmed that this process was acceptable and would not harm the Company's request for trade secret/confidential treatment.

Kindly acknowledge receipt and filing of this request by date-stamping the enclosed copy of this letter and returning it in the postage-paid envelope provided for your convenience.

Respectfully submitted,

Carlos A. Gavilondo

Enc.

Date of Request_6/19/06__ Request No. __PSC-313 Visalli (RAV-106)_CORRECTION NO. 2

NMPC Req. No. _372_

NIAGARA MOHAWK POWER CORPORATION
Case 01-M-0075 – Second CTC Reset Compliance Filing
Request for Information

FROM: PSC-313 Visalli (RAV-106)___

Request:

Please provide the amount of customer service backout credits (CSBCs) given to Direct Customers other than Station Service Customers from 2/1/02 – 5/30/06[1]. The CSBC amounts should be provided by customer by month.

Second Corrected Response:

Please see the attached spreadsheet. The original data that was provided on June 27 has been corrected to reflect the following:

- Farm and Food Processor Pilot Customers (CONS Type AF) and Empire Zone Rider Customers (EZRs) (CONS Type I6) were improperly omitted in the original data but are listed in the attached file.
- In the original data, one or more of the CONS types for some bills may have been computed by the system but not actually billed. An example of this occurs when a bill is computed but not billed before applying taxes, then recomputed again and billed after applying taxes are added. Including the computed but unbilled amounts constitutes a double count. The revised data includes only billed CSBC amounts.
- A station service account was improperly included in the original data, and is omitted on the attached spreadsheet.
- The internal data sources for this extract were the Revenue Warehouse for the period January 2003 through May 2006 and CSS for February 2002 through December 2002. Due to the different ways that the revenue month is defined in the two systems, a number of accounts were double counted in January 2003, the transition month. The new data eliminates for the double counts.

The attached spreadsheet shows an amount of CSBC for Direct Customers of $11,851,239, a reduction of $356,402 from the original response.

Name of Respondent: Mark Siegel & David Feiler Date of Reply: 6/29/06

[1] CSBCs for Station Service Customers are already being provided in response to IR RAV-34.

Form 103

ESCO_ID_CD	ESCO NAME	KY_BA	Name	200202	200203	200204	200205	200206	200207	200208	200209	200210
[redacted]												
Total				-188,219.51	-172,605.01	-200,677.24	-182,431.53	-161,982.99	-203,259.33	-196,427.03	-193,101.61	-184,874.49
Grand Total												

ESCO ID CD	ESCO NAME	KY-SA	Name	200211	200212	200301	200302	200303	200304	200305	200306	200307
[redacted]												
Total				-178,379.74	-179,204.30	-230,390.68	-254,050.44	-202,990.15	-194,988.09	-231,925.65	-194,439.58	-197,069.43
Grand Total												

Exhibit ___(JJB/LAK-2)
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ESCO_ID_CD	ESCO NAME	KY_BA	Name	200308	200309	200310	200311	200312	200401	200402	200403	200404
[redacted]	[redacted]	[redacted]	[redacted]									
Total				-212,671.24	-219,748.27	-206,073.16	-207,863.28	-213,203.43	-210,894.55	-201,425.30	-251,907.89	-221,241.67
Grand Total												

ESCO ID CD	ESCO NAME	KY BA	Name	200405	200406	200407	200408	200409	200410	200411	200412	200501
[redacted]	[redacted]	[redacted]	[redacted]									
[redacted]	[redacted]	[redacted]	[redacted]									
[redacted]	[redacted]	[redacted]	[redacted]					-21,627.02	-20,472.88	-21,555.28	-25,674.84	
[redacted]	[redacted]	[redacted]	[redacted]					-2,542.26	-2,161.85	-2,297.82	-3,069.34	-3,073.36
Total				-176,406.68	-180,804.55	-262,468.72	-230,783.78	-254,194.23	-259,567.48	-252,874.00	-268,972.10	-248,477.41
Grand Total												

ESCO_ID_CD	ESCO NAME	KY_BA	Name	200502	200503	200504	200505	200506	200507	200508	200509	200510
[redacted]	[redacted]	[redacted]	[redacted]						-432.00		-757.44	-345.60
[redacted]	[redacted]	[redacted]	[redacted]							-403.20	-381.60	-326.40
[redacted]	[redacted]	[redacted]	[redacted]	-46,986.97	-25,169.05	-21,814.01	-21,126.97	-23,638.80	-21,921.95	-23,349.89	-20,791.16	-20,213.53
[redacted]	[redacted]	[redacted]	[redacted]	-2,863.94	-3,044.82	-2,323.80	-2,227.14	-2,694.47	-2,534.38	-2,576.31	-2,303.79	
Total				-292,091.30	-266,615.33	-258,010.57	-235,493.66	-244,025.58	-284,368.59	-280,569.49	-284,435.06	-257,106.45
Grand Total												

ESCO_ID_CD	ESCO NAME	KY_BA	Name	200511	200512	200601	200602	200603	200604	200605
[redacted]				-455.04		-956.16	-486.72	-489.60	-385.92	
[redacted]				-285.60	-304.80	-595.20		-309.60	-297.60	-283.20
[redacted]				-23,044.21	-23,028.15		-22,870.56	-46,971.49	-20,986.04	-20,745.91
[redacted]				-4,701.16	-2,728.14	-2,670.58	-2,831.59	-2,799.71	-2,332.92	-2,278.60
Total				**-256,485.42**	**-268,772.66**	**-247,322.19**	**-257,657.63**	**-291,056.40**	**-262,039.32**	**-238,676.38**
Grand Total										**-11,861,239.47**

Exhibits of Michael J. Kelleher, Steven W. Tasker and James J. Fletcher

Exhibit___(GSC-11)

Schedule 1

Niagara Mohawk Power Corporation
Regulatory Deferrals
Comparison of Staff's and Company's Positions
Deferral Balance as of December 31, 2007

	12/30/2007 Forecast Balance Per Staff	Company	Difference
Regulatory Assets			
Storm Restoration Costs	$ 19,581,516	$ 24,983,433	$ (5,401,917)
Pension Settlement Loss	20,976,835	20,976,835	-
Customer Service Backout Credits	10,309,579	10,309,579	-
NYPA Transmission Access (NTAC)	13,050,967	13,050,967	-
NYISO Schedule 1 Costs	78,946,665	86,732,477	(7,785,812)
NYISO Schedule 2 Costs	13,280,454	13,280,454	-
Generation Sale Incentive	18,556,040	18,556,040	-
Customer Service Backout Credits	95,308,614	105,448,250	(10,139,636)
Pension Expense Deferred	152,898,379	155,998,980	(3,100,601)
OPEB Expense Deferred	186,468,090	175,866,148	10,601,942
Religious Rates Revenue Deferred	2,681,215	2,681,215	-
City of Buffalo Settlement Agreement	684,320	684,320	-
Customer Outreach & Education Program	-	-	-
SC7 Standby Service Lost Revenues	868,092	15,748,676	(14,880,584)
SC-7 Standby Lost Revenue Offset	(8,666,667)	(8,666,667)	-
SIR Program Costs	80,372,320	80,372,320	-
Generation Stranded Costs Adjustments	18,084,454	62,827,412	(44,742,958)
Stray Voltage	7,390,909	14,781,817	(7,390,909)
Incentive Return on Retirement Funding	50,247,956	50,247,956	-
Disputed Station Service Lost Revenues	-	72,448,394	(72,448,394)
Over-recovered CTC's 2006-07	(5,250,325)	-	(5,250,325)
Under-recovered Deferral Surcharges 2006-07	2,900,137	-	2,900,137
Pension & OPEB Cost Increase Offsets	(36,580,500)	-	(36,580,500)
Subtotal - Regulatory Assets	**$ 722,109,050**	**$ 916,328,606**	**$ (194,219,556)**
Regulatory Liabilities			
NYPA MOU	$ (16,676,906)	$ (16,676,906)	$ -
Electric Customer Service Penalties	(13,649,300)	(11,953,000)	(1,696,300)
Loss on Sale of Buildings	(1,825,072)	(1,888,320)	63,249
Petroleum Tax Audit Refund	(5,752,659)	(5,752,659)	-
Affiliate Rule Employee Transfer Credits	(166,725)	(166,725)	-
Pension/OPEB Curtailment/Settlement Gains	(23,552,091)	(23,552,091)	-
Delay in Merger Rate Plan Start Date	(12,555,000)	(12,555,000)	-
Currently Provided Incidental Services	(399,255)	(399,255)	-
NYS Sales Tax Refund (1992-1998)	(1,477,332)	(1,477,332)	-
Economic Development Fund	(5,424,195)	(7,575,609)	2,151,414
Meter Read Connect/Disconnect Service Charge	(158,753)	(158,753)	-
Low Income Discount Program	3,000,000	3,000,000	-
Tax and Accounting Changes	(21,356,984)	(21,356,984)	-
Medicare Act of 2003	(26,201,771)	(26,201,771)	-
NYS GRT Tax Refund (1991-1994)	(3,300,422)	(3,300,422)	-
IRS Income Tax Refund (1989-1990)	(48,100)	(48,100)	-
Service Re-establishment Charges	(464,158)	(464,158)	-
Carrying Charges on Non-pension/OPEB deferrals	(1,153,634)	(1,681,708)	528,074
Subtotal - Regulatory Liabilities	**$ (131,162,357)**	**$ (132,208,793)**	**$ 1,046,437**
PowerChoice Appendix E Netting	**$ (79,599,407)**	**$ (79,599,407)**	**$ -**
MRA Interest Savings Deferred	**$ (92,534,022)**	**$ (92,534,022)**	**$ -**
Total - Net Regulatory Assets/Liabilities	**$ 418,813,265**	**$ 611,986,384**	**$ (193,173,119)**

Niagara Mohawk Power Corporation
Regulatory Deferrals
Comparison of Staff's and Company's Adjustments
Deferral Balance as of December 31, 2007

		Staff's Adjustments		Company's Adjustments		Difference
Adjustments in which Staff and Company do not agree:						
Regulatory Assets						
1. Storm Restoration Costs						
a. To eliminate the estimated portion of storm #55645 restoration costs that occurred on 1/31/02, which is prior to the Merger Rate Plan's 2/1/02 Effective Date and therefore not deferrable	$	(5,305,307)	$	-	$	(5,305,307)
b. To eliminate storm costs deferred for "transportation - pooled vehicles		(257,307)		(322,188)		64,881
c. To eliminate overtime expenses incurred long after the storm was over; such overtime was not authorized and the restoration might have been accomplished on regular time for which an allowance is already provided in base rates:						
(2) storm #82950 (not agreed to by Company; IR RAV-43; #267)		(49,117)		-		(49,117)
(1) storm #55645 (not agreed to by Company; IR RAV-44; #268)		(32,311)		-		(32,311)
d. To eliminate invoices for tree removal work undertaken during 12/13/03 - 3/27/04 related to storm #82978 which occurred on 11/13/03. Such tree removal work is not storm restoration, but is preventative (IR RAV-55; #285)		(80,063)		-		(80,063)
Total Storm Restoration Cost Adjustments		(5,724,105)		(322,188)		(5,401,917)
2. NYISO Schedule 1 Costs						
a. To disallow NYISO Schedule 1 deferrals booked subsequent to December 31, 2001 that relate to pre-January 1, 2002 reconciliations		(8,325,060)				(8,325,060)
b. To reflect the portion of the NYISO Schedule I errors that relate to post-December 31, 2001 periods per IR RAV-35 (#259)		(79,281)		(589,875)		510,594
c. Regulatory Deferral IR #12 - NYISO Sched. 1 refunds		-		(28,654)		28,654
Total NYISO Schedule 1 Cost Adjustments		(8,404,341)		(618,529)		(7,785,812)
3. Customer Service Backout Credits (CSBCs) post 9/01						
a. To eliminate CSBCs given to station service customers; such customers were given CSBCs by the Company because the Company considered them to be direct customers; Rule 39 does not provide for giving CSBCs to direct customers. Also, these customers did not meet the eligibility requirements set forth in Rule 39 (tariff 71) even if Rule 39 did allow CSBCs for direct customers. Finally, since there are no lost revenues for station service customers (refer to adjustment 20 below), the Company has not lost any revenues from a ratemaking perspective for giving these customers CSBCs; therefore such CSBCs are not deferrable.		(1,616,214)		-		(1,616,214)
b.1 To eliminate CSBCs given to direct customers (other than station service customers); such customers do not qualify for CSBCs per the eligibility requirements set forth in Rule 39		(11,364,563)		-		(11,364,563)
b.2 To correct adjustment b.1 to eliminate the avoidable portion of the CSBC as agreed to in response to IR NMPC-5.		2,841,142		-		2,841,142
Total Customer Service Backout Credit Adjustments		(10,139,635)		-		(10,139,635)
4. Pension Expense Deferred						
a. To properly reflect percentage of pensions capitalized using the capitalized labor percentage		(7,036,925)		(7,671,851)		634,926
b.1 To reflect incremental third party billing and intercompany billing revenues for pension costs received by the Company but not credited to the pension deferral account (pre-ERP)		(468,066)		(380,359)		(87,707)
b.2 To modify adjustment b.1 to eliminate the third party billing portion of the adjustment and to add in 100% of pre-ERP intercompany billing revenues		(13,153)		-		(13,153)
c.1 To reverse non-incremental third party billing revenues erroneously credited to the pension deferral account		109,158		-		109,158
c.2 To modify adjustment c.1 to eliminate incremental third party billing revenues post-ERP		346,971		-		346,971
d.1 To eliminate double-count related to employees transferred from Niagara Mohawk to Service Company		(514,905)		-		(514,905)
d.2 To reflect Staff's revised calculation as set forth in our responsive testimony		236,067		-		236,067

Niagara Mohawk Power Corporation
Regulatory Deferrals
Comparison of Staff's and Company's Adjustments
Deferral Balance as of December 31, 2007

	Staff's Adjustments	Company's Adjustments	Difference
e. To reflect updated actuarial computations as set forth in Staff's responsive testimony	58,922	-	58,922
f. To reflect adjustment of pension fair value from generation stranded cost	-	3,870,880	(3,870,880)
Total Pension Expense Deferred Adjustments	(7,281,931)	(4,181,330)	(3,100,601)
5. OPEB Expense Deferred			
a.1 To properly reflect percentage of OPEBs capitalized using the capitalized labor percentage	(12,646,075)	(22,447,015)	9,800,940
a.2 To modify adjustment a.1 per Staff's responsive testimony	650,523	-	650,523
b.1 To reflect incremental third party billing and intercompany billing revenues for OPEBs costs received by the Company but not credited to the OPEBs deferral account (pre-ERP)	(728,229)	(431,254)	(296,975)
b.2 To modify adjustment b.1 to eliminate the third party billing portion of the adjustment and to add in 100% of pre-ERP intercompany billing revenues	192,516	-	192,516
c.1 To reverse non-incremental third party billing revenues erroneously credited to the OPEBs deferral account	(22,175)	-	(22,175)
c.2 To modify adjustment c.1 to eliminate incremental third party billing revenues post-ERP	656,820	-	656,820
d.1 To eliminate double-count related to employees transferred from Niagara Mohawk to Service Company	(295,862)	-	(295,862)
d.2 To reflect Staff's revised calculation as set forth in our responsive testimony and workpapers	91,904	-	91,904
e. To reflect updated actuarial computations as set forth in Staff's responsive testimony	(175,749)	-	(175,749)
Total OPEB Expense Deferred Adjustments	(12,276,327)	(22,878,269)	10,601,942
6. SC-7 Standby Service Lost Revenues			
To eliminate the portion of SC-7 standby service revenues related to station service customers for the same reasons as set forth in 20.b below	(14,880,584)	-	(14,880,584)
7. Generation Stranded Costs Adjustments			
a.1 To reflect staff's recommendation that the revenues received for providing new services to Constellation be credited to ratepayers (IR RAV-61; #291)	(2,653,982)	(861,811)	(1,792,171)
a.2 To increase adjustment d.1 to reflect proper level of such revenues per the panel testimony of Kelleher, Tasker and Fletcher	(597,787)	-	(597,787)
b.1 To reflect lost decommissioning fund earnings due to the Company's not fully contributing the 2001 rate allowance for decommissioning	(216,014)	(19,422)	(196,592)
b.2 To reduce adjustment e.1 to the level set forth in the panel testimony of Kelleher, Tasker and Fletcher	196,592	-	196,592
c. To reflect the January 2002 nuclear amortization required by the Nine Mile settlement in Case 01-E-0011 until rates were reset in February 2002	(11,200,000)	-	(11,200,000)
d. To allocate to stockholders 100% of the Nine Mile 1 sales price reduction	(7,500,000)	-	(7,500,000)
e.1 To remove the co-tenants' share of the pension fair value adjustment from nuclear stranded costs to be paid by Niagara Mohawk ratepayers	(5,702,226)	-	(5,702,226)
e.2 To temporary withdraw adjustment j.1 until the next CTC Reset, as more time is needed to fully evaluate the issue	5,702,226	-	5,702,226
f. To reflect adjustment of pension fair value to pension deferral	-	(14,761,000)	14,761,000
g. FAS 109	-	38,937,000	(38,937,000)
h. Interest on 1999 Curtailment Gain per Nuclear Compliance IR PSC-10		(523,000)	523,000
Total GenerationStranded Cost Adjustments	(21,971,191)	22,771,767	(44,742,958)
8. Stray Voltage	(7,390,909)	-	(7,390,909)

9. Disputed Station Service Lost Revenues

a. To eliminate 100% of station service lost revenues deferred for the PowerChoice years preceding the Merger Rate Plan. Such revenues were not / could not possibly have been reflected in PowerChoice rates because the generating stations had yet to be sold when PowerChoice rates were set (the PowerChoice forecast was based on the Company's December 1996 sales forecast). As such,

Niagara Mohawk Power Corporation
Regulatory Deferrals
Comparison of Staff's and Company's Adjustments
Deferral Balance as of December 31, 2007

	Staff's Adjustments	Company's Adjustments	Difference	
from a ratemaking perspective, no revenues were lost since they were never reflected in PowerChoice rates. Moreover, the deferrals allowed in the Merger Joint Proposal were prospective only; this deferral constitutes retroactive ratemaking and is not allowable under the terms of the Merger Joint Proposal (IR PSC-26)	(19,416,530)	-	(19,416,530)	
b. To eliminate 100% of station service lost revenues deferred for the Merger Rate Plan period 2/1/02 - 6/30/05. Such revenues were not / could not possibly have been reflected in setting the Merger Rates since the Company's 1/17/01 pre-filed, unadjusted sales forecast supporting the Merger Rates did not include any such sales as admitted to by the Company in the CTC compliance filing dated 7/29/05, Volume 2, Attachment 6, page 39, footnote 9	(53,031,864)	-	(53,031,864)	
	(72,448,394)	-	(72,448,394)	
10. Over-recovered CTC's 2006-07 for Disputed Station Service forecast sales	(5,250,325)	-	(5,250,325)	
11. Under-recovered Deferral Surcharges 2006-07 for Disputed Station Service forecast sales	2,900,137	-	2,900,137	
12. Pension & OPEB Cost Increase Offsets				
a. To reflect offsets for the non-pension & OPEB employee benefit reductions negotiated as part of the October 2004 union contract	(4,650,500)	-	(4,650,500)	
b. To reflect offsets for the operational savings in the approved union contract	(12,755,750)	-	(12,755,750)	
c. To treat increases in pension & OPEB costs given to management employees as "costs to achieve"	(19,174,250)	-	(19,174,250)	
Total Pension & OPEB Deferral Offset Adjustments	(36,580,500)	-	(36,580,500)	
TOTAL REGULATORY ASSET	**$ (199,448,104)**	**$ (5,228,549)**	**$ (194,219,555)**	$(1,046,436)
Regulatory Liabilities				
1. Electric Customer Service Penalties				
a. To reflect penalty incurred by the Company for not meeting the 2003 customer service "percent meters read" target	$ (1,696,300)	$ -	$ (1,696,300)	
2. Loss on Sale of Buildings				
a. To eliminate the remaining portion of the Dey Building deferral related to leasehold improvements; the Company did not petition for deferral accounting in the timeframe required under Section 167.4 of the Uniform System of Accounts and the Company's reliance on the deferral being allowable under the directives provided by the Commission regarding the sale of the Company owned O'Neill and Buffalo Electric Buildings is not applicable to this lease breaking transaction; moreover, deferral would result in a double-recovery as this is a cost to achieve merger savings which have already been fully provided for in the Merger Rate Plan	63,249	-	63,249	
3. Economic Development Fund				
a. Revised forecast 7/2005 through 12/2007	(27,769,426)	(29,920,840)	2,151,414	
4. Carrying Charge on Non-Pension OPEB Deferral	(1,153,634)	(1,681,708)	528,074	
TOTAL REGULATORY LIABILITES	**$ (30,556,112)**	**$ (31,602,548)**	**$ 1,046,437**	
Total - Net Regulatory Assets/Liabilities - Not in Agreement	**$ (230,004,216)**	**$ (36,831,097)**	**$ (193,173,119)**	

Niagara Mohawk Power Corporation
Regulatory Deferrals
Comparison of Staff's and Company's Adjustments
Deferral Balance as of December 31, 2007

	Staff's Adjustments	Company's Adjustments	Difference
Adjustments in which Staff and Company currently agree:			
Assets			
1. Storm Overtime (IR RAV-42; #267)	(4,866)	(4,866)	-
2. NYISO Schedule 1 Costs (IR RAV-35) (#259)	(730,316)	(730,316)	-
3. Customer Outreach and Education	(206,143)	(206,143)	-
4. SIR Program Costs	(1,047,640)	(1,047,640)	-
5. Gen. Stranded Costs - eliminate NYS income tax on nuclear real estate taxes (IR RAV-62, 292)	(1,382,000)	(1,382,000)	-
6. Gen. Stranded Costs - reduce NYS income tax liability (IR RAV-47, #277)	(569,093)	(569,093)	-
7. Gen. Stranded Costs - reflect 6-30-2005 NYSIT liability for non-deductibility of nuclear stranded costs	(9,063,907)	(9,063,907)	-
8. Gen. Stranded Costs - reduce nuclear stranded costs per IR RAV-32.b (#253)	(286,710)	(286,710)	-
9. Gen. Stranded Costs - reduce nuclear stranded costs related to purchase price adjustment	(396,974)	(396,974)	-
10. Gen. Stranded Costs - limit the 2002 NM#1 refueling outage deferral to $12M	(595,000)	(595,000)	-
Total Assets	$ (14,282,649)	$ (14,282,649)	$ -
Liabilities			
1. NYPA MOU - correction of deferral balance (IR RAV-38) (#262)	(237,961)	(237,961)	-
2. Electric Customer Service Penalties (pre-2002 ooked penalty)	(1,530,000)	(1,530,000)	-
3. Loss on Sale of Buildings - Deys Building Furniture	34,570	34,570	-
4. Currently Provided Incidental Services - Energy Check On-Line	(115,366)	(115,366)	-
5. Economic Development Fund (IR RAV-77) (#314)	14,755	14,755	-
6. NYS GRT Tax Refund (1991-1994)	(3,300,422)	(3,300,422)	-
7. IRS Income Tax Refund (1989-1990)	(48,100)	(48,100)	-
8. Service Re-establishment Charges	(464,158)	(464,158)	-
Total Liabilities	$ (5,646,682)	$ (5,646,682)	$ -
Total - Net Regulatory Assets/Liabilities - In Agreement	$ (19,929,331)	$ (19,929,331)	$ -
Total Adjustments	$ (249,933,547)	$ (56,760,428)	$ (193,173,119)
Company's Original (July 29, 2006 Second CTC Reset) Projected Balance	668,746,812	668,746,812	
Less Proposed Adjustments	(249,933,547)	(56,760,428)	$ (193,173,119)
Proposed Balance	$ 418,813,265	$ 611,986,384	$ (193,173,119)

Exhibits of Scott D. Leuthauser

Exhibit__(SDL-3)

National Grid USA
Elevated Voltage Deferral
Direct Labor Charges (removed non-incremental employee charges)

Empl Name	Fiscal Yr	Job Cd	Job Cd Descr	Criteria (from response to Question 4(a)-®) utilized to determine employee labor is incremental	Elevated Voltage Work Performed
[redacted]	2005	97M032	Distribution Inspector C	First line internal employees	URD Inspections - Dist
	2006	97M032	Distribution Inspector C	First line internal employees	
	2005	97D019	Chief Cable Splicer A	First line internal employees	Convential UG - Dist
	2006	97D019	Chief Cable Splicer A	First line internal employees	
	2005	97M028	Distribution Inspector B	First line internal employees	Touch Potential Tests - Dist, URD Inspections - Dist,
	2006	97M028	Distribution Inspector B	First line internal employees	UCD Inspections - Dist, Conventional UG - Dist
	2005	97D019	Chief Cable Splicer A	First line internal employees	Convential UG - Dist
	2006	97D019	Chief Cable Splicer A	First line internal employees	
	2005	97D019	Chief Cable Splicer A	First line internal employees	Convential UG - Dist
	2006	97D019	Chief Cable Splicer A	First line internal employees	
	2005	97J010	Chief Mechanic A	First line internal employees	OH Inspections - Dist
	2006	97J010	Chief Mechanic A	First line internal employees	
	2005	97M068	Line Mechanic-Hot Stick	First line internal employees	Convential UG - Dist
	2006	97M068	Line Mechanic-Hot Stick	First line internal employees	
	2005	97J010	Chief Mechanic A	First line internal employees	Convential UG - Dist
	2006	97J010	Chief Mechanic A	First line internal employees	
	2005	8622	Svr T & D	A manager or supervisor explicitly hired for compliance with the program	Touch Potential Administration
	2006	4652	Construction Coor	A manager or supervisor explicitly hired for compliance with the program	
		8622	Svr T & D	A manager or supervisor explicitly hired for compliance with the program	
	2005	97M032	Distribution Inspector C	First line internal employees	URD Inspections - Dist, UCD Inspections - Dist,
	2006	97M032	Distribution Inspector C	First line internal employees	Convential UG - Dist
	2005	97M028	Distribution Inspector B	First line internal employees	URD Inspections - Dist, Street Light Standard Insp
	2006	97M028	Distribution Inspector B	First line internal employees	
	2005	5640	Operations Planner	A manager or supervisor explicitly hired for compliance with the program	Touch Potential Administration
		8753	Mgr Quality/Gas Contracts	A manager or supervisor explicitly hired for compliance with the program	
	2006	5640	Operations Planner	A manager or supervisor explicitly hired for compliance with the program	
	2005	97D019	Chief Cable Splicer A	First line internal employees	OH Inspections Dist
	2006	97D019	Chief Cable Splicer A	First line internal employees	
	2005	6655	Area Resource Coordinator	A manager or supervisor explicitly hired for compliance with the program	Touch Potential Administration,URD Inspections - Dist,
	2006	8629	Mgr Maint Insp & Assesement	A manager or supervisor explicitly hired for compliance with the program	Street Light Standard Inspec Dis, Convential UF - Dist
	2005	97M036	Laborer	First line internal employees	Conventional UG - Dist
	2006	97D002	Cable Splicer A	First line internal employees	
		97D014	Cable Splicer Helper	First line internal employees	Conventional UG - Dist
		97M036	Laborer	First line internal employees	
	2005	97M032	Distribution Inspector C	First line internal employees	URD Inspections Dist, Convential UG - Dist
	2006	97M032	Distribution Inspector C	First line internal employees	Inspection Administration - Dist
	2005	97C027	Janitor A	First line internal employees	Street Light Standard Inspec Dist,Inspection Admin-Dist
	2006	97M054	Line Mechanic Helper	First line internal employees	
		97M122	Street Light Inspector	First line internal employees	
	2005	97M040	Line Mechanic A	First line internal employees	Conventional UG - Dist
	2006	97D002	Cable Splicer A	First line internal employees	
		97M040	Line Mechanic A	First line internal employees	
	2005	97M049	Line Mechanic C	First line internal employees	OH Inspections Dist
	2006	97M049	Line Mechanic C	First line internal employees	
		97M065	Line Mechanic-Hot Stick	First line internal employees	
		97M066	Line Mechanic-Hot Stick	First line internal employees	
		97M117	One Person Line/Tbl Mechanic	First line internal employees	
	2005	97M032	Distribution Inspector C	First line internal employees	URD Inspections-Dist, Convential UG-Dist
	2006	97M032	Distribution Inspector C	First line internal employees	
	2005	97M028	Distribution Inspector B	First line internal employees	URD Inspections Dist
	2006	97M028	Distribution Inspector B	First line internal employees	
	2005	97D019	Chief Cable Splicer A	First line internal employees	UCD Inspections Dist
	2006	97D019	Chief Cable Splicer A	First line internal employees	
	2005	97M032	Distribution Inspector C	First line internal employees	URD Inspections - Dist, Convential UG - Dist
		97M068	Line Mechanic-Hot Stick	First line internal employees	
	2006	97M032	Distribution Inspector C	First line internal employees	
	2005	977043	Junior Clerk	First line internal employees	Street Light Standard Insp-Dist, Inspection Admin - Dist
	2006	97M122	Street Light Inspector	First line internal employees	
	2005	97M032	Distribution Inspector C	First line internal employees	URD Inspections Dist
	2006	97M032	Distribution Inspector C	First line internal employees	
	2005	97M032	Distribution Inspector C	First line internal employees	URD Inspections Dist
	2006	97M032	Distribution Inspector C	First line internal employees	
	2005	97F108	Service Representative C	First line internal employees	Conventional UG - Dist
	2006	97D002	Cable Splicer A	First line internal employees	
		97D014	Cable Splicer Helper	First line internal employees	Conventional UG - Dist
		97F108	Service Representative C	First line internal employees	
	2005	97J058	Mechanic C	First line internal employees	OH Inspections Dist
	2006	97J058	Mechanic C	First line internal employees	
	2005	97J010	Chief Mechanic A	First line internal employees	Conventional UG - Dist
	2006	97J010	Chief Mechanic A	First line internal employees	
	2005	97M032	Distribution Inspector C	First line internal employees	Touch Potential Tests - Dist, Inspection Admin - Dist,
	2006	97M032	Distribution Inspector C	First line internal employees	
		97R035	Electric Planner A-T	First line internal employees	
	2005	97F103	Service Representative B	First line internal employees	Conventional UG - Dist, Inspection Admin - Dist
	2006	97C048	Janitor D	First line internal employees	
		97D002	Cable Splicer A	First line internal employees	
		97F100	Service Representative A	First line internal employees	
	2005	97D019	Chief Cable Splicer A	First line internal employees	Conventional UG - Dist
	2006	97D019	Chief Cable Splicer A	First line internal employees	
	2005	97M028	Distribution Inspector B	First line internal employees	URD Inspections Dist
	2006	97M028	Distribution Inspector B	First line internal employees	
	2005	97D019	Chief Cable Splicer A	First line internal employees	UCD Inspections - Dist, Conventional UG - Dist
	2006	97D019	Chief Cable Splicer A	First line internal employees	
	2005	97M032	Distribution Inspector C	First line internal employees	Inspection Administration-Dist, Inspection Admin-Trans
	2006	97M032	Distribution Inspector C	First line internal employees	
	2005	97D010	Cable Splicer C	First line internal employees	Conventional UG - Dist
	2006	97D010	Cable Splicer C	First line internal employees	
	2005	97D019	Chief Cable Splicer A	First line internal employees	Conventional UG - Dist
	2006	97D019	Chief Cable Splicer A	First line internal employees	
	2005	3522	Coordinator	A manager or supervisor explicitly hired for compliance with the program	Touch Potential Tests - Dist, Inspection Admin - Dist,
	2006	3522	Coordinator	A manager or supervisor explicitly hired for compliance with the program	Inspection Administration - Trans
		7470	Supervisor	A manager or supervisor explicitly hired for compliance with the program	
	2005	97D010	Cable Splicer C	First line internal employees	Conventional UG - Dist
	2006	97D010	Cable Splicer C	First line internal employees	

National Grid USA
Elevated Voltage Deferral
Direct Labor Charges (removed non-incremental employee charges)

Empl Name	Fiscal Yr	Job Cd	Job Cd Descr	Criteria (from response to Question 4(a)-(f)) utilized to determine employee labor is incremental	Elevated Voltage Work Performed
[redacted]	2005	97M066	Line Mechanic-Hot Stick	First line internal employees	Conventional UG - Dist
	2006	97M066	Line Mechanic-Hot Stick	First line internal employees	
	2005	97F100	Service Representative A	First line internal employees	UCD Inspections - Dist
		97W017	Plant Guard C	First line internal employees	
	2006	97D002	Cable Splicer A	First line internal employees	
		97D014	Cable Splicer Helper	First line internal employees	
		97F100	Service Representative A	First line internal employees	
		97W017	Plant Guard C	First line internal employees	
	2005	97L016	Gas Line Inspector B	First line internal employees	Touch Potential Tests - Dist, URD Inspections - Dist
	2006	97L016	Gas Line Inspector B	First line internal employees	
	2005	97D006	Cable Splicer B	First line internal employees	URD Inspections - Dist, Convential UG - Dist
	2006	97D006	Cable Splicer B	First line internal employees	
		97M028	Distribution Inspector B	First line internal employees	

National Grid USA
Elevated Voltage Deferral
Direct Labor Charges (removed non-incremental employee charges)

Empl Name	Fiscal Yr	Job Cd	Job Cd Descr	Criteria (from response to Question 4(a)-®) utilized to determine employee labor is incremental	Elevated Voltage Work Performed
[redacted]	2005	4292	Sr IT Analyst	Internal work to develop new software systems to comply with the Order	Touch Potential Administration
	2006	4292	Sr IT Analyst	Internal work to develop new software systems to comply with the Order	
	2005	97D002	Cable Splicer A	First line internal employees	UCD Inspections Dist
	2006	97D002	Cable Splicer A	First line internal employees	
		97D006	Cable Splicer B	First line internal employees	
	2005	97D010	Cable Splicer C	First line internal employees	Conventional UG - Dist
	2006	97D010	Cable Splicer C	First line internal employees	
	2005	7222	Svr Const & Maintenance	A manager or supervisor explicitly hired for compliance with the program	Street Light Standard Insp - Dist, Inspection Admin - Dist
		7470	Supervisor	A manager or supervisor explicitly hired for compliance with the program	
	2006	7470	Supervisor	A manager or supervisor explicitly hired for compliance with the program	
	2005	97J006	Chief Maint Mech A	First line internal employees	Conventional UG - Dist
	2006	97J006	Chief Maint Mech A	First line internal employees	
	2005	97F057	Customer Rep C	First line internal employees	Touch Potential Admin, Inspection Admin- Trans
	2006	974117	Office Technician C	First line internal employees	
		97F057	Customer Rep C	First line internal employees	
	2005	97M010	Chief Line Mech A Htstick	First line internal employees	Touch Potential Tests Trans
	2006	97M010	Chief Line Mech A Htstick	First line internal employees	
	2005	97M032	Distribution Inspector C	First line internal employees	Touch Potential Admin, Inspection Admin- Dist
	2006	7470	Supervisor	A manager or supervisor explicitly hired for compliance with the program	Touch Potential Tests Trans
		97M032	Distribution Inspector C	First line internal employees	
	2005	97G026	Laboratory Tech B (Elec)	First line internal employees	Touch Potential Tests Dist
	2006	97G026	Laboratory Tech B (Elec)	First line internal employees	
	2005	97G022	Laboratory Tech A (Elec)	First line internal employees	Touch Potential Tests Dist
	2006	97G022	Laboratory Tech A (Elec)	First line internal employees	
	2005	97D006	Cable Splicer B	First line internal employees	UCD Inspections- Dist, Convential UG-Dist
	2006	97D006	Cable Splicer B	First line internal employees	
	2006	97M122	Street Light Inspector	First line internal employees	Street Light Standard Insp - Dist, Inspection Admin - Dist
	2005	1400	Administrative Assistant		Inspection Administration - Dist
	2006	1400	Administrative Assistant		
	2005	97M028	Distribution Inspector B	First line internal employees	Touch Potential Tests Dist
	2006	97M028	Distribution Inspector B	First line internal employees	
	2005	8657	IT Team Leader	Internal work to develop new software systems to comply with the Order	Touch Potential Administration
	2006	8657	IT Team Leader	Internal work to develop new software systems to comply with the Order	
	2005	97D010	Cable Splicer C	First line internal employees	Inspection Administration - Dist
	2006	97D010	Cable Splicer C	First line internal employees	
		97D018	Chief Cable Splicer A	First line internal employees	
		97D019	Chief Cable Splicer A	First line internal employees	
	2005	97M010	Chief Line Mech A Htstick	First line internal employees	Touch Potential Tests Trans
	2006	97M010	Chief Line Mech A Htstick	First line internal employees	
	2005	97D010	Cable Splicer C	First line internal employees	Conventional UG - Dist
	2006	97D010	Cable Splicer C	First line internal employees	
	2005	97M028	Distribution Inspector B	First line internal employees	Conventional UG - Dist
	2006	97D014	Cable Splicer Helper	First line internal employees	
		97M028	Distribution Inspector B	First line internal employees	
	2005	97D010	Cable Splicer C	First line internal employees	Conventional UG - Dist, Inspection Admin - Dist
	2006	97D010	Cable Splicer C	First line internal employees	
		97D019	Chief Cable Splicer A	First line internal employees	
	2005	7222	Svr Const & Maintenance	A manager or supervisor explicitly hired for compliance with the program	URD Inspections -Dist, Street Light Standard Insp- Dist
		7470	Supervisor	A manager or supervisor explicitly hired for compliance with the program	Convential UG - Dist, Inspection Admin - Dist
	2006	7470	Supervisor	A manager or supervisor explicitly hired for compliance with the program	Inspection Admin - Trans

National Grid USA
Elevated Voltage Deferral
Direct Labor Charges (removed non-incremental employee charges)

Empl Name	Fiscal Yr	Job Cd	Job Cd Descr	Criteria (from response to Question 4(a)-(i)) utilized to determine employee labor is incremental	Elevated Voltage Work Performed
[redacted]	2005	97M010	Chief Line Mech A Htstick	First line internal employees	Conventional UG - Dist
[redacted]	2006	97M010	Chief Line Mech A Htstick	First line internal employees	
[redacted]		RETUN	Union Retiree w/ Benefits	First line internal employees	
[redacted]	2005	97M032	Distribution Inspector C	First line internal employees	Touch Potential Test - Dist, URD Inspections - Dist
[redacted]	2006	97M032	Distribution Inspector C	First line internal employees	
[redacted]	2005	97G051	Meter Shop Tester C	First line internal employees	Touch Potential Tests Dist
[redacted]	2006	97G051	Meter Shop Tester C	First line internal employees	
[redacted]	2005	97D019	Chief Cable Splicer A	First line internal employees	Conventional UG - Dist
[redacted]	2006	97D019	Chief Cable Splicer A	First line internal employees	
[redacted]	2005	977043	Junior Clerk	First line internal employees	Street Light Standard Insp - Dist, Inspection Admin - Dist
[redacted]	2006	97M122	Street Light Inspector	First line internal employees	
[redacted]	2005	973021	Meter Reader C	First line internal employees	Street Light Standard Insp - Dist, Inspection Admin - Dist
[redacted]	2006	97M122	Street Light Inspector	First line internal employees	
[redacted]	2005	97J054	Mechanic B	First line internal employees	OH Inspections Dist
[redacted]	2006	97J054	Mechanic B	First line internal employees	
[redacted]		97J058	Mechanic C	First line internal employees	
[redacted]	2005	97M032	Distribution Inspector C	First line internal employees	Touch Potential Tests- Dist, URD Inspections - Dist
[redacted]	2006	97M032	Distribution Inspector C	First line internal employees	Street Light Standard Insp - Dist, Convential UG - Dist
[redacted]	2005	97D019	Chief Cable Splicer A	First line internal employees	Conventional UG - Dist
[redacted]	2006	97D019	Chief Cable Splicer A	First line internal employees	
[redacted]	2006	97M122	Street Light Inspector	First line internal employees	URD Inspections-Dist, Convential UG-Dist, Street Light Sta
[redacted]	2005	97D010	Cable Splicer C	First line internal employees	UCD Inspections Dist
[redacted]	2006	97D010	Cable Splicer C	First line internal employees	
[redacted]	2005	97M032	Distribution Inspector C	First line internal employees	URD Inspections - Dist, UCD Inspections - Dist
[redacted]	2006	97M032	Distribution Inspector C	First line internal employees	Convential UG, Street Light Standard Insp - Dist
[redacted]	2005	97D010	Cable Splicer C	First line internal employees	Conventional UG - Dist, Inspection Admin - Dist
[redacted]	2006	97D010	Cable Splicer C	First line internal employees	
[redacted]	2005	97D019	Chief Cable Splicer A	First line internal employees	Conventional UG - Dist
[redacted]	2006	97D019	Chief Cable Splicer A	First line internal employees	
[redacted]	2005	97D019	Chief Cable Splicer A	First line internal employees	Convential UG - Dist, Inspection Admin - Dist
[redacted]	2006	97D019	Chief Cable Splicer A	First line internal employees	
[redacted]	2005	97D010	Cable Splicer C	First line internal employees	Convential UG - Dist, Inspection Admin - Dist
[redacted]	2006	97D010	Cable Splicer C	First line internal employees	
[redacted]	2005	97J058	Mechanic C	First line internal employees	Conventional UG - Dist
[redacted]	2006	97J058	Mechanic C	First line internal employees	
[redacted]	2005	97M028	Distribution Inspector B	First line internal employees	URD Inspections-Dist, Conventional UG - Dist
[redacted]	2006	97M028	Distribution Inspector B	First line internal employees	
[redacted]	2005	97J058	Mechanic C	First line internal employees	OH Inspections Dist, Conventional UG - Dist
[redacted]	2006	97D002	Cable Splicer A	First line internal employees	Inspection Admin - Dist
[redacted]		97J058	Mechanic C	First line internal employees	
[redacted]	2005	97D010	Cable Splicer C	First line internal employees	Conventional UG - Dist
[redacted]	2006	97D010	Cable Splicer C	First line internal employees	
[redacted]		97D019	Chief Cable Splicer A	First line internal employees	
[redacted]	2005	97M032	Distribution Inspector C	First line internal employees	Touch Potential tests - Dist, URD Inspections - Dist
[redacted]	2006	97M032	Distribution Inspector C	First line internal employees	
[redacted]	2005	97D019	Chief Cable Splicer A	First line internal employees	Conventional UG - Dist
[redacted]	2006	97D019	Chief Cable Splicer A	First line internal employees	
[redacted]	2005	973021	Meter Reader C	First line internal employees	Stray Voltage Tests Dist Muni
[redacted]		97M105	Utility Mechanic A	First line internal employees	
[redacted]	2006	97M105	Utility Mechanic A	First line internal employees	
[redacted]	2005	7470	Supervisor	A manager or supervisor explicitly hired for compliance with the program	Touch Potential Admin, Inspection Admin -Dist
[redacted]	2006	7470	Supervisor	A manager or supervisor explicitly hired for compliance with the program	Inspection Admin - Trans
[redacted]	2005	97M028	Distribution Inspector B	First line internal employees	Touch Potential Tests- Dist, URD Inspections - Dist
[redacted]	2006	97M028	Distribution Inspector B	First line internal employees	UCD Inspections - Dist, Conventional UG - Dist
[redacted]	2005	97J044	Maintenance Mechanic C	First line internal employees	Conventional UG - Dist
[redacted]	2006	97J006	Chief Maint Mech A	First line internal employees	
[redacted]		97J044	Maintenance Mechanic C	First line internal employees	
[redacted]	2005	97M032	Distribution Inspector C	First line internal employees	Touch Potential Tests Trans
[redacted]	2006	97M032	Distribution Inspector C	First line internal employees	

National Grid USA
Elevated Voltage Deferral
Direct Labor Charges (removed non-incremental employee charges)

Empl Name	Fiscal Yr	Job Cd	Job Cd Descr	Criteria (from response to Question 4(a)-®) utilized to determine employee labor is incremental	Elevated Voltage Work Performed
[redacted]	2005	97D014	Cable Splicer Helper	First line internal employees	Conventional UG - Dist
	2006	97D002	Cable Splicer A	First line internal employees	
		97D014	Cable Splicer Helper	First line internal employees	
	2005	97M032	Distribution Inspector C	First line internal employees	Street Light Standard Insp - Dist, Convential UG - Dist
	2006	97M032	Distribution Inspector C	First line internal employees	
	2005	97J044	Maintenance Mechanic C	First line internal employees	Conventional UG - Dist
	2006	97J044	Maintenance Mechanic C	First line internal employees	
	2005	97M032	Distribution Inspector C	First line internal employees	Touch Potential Tests - Dist, URD Inspections - Dist
	2006	97M032	Distribution Inspector C	First line internal employees	
	2005	97M032	Distribution Inspector C	First line internal employees	URD Inspections Dist
	2006	97M032	Distribution Inspector C	First line internal employees	
	2005	97D010	Cable Splicer C	First line internal employees	Conventional UG - Dist
	2006	97D010	Cable Splicer C	First line internal employees	
		97D018	Chief Cable Splicer A	First line internal employees	
		97D019	Chief Cable Splicer A	First line internal employees	
	2005	97D014	Cable Splicer Helper	First line internal employees	Conventional UG - Dist
		97T013	Tree Trimmer C	First line internal employees	
	2006	97D002	Cable Splicer A	First line internal employees	
		97D014	Cable Splicer Helper	First line internal employees	
	2005	97F095	Service Rep Helper	First line internal employees	Conventional UG - Dist
	2006	97D002	Cable Splicer A	First line internal employees	
		97D014	Cable Splicer Helper	First line internal employees	
		97F095	Service Rep Helper	First line internal employees	
	2005	97M028	Distribution Inspector B	First line internal employees	URD Inspections Dist
	2006	97M028	Distribution Inspector B	First line internal employees	
	2005	97M032	Distribution Inspector C	First line internal employees	URD Inspections Dist
	2006	97M032	Distribution Inspector C	First line internal employees	
	2005	97M028	Distribution Inspector B	First line internal employees	URD Inspections - Dist, Inspection Admin - Dist
	2006	97M028	Distribution Inspector B	First line internal employees	Inspection Admin - Trans
	2005	97M032	Distribution Inspector C	First line internal employees	Touch Potential Tests Trans
	2006	97M032	Distribution Inspector C	First line internal employees	
	2005	97M010	Chief Line Mech A Htstick	First line internal employees	OH Inspections Dist
	2006	97M010	Chief Line Mech A Htstick	First line internal employees	
	2005	97J044	Maintenance Mechanic C	First line internal employees	Conventional UG - Dist
	2006	97J044	Maintenance Mechanic C	First line internal employees	
	2005	97D019	Chief Cable Splicer A	First line internal employees	Conventional UG - Dist, Inspection Admin - Dist
	2006	97D019	Chief Cable Splicer A	First line internal employees	
	2005	97M028	Distribution Inspector B	First line internal employees	URD Inspections - Dist, Inspection Admin - Dist
	2006	97M028	Distribution Inspector B	First line internal employees	
	2005	97M010	Chief Line Mech A Htstick	First line internal employees	Touch Potential Tests Trans
	2006	97M010	Chief Line Mech A Htstick	First line internal employees	
	2005	97M032	Distribution Inspector C	First line internal employees	URD Inspections - Dist, Convential UG - Dist
	2006	97M032	Distribution Inspector C	First line internal employees	Inspection Admin - Dist
	2005	97M032	Distribution Inspector C	First line internal employees	URD Inspections Dist
	2006	97M032	Distribution Inspector C	First line internal employees	
	2005	97J058	Mechanic C	First line internal employees	Conventional UG - Dist
	2006	97J058	Mechanic C	First line internal employees	
	2005	97D019	Chief Cable Splicer A	First line internal employees	UCD Inspections Dist
	2006	97D019	Chief Cable Splicer A	First line internal employees	
	2005	97M010	Chief Line Mech A Htstick	First line internal employees	Touch Potential Tests Trans
	2006	97M010	Chief Line Mech A Htstick	First line internal employees	
	2005	97L033	Gas Mechanic Helper	First line internal employees	Conventional UG - Dist, Inspection Admin - Dist
	2006	97D002	Cable Splicer A	First line internal employees	
		97J062	Mechanic Helper	First line internal employees	
		97L033	Gas Mechanic Helper	First line internal employees	
	2005	97M045	Line Mechanic B	First line internal employees	URD Inspections - Dist, Convential UG - Dist
		97M048	Line Mechanic C	First line internal employees	Additional Systems Inspections
	2006	97M028	Distribution Inspector B	First line internal employees	
		97M045	Line Mechanic B	First line internal employees	
	2005	97D006	Cable Splicer B	First line internal employees	UCD Inspections - Dist, Conventional UG - Dist
	2006	97D006	Cable Splicer B	First line internal employees	
		97D010	Cable Splicer C	First line internal employees	

National Grid USA
Elevated Voltage Deferral
Direct Labor Charges (removed non-incremental employee charges)

Empl Name	Fiscal Yr	Job Cd	Job Cd Descr	Criteria (from response to Question 4(a)-(i)) utilized to determine employee labor is incremental	Elevated Voltage Work Performed
[redacted]	2005	5292	Prin IT Analyst	Internal work to develop new software systems to comply with the Order	Touch Potential Administration
	2006	5292	Prin IT Analyst	Internal work to develop new software systems to comply with the Order	
		8499	Manager	Internal work to develop new software systems to comply with the Order	
	2005	97J054	Mechanic B	First line internal employees	Conventional UG - Dist, Inspection Admin - Dist
	2006	97D002	Cable Splicer A	First line internal employees	
		97J054	Mechanic B	First line internal employees	
	2005	97D002	Cable Splicer A	First line internal employees	OH Inspections Dist, Conventional UG - Dist
	2006	97D002	Cable Splicer A	First line internal employees	Inspection Admin - Dist
		97D006	Cable Splicer B	First line internal employees	
	2005	97M028	Distribution Inspector B	First line internal employees	URD Inspections - Dist
	2006	97M028	Distribution Inspector B	First line internal employees	
	2005	974117	Office Technician C	First line internal employees	Stray Voltage Tests Dist Muni
		974118	Office Technician C	First line internal employees	
	2006	974118	Office Technician C	First line internal employees	
	2005	8622	Swr T & D	A manager or supervisor explicitly hired for compliance with the program	Touch Potential Administration
	2006	7470	Supervisor	A manager or supervisor explicitly hired for compliance with the program	
		8622	Swr T & D	A manager or supervisor explicitly hired for compliance with the program	
	2005	97D010	Cable Splicer C	First line internal employees	Conventional UG - Dist
	2006	97D010	Cable Splicer C	First line internal employees	
	2005	97J058	Mechanic C	First line internal employees	Conventional UG - Dist
	2006	97J058	Mechanic C	First line internal employees	
	2005	97J006	Chief Maint Mech A	First line internal employees	Conventional UG - Dist
	2006	97J006	Chief Maint Mech A	First line internal employees	
		97P030	Regional Operator A	First line internal employees	
	2005	97D006	Cable Splicer B	First line internal employees	Conventional UG - Dist, Inspection Admin - Dist
	2006	97D006	Cable Splicer B	First line internal employees	
		97M028	Distribution Inspector B	First line internal employees	
	2005	97M028	Distribution Inspector B	First line internal employees	Touch Potential Tests - Dist, URD Inspections - Dist
	2006	97M028	Distribution Inspector B	First line internal employees	
		RETUN	Union Retiree w/ Benefits	First line internal employees	
	2005	97D019	Chief Cable Splicer A	First line internal employees	Conventional UG - Dist
	2006	97D019	Chief Cable Splicer A	First line internal employees	

Exhibit___(SDL-4)

REDACTED

Date of Request___8/22/05___ Request No. _PSC-90 Gerbsch (DAG-3)_

NMPC Req. No. _95__

NIAGARA MOHAWK POWER CORPORATION
Case 01-M-0075 –Second CTC Reset Compliance Filing
Request for Information

FROM: PSC-90 Gerbsch (DAG)
(Information Requested By)

Request:

Schedule 35 of Attachment 7 shows a forecast for stray voltage deferral in (a) 2005 of $4,041,758; (b) 2006 of $5,370,029; and (c) 2007 of $5,370,029. A document distributed to staff on 8/15/05 includes the most recent cost estimates for the stray voltage and inspection programs for (a) FY '06 of $6,966,075 and (b) FY '07 of $6,228,950, not all of which the company considers incremental.

90. 4. Are there any former union or non-union employees that have been called back to perform the stray voltage and/or inspection work? If yes, please provide details of (a) who has been rehired, (b) why they had previously no longer worked for the company, and (c) the job for which they were rehired, and the associated rate of pay.

Response:

Please refer to the update to above numbers provided in response to PSC-87 Gerbsch (DAG-3).

Part 1 to the Question: Yes.

Part (a) to the Question: Refer to list below.

Part (b) of the Question:

Part (c) of the Question:

Name of Respondent: Scott Leuthauser Date of Reply: 10/20/05

Exhibit __ (SDL-5)

Niagara Mohawk
A National Grid Company

Scott D. Leuthauser
Vice President Distribution Planning
& Engineering

April 27, 2005

Mr. David S. Falletta
President/Business Manager/ Financial Secretary
Local Union 97, IBEW
3619 California Rd
Orchard Park, NY 14127

Dear Dave:

Pursuant to our discussions regarding the completion of stray voltage and inspection work, this document supersedes my April 20, 2005 letter, and is an addendum to the January 28, 2005 letter from Paul Cianchetti to Kevin Long regarding the retention of those employees affected by the AMR implementation. This addendum covers two groups of Western Division laid off employees; full time employees on the preferential rehire list and former part-time employees are listed on Attachment A of this letter. Except for what is specifically excluded in this addendum, the terms of the January 28, 2005 letter apply to the employees covered by this letter.

The employees from the rehire list will be placed in the newly created Street Light Inspector positions at pay group 5, step 2. These positions are full-time, temporary and the employees being placed in these positions are not eligible for those benefits outlined in Articles, IX, XII, XIII or XX of the labor agreement. These employees are not eligible for shift premiums or scheduled worker premiums (off hour) as outlined in Article VII. The job specification for this position is outlined in Attachment B of this letter. All street light inspection work to be assigned to these employees is within the job specification.

Employees placed in positions from the preferential rehire list will not be eligible for rights provided under the layoff provision of Appendix A, but will be returned to the preferential rehire list for the time remaining from their original date of layoff, less their active temporary service in this position. Employees declining these positions will not have their rehire status affected due to the temporary nature of these positions. Employees accepting a position covered by this understanding, who later choose to resign, will constitute resignation of employment.

The former part-time and probationary employees will be rehired as temporary employees and placed in the newly created Stray Voltage Tester position at pay group 1, student pay rate. The job specification for this position is outlined in Attachment C of this letter. These employees are not eligible for shift premiums or scheduled worker premiums (off hour) as outlined in Article VII. All street light stray voltage work assigned to these employees is within the job specification.

Unless assigned a Company vehicle, employees assigned to either job classification referenced above, will be required to arrive at the designated start time location on their own time. Employees will be required to use their own personal vehicles to travel to and from the locations of their daily work assignments and will be reimbursed for mileage driven while on company time in accordance with the mileage allowance in Article X. Employees will also be reimbursed for any parking fees or tolls incurred on company time.

At any time, the Company may place employees originally assigned to pay group 5 positions referenced above, in other temporary employment opportunities and maintain the same rate of pay. Such placements are solely at the Company's discretion and as it deems appropriate based on those tasks the Company determines the employee qualified to perform with appropriate training. Employees will report to the work location designated and the Company may alter the work location and/or assigned work of the employee as it deems necessary. Employees occupying the Street Light Inspector and Stray Voltage Tester positions cannot be displaced by other employees through the layoff provision of Appendix A. Employees originally assigned Stray Voltage Tester positions at the student pay grade 1, will only be used to perform the stray voltage testing and not be considered for other placements as stated above.

The placement of people in these positions will commence on Monday May 16, 2005. Please contact me if you have any questions.

Very truly yours,

Scott D. Leuthauser

Scott D. Leuthauser
Vice President
Distribution Planning & Engineering

xc: D. Walsh
P. Cianchetti
T. Rosbrook
J. Burke
K. Long – Local Union 97

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Syracuse, NY 13202
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Attachment A

Rehire List

Recalled to Part-time

Part time Employees

Probationary

Former Temporary

Attachment B

POSITION: Street Light Inspector

PAY GROUP: 5

DUTIES: Divisional

Under general supervision, perform prescribed duties to inspect street light facilities and record required detection and observational input. Make minor repairs for wiring deficiencies, prioritize all type of physical or electrical deficiencies and make work location safe (as needed). Maintain logs, records, databases. Conduct duties in accordance with required work completion schedule and established productivity standards.

QUALIFICATIONS:

- Must have ability to endure prolonged standing, walking, bending, kneeling and climbing;
- Must have ability to communicate with the public and co-workers in a tactful and effective manner; and
- Must possess and maintain a valid NYS driver's license.
- Must demonstrate a working knowledge of computer applications, record findings electronically (or manually)
- Must demonstrate ability to read circuit maps and / or physical location maps
- Must demonstrate a working knowledge or street light (circuits, operation, etc)
- Must be able to use hand tools / electrical tester

Note: This position is not subject to the inclement weather provisions of the labor agreement.

Attachment C

POSITION: Stray Voltage Tester

PAY GROUP: 1 – Student Pay Rate

DUTIES: Divisional

Under general supervision, perform prescribed duties of stray voltage detection related to electrical facilities. Observe electrical facilities and record required detection and observational input. Maintain logs, records and databases. Conduct duties in accordance with required work completion schedule and established productivity standards.

QUALIFICATIONS:

- Must have ability to endure prolonged standing, walking, bending, and climbing;
- Must have ability to communicate with the public and co-workers in a tactful and effective manner; and
- Must possess and maintain a valid NYS driver's license.
- Must demonstrate a working knowledge of computer applications, record findings electronically (or manually)
- Must demonstrate ability to read circuit maps and / or physical location maps
- Must demonstrate a general knowledge of equipment being tested for stray voltage
- Must be able to use hand tools / electrical tester

Note: This position is not subject to the inclement weather provisions of the labor agreement.

Exhibit___(SDL-6)

Exhibit__ (SDL-6)
Eight underground splicers hired to fortify the department to complete inspections

i) [redacted], to Cable Splicer A on 6/13/05 from Service Rep. A, which was backfilled through posting C01-042. He was initially hired to Company on 3/3/86.

ii) [redacted], to Cable Splicer Helper on 7/2/05 from Service Rep. Helper, which was backfilled through posting. He was initially hired to Company on 4/25/01.

iii) [redacted], to Cable Splicer A on 6/12/05 from Mechanic Helper Gas, which was backfilled through posting C05-046. He was initially hired to Company on 2/18/86.

iv) [redacted], to Cable Splicer A on 6/26/05 from Mechanic C which was not backfilled. He was initially hired to Company on 9/23/85.

v) [redacted], to Cable Splicer Helper on 7/10/05 from Service Rep. C which was backfilled through posting E05-66 initially hired to Company on 5/9/01.

vi) [redacted], to Chief Cable Splicer from Cable Splicer which was not backfilled. He was initially hired to Company 5/16/90

vii) [redacted], to Chief Cable Splicer from Cable Splicer which was not backfilled. He was initially hired to Company 8/23/89

viii) [redacted], to Cable Splicer A on 6/12/05 from Mechanic B which was not backfilled. He was initially hired to Company 3/3/86

Exhibits of Patrick M. Pensabene

Exhibit__(PMP-9)

Date of Request__9/5/06_ Request No. _PSC-341 Visalli (RAV-130)__

NMPC Req. No. _405_

NIAGARA MOHAWK POWER CORPORATION
Case 01-M-0075 – Second CTC Reset Compliance Filing
Request for Information

FROM: PSC-341 Visalli (RAV-130)___

Request:

On page 27, lines 7-8 of P. Pensabene's testimony, it is stated:

"Insurance claims directly resulting from major storms have historically been recorded as incremental major storm costs".

Regarding this statement, please provide the following information:

1. A copy of the relevant pages from the Company's pre-merger Accounting Manual or the applicable pre-Merger accounting instructions wherein this accounting/classification is called for.
2. A copy of the relevant pages from the Company's pre-merger Accounting Manual wherein the accounting for Injuries and Damages expense is provided.
3. The 2001 Expense Budget for "Executive/Storms" in the Asset Management & Energy Delivery Department shows $0 for cost component 160 (settlements). Since the 2001 Expense Budget was the basis for the Merger Rate Plan expense allowances, please explain the apparent discrepancy between the above testimonial statement and the Company's projections in the Merger filing.
4. The 2001 Energy Delivery Departmental Expense forecast for cost component 160 (insurance and claim costs) was $5.414 million. Please provide the backup to this forecast by activity and show how storm related claims were eliminated from this $5.414 million forecast.

Response (1 and 2):

The Company's General Ledger Accounting Manual (GLAM) was generally recognized as a reference tool for employees to follow for accounting instruction. While the GLAM did not provide specific accounting instructions, it did provide a brief summary of the types of costs that should be charged to individual cost components.

The Company provides Attachment 1 from the GLAM detailing ("Description") the types of costs that were classified as cost component (Code) 160 Insurance and Claims Costs and Injuries and Damages.

The Company's Claims Department determines whether incremental claims costs should be charged to the major storm.

Generally, the Claims Department reviews and denies claims from customers for spoiled food, damaged appliances and other damage from a major storm that were caused by circumstances beyond the Company's control.

Claims made by customers for landscaping damage, property damage (e.g. broken fences) or other types of damage caused by the Company's employees as a result of restoring power after a major storm are charged to the major storm. The Claims Department validates the claim prior to approving the reimbursement. The Claims Department's coding of claims costs to the major storm as a result of the Company's employees damaging customer property has been a historical practice.

Response 3:

The Company, for 2001 budget purposes, reflected all the incremental major storm costs as internal overtime as a proxy for all cost components that may be incurred in a major storm. Actual costs are charged to the specific cost categories (e.g. contractors, employee expenses, material costs, and other incremental costs that would have not incurred except for the major storm). The Company's 2000 budget for incremental major storm cost was prepared using the same approach as the 2001 budget.

Response 4:

The Company submits Attachment 2 supporting the 2001 Energy Delivery Departmental Expense forecast for cost component 160 (insurance and claim costs) by department and activity.

The Company believes that Attachment 2 demonstrates that the 2001 Energy Delivery Departmental Expense forecast for cost component 160 (insurance and claim costs) did not include major storm claims in base rates.

Name of Respondent: Patrick Pensabene   Date of Reply: 09/14/06

Form 103

NIAGARA MOHAWK

GENERAL LEDGER ACCOUNTING MANUAL

DOC. NO.	
PAGE	3 OF 8
DATE	1/1/94

SUBJECT	SECTION
COST COMPONENTS	AM.09

NIAGARA MOHAWK COST COMPONENTS SEGMENT (Cont'd)

CODE	DESCRIPTION

144 CONSULTING SERVICES - OTHER

The cost of all other outside consulting services except for those chargeable to cost components 140 through 143 and 145. Also used with all appropriate construction plant and 100 accounts. Examples would include actuarial services, planning, purchasing, human resources, consumer services, etc. Does not include Architect and Engineering consultants, testing services, etc. See cost component 170 for construction associated services and cost component 173 for Nuclear Architect and Engineering contracted services.

145 REGULATORY COMMISSION EXPENSES

For costs incurred in connection with formal cases before regulatory commissions, or other regulatory bodies to include consultants and other costs (e.g. newspaper advertising) associated with formal proceedings before regulatory bodies (P.S.C., F.E.R.C., etc.) and other expenses applicable to the regulation of the Company. If includable in expense, use account nos. 780/880.08 only. Also used with all appropriate construction plant and 100 accounts, if mandated by a regulatory body.

160 INSURANCE AND CLAIM COSTS

The cost of all insurance premiums for property, liability, etc. plus the cost of claims for personal injury and property damage including transportation claims not covered by insurance (includes legal fees and any other costs associated with claims). If includable in expense, use account nos. 780/880.09 for Insurance and 780/880.10 for Injuries and Damages. Also used with all appropriate construction plant and 100 accounts.

170 CONTRACTOR SERVICES - GENERAL

The cost of work performed under contract (both contract labor and material) by other companies or individuals. Examples include generating plant maintenance, fabrication of materials/equipment under contract, collection agency fees, routine inspections, tree trimming contractors, construction costs, etc. See cost components 173 and 174 for Nuclear and Non-Nuclear Architect and Engineering Contracted Services.

SUPERSEDES DOCUMENT DATED	AUTHORIZED BY	APPROVED BY
1/1/93	Manager - Ledgers and Reports	Vice President - Controller

sponse to PSC-341 (RAV-130); Question 4

01 Energy Delivery Departmental Expense for Cost Component 160

of EXPND_TOTAL_BUDGET_DOLLARS			
Cost Center Name	Activity Number	Activity Name	Total
MS	E09640	MOTOR VEHICLE CLAIM PAYMENTS	399,600
	E09740	RADIO WORK-COMPANY EQUIPMENT	-
	E09765	SUBSTATION OPERATIONS	-
	E09795	CLAIMS INVESTIGATION & SETTLEMENT	4,102,000
MS Sum			**4,501,600**
S CANCELED/SUSPENDED CHARGES	E00021	SUSPENDED CONSTR. OR	-
S CANCELED/SUSPENDED CHARGES Sum			**-**
CTOR CENTRAL DIV FIELD OPERATIONS	E09619	GAS LEAK - SERVICES	-
CTOR CENTRAL DIV FIELD OPERATIONS Sum			**-**
CTOR WESTERN DIV FIELD OPERATIONS	E09795	CLAIMS INVESTIGATION & SETTLEMENT	-
CTOR WESTERN DIV FIELD OPERATIONS Sum			**-**
RIBUTION DESIGN-MOHAWK VALLEY REGION	E09629	GENERAL-ADMIN, SUPERVISION & OTHER	-
RIBUTION DESIGN-MOHAWK VALLEY REGION Sum			**-**
REL-AIR TRAVEL GROUP INSURANCE	E09598	EMPLOYEE SERVICES-EMPLOYEE BENEFITS	20,000
REL-AIR TRAVEL GROUP INSURANCE Sum			**20,000**
RGY TRANSACTIONS - DIR #REPL 5/99#	E09668	PROPERTY INSURANCE PREMIUMS	-
RGY TRANSACTIONS - DIR #REPL 5/99# Sum			**-**
OPERATIONS - BEACON NORTH	E08101	CORROSION CONTROL - GAS MAINS	-
	E09617	GAS LEAK - MAINS	-
OPERATIONS - BEACON NORTH Sum			**-**
OPERATIONS - ROME/ONEIDA	E09628	GAS DEPT.-OPERATION & MAINTENANCE	-
OPERATIONS - ROME/ONEIDA Sum			**-**
OPERATIONS ALBANY	E08108	ODORIZER WORK	-
	E09628	GAS DEPT.-OPERATION & MAINTENANCE	-
OPERATIONS ALBANY Sum			**-**
OPERATIONS GLENS FALLS	E09619	GAS LEAK - SERVICES	-
OPERATIONS GLENS FALLS Sum			**-**
OPERATIONS GLOVERSVILLE	E09617	GAS LEAK - MAINS	-
OPERATIONS GLOVERSVILLE Sum			**-**
OPERATIONS SCHENECTADY	E08105	VALVE REPAIRS	-
	E09617	GAS LEAK - MAINS	-
OPERATIONS SCHENECTADY Sum			**-**
OPERATIONS TROY	E09617	GAS LEAK - MAINS	-
	E09619	GAS LEAK - SERVICES	-
OPERATIONS TROY Sum			**-**
RMATION RESOURCES	E09795	CLAIMS INVESTIGATION & SETTLEMENT	-
RMATION RESOURCES Sum			**-**
RANCE MANAGER & STAFF	E09668	PROPERTY INSURANCE PREMIUMS	-
	E09923	INJURIES & DAMAGES	-
RANCE MANAGER & STAFF Sum			**-**
RANCE PREMIUMS	E00170	NMP2 O&M CO-TENENT CREDIT	592,600
	E09668	PROPERTY INSURANCE PREMIUMS	1,149,600
	E09923	INJURIES & DAMAGES	3,315,800
	E24011	NUCLEAR PROPERTY INSURANCE	(5,042,100)
	E24014	INJURIES AND DAMAGES-NUCLEAR	616,900
RANCE PREMIUMS Sum			**632,800**
	E09668	PROPERTY INSURANCE PREMIUMS	-
	E09795	CLAIMS INVESTIGATION & SETTLEMENT	75,000
/ Sum			**75,000**
CLEARANCE SOUTHWEST	E00244	REIMBURSABLE EXP. OF TRANSFERRED EMPL.	-
CLEARANCE SOUTHWEST Sum			**-**
CLEARANCE-CAPITAL	E09281	Invalid Activity - CONSCO	-
CLEARANCE-CAPITAL Sum			**-**
IAWK VALLEY METER READING	E09700	METER READING	-
IAWK VALLEY METER READING Sum			**-**
ETY-WORKER'S COMPENSATION PREMIUMS	E00170	NMP2 O&M CO-TENENT CREDIT	(147,000)
	E09806	WORKERS COMP. INSURANCE PREMIUM PAYMENTS	66,200
	E24010	WORKERS' COMPENSATION-NUCLEAR	205,700
ETY-WORKER'S COMPENSATION PREMIUMS Sum			**124,900**
ES & SERVICE-UTICA	E00014	ELECTRIC SERVICE RESTORATION	-
ES & SERVICE-UTICA Sum			**-**
IOR VP- ASSET MGM'T & ENERGY DELIVERY	E53418	NORTH COUNTRY ICE STORM	-
IOR VP- ASSET MGM'T & ENERGY DELIVERY Sum			**-**
TEM PUBLIC RELATIONS	E09528	TELECOMMUNICATIONS COSTS	-
TEM PUBLIC RELATIONS Sum			**-**
COBLESKILL	E00014	ELECTRIC SERVICE RESTORATION	-
COBLESKILL Sum			**-**
GLOVERSVILLE	E00014	ELECTRIC SERVICE RESTORATION	-
GLOVERSVILLE Sum			**-**

sponse to PSC-341 (RAV-130); Question 4

01 Energy Delivery Departmental Expense for Cost Component 160

of EXPND_TOTAL_BUDGET_DOLLARS			
Cost Center Name	Activity Number	Activity Name	Total
NORTHEAST	E00014	ELECTRIC SERVICE RESTORATION	-
	E07882	Invalid Activity - CONSCO	-
NORTHEAST Sum			
SARATOGA	E00014	ELECTRIC SERVICE RESTORATION	-
SARATOGA Sum			-
SCHENECTADY	E00146	Invalid Activity - CONSCO	-
	E09678	LINE AND UNDERGROUND O & M	-
SCHENECTADY Sum			
WARRENSBURG/TICONDEROGA	E90098	HURRICANE FLOYD - EAST	-
WARRENSBURG/TICONDEROGA Sum			
-ALBANY	E00014	ELECTRIC SERVICE RESTORATION	-
	E09678	LINE AND UNDERGROUND O & M	-
	E09795	CLAIMS INVESTIGATION & SETTLEMENT	-
	E09797	RIGHT OF WAY RENTAL PAYMENTS	-
	E09805	MAINTENANCE ASSOCIATED WITH CONSTRUCTION	-
	E69600	Invalid Activity - CONSCO	-
	E94030	6/2/2000 STORM	-
-ALBANY Sum			-
-CORTLAND	E93857	T&D MAINT - FIX GROUNDS	-
-CORTLAND Sum			
-HINSDALE	E00014	ELECTRIC SERVICE RESTORATION	-
	E09619	GAS LEAK - SERVICES	-
-HINSDALE Sum			-
-ONEIDA	E00014	ELECTRIC SERVICE RESTORATION	-
-ONEIDA Sum			-
-ROME	E00014	ELECTRIC SERVICE RESTORATION	-
-ROME Sum			-
-UNDERGROUND	E09784	UNDERGROUND FACILITIES MAINTEN	-
-UNDERGROUND Sum			-
-UTICA	E00014	ELECTRIC SERVICE RESTORATION	-
UTICA Sum			-
NSPORTAION OTHER - AVIATION	E09663	MATERIAL REQUIREMENTS PLANNING ADMIN	-
	E09668	PROPERTY INSURANCE PREMIUMS	60,000
	E09923	INJURIES & DAMAGES	-
NSPORTAION OTHER - AVIATION Sum			**60,000**
nd Total			**5,414,300**