

Niagara Mohawk Power Corporation  
d/b/a National Grid

PROCEEDING ON MOTION OF THE  
COMMISSION AS TO THE RATES,  
CHARGES, RULES AND  
REGULATIONS OF NIAGARA  
MOHAWK POWER CORPORATION  
FOR ELECTRIC AND GAS SERVICE

Rebuttal Testimony and Exhibits of:

Electric Rate Design Panel  
Electric Infrastructure and Operations Panel  
Service Company Panel  
Michael E. Barrett

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Submitted by:  
Niagara Mohawk Power Corporation



**Before the Public Service Commission**

**NIAGARA MOHAWK POWER CORPORATION d/b/a NATIONAL GRID**

**Rebuttal Testimony**

**of the**

**Electric Rate Design Panel**

**Case 12-E-0201**

**Rebuttal Testimony of the Electric Rate Design Panel**

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**Rebuttal Testimony of the Electric Rate Design Panel**

1 **Q. Please identify the members of the Electric Rate Design Panel**  
2 **(“Panel”) and indicate on whose behalf the Panel is testifying.**

3 A. The Panel consists of Pamela Dise, Kellie Smith, and Howard Gorman.  
4 The Panel is testifying on behalf of Niagara Mohawk in rebuttal to  
5 testimony filed on behalf of the Department of Public Service Staff  
6 (“Staff”) and Multiple Intervenors (“MI”).

7

8 **Q. Is this the Electric Rate Design Panel that submitted direct testimony**  
9 **and corrections and updates testimony in this proceeding?**

10 A. Yes, it is.

11

12 **I. Overview of Rebuttal Testimony**

13 **Q. What is the purpose of the Panel’s rebuttal testimony?**

14 A. The purpose of the Panel’s rebuttal testimony is to respond to certain  
15 issues raised in the testimony of the Staff Electric Rate Panel (“SERP”)  
16 and Mr. Jeffry Pollock on behalf of MI. In addition, the Panel addresses  
17 the Company’s proposal to defer and recover reliability support services  
18 (“RSS”) costs. Specifically, the Panel addresses the following issues:

19

20 **A. ECOSS Issues**

21 

- Staff’s recommendation that, for purposes of revenue

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1 allocation and rate design, the Commission should rely on the  
2 Embedded Cost of Service Study (“ECOSS”) submitted by the  
3 SERP as Exhibit \_\_\_ (SERP-1 Corrected). (See SERP  
4 testimony at 8, ll. 1-16). The Company’s ECOSS and the  
5 ECOSS supported by the SERP use the same methodology and  
6 differ only in that (1) the SERP recommends using Historic  
7 Test Year information as the basis for the ECOSS, while the  
8 Company uses Rate Year information, and (2) Staff and the  
9 Company use different methodologies to allocate the cost of  
10 line transformers and related accounts, as discussed  
11 immediately below.

- 12 • The SERP’s recommendation that the line transformer plant  
13 account (Account 368) and related accounts be classified and  
14 allocated using a zero-intercept approach, as was done for other  
15 distribution plant accounts (Accounts 364-367). (SERP  
16 testimony at 10, ll.4-17). The Company’s ECOSS assigned  
17 line transformers among the rate classes by identifying which  
18 rate classes are served by each line transformer.
- 19 • MI Witness Pollock’s recommendation to modify the  
20 Company’s ECOSS-CU by allocating the Primary and  
21 Secondary Distribution Systems to Demand and Customer in

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1 the same proportions (MI testimony at 19, ll. 17-23). The  
2 Company’s ECOSS recognized that the systems serve different  
3 purposes, and thus classified a lower proportion of the systems  
4 to Customer for the Primary System (50 percent) than for the  
5 Secondary System (62 percent).

- 6 • Mr. Pollock’s recommendation that Distribution Load  
7 Dispatching costs (Account 581) be allocated on the basis of  
8 non-coincident peak (“NCP”), and that none of the costs be  
9 allocated to SC-3/3A customers taking service at Sub-  
10 transmission or Transmission levels (MI testimony at 17, ll. 8-  
11 15). The Company’s ECOSS allocates this item to all rate  
12 classes based on MWh.

13

14 **B. Revenue Allocation/Rate Design**

- 15 • The SERP’s approach to revenue allocation is the same as the  
16 Panel’s, except that the SERP relies on an Historic Test Year  
17 ECOSS. The Panel maintains that its Rate Year ECOSS  
18 should be used. If, however, the Commission accepts Staff’s  
19 proposal to use an Historic Test Year ECOSS for revenue  
20 allocation, the ECOSS provided as Exhibit \_\_\_\_ (E-RDP-1R)  
21 should be used because it corrects two minor errors in the

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1                   ECOSS used by Staff. In addition, if the Commission accepts  
2                   Staff’s proposed revenue requirement, the Panel agrees with  
3                   Staff that no revenue allocation constraints should be applied  
4                   for any rate class.

- 5                   • Mr. Pollock’s recommendation that the Commission use his  
6                   alternative ECOSS as a guide in revenue allocation. The  
7                   Company disagrees with the changes Mr. Pollock recommends  
8                   be made to its ECOSS-CU and thus does not support the use of  
9                   his alternative ECOSS for revenue allocation purposes.
- 10                  • Mr. Pollock’s recommendation that the customer charge for  
11                  SC-3A be increased (MI testimony at 37, Table 6).

12

13                  **C. Merchant Function Charge**

- 14                  • Staff’s recommendation that the Company change its  
15                  calculation of two components of the Merchant Function  
16                  Charge (“MFC”). First, Staff recommends that the  
17                  uncollectibles component be based on an average of the most  
18                  recent three years, as discussed in the testimony of the Staff  
19                  Accounting Panel, rather than one year as recommended by the  
20                  Company. Second, Staff takes the position that the “Other  
21                  Customer Capital Rate” should be used to determine the return

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1 requirement on commodity-related working capital, rather than  
2 utilizing the authorized weighted average cost of capital, as  
3 proposed by the Company.

- 4 • The need to update (1) Staff’s calculation of the credit and  
5 collections component of the MFC to reflect Staff’s revised  
6 purchase of receivables (“POR”) sales forecast and revenue  
7 requirement, (2) Staff’s calculation of the supply procurement  
8 component of the MFC to reflect Staff’s revised revenue  
9 requirement, and (3) the Company’s delivery/commodity  
10 allocation of uncollectibles expense in the ECOSS to reflect  
11 Staff’s revised revenue forecast.

12  
13 **D. Historic Demand**

- 14 • Mr. Pollock’s recommendation that Historic Demand be  
15 eliminated for all customers receiving Expansion Power (“EP”)  
16 and Replacement Power (“RP”), rather than waiting until those  
17 customers are paying standard tariff delivery rates.

18  
19 **E. Revenue Forecast**

- 20 • Staff’s recommendation that the Rate Year revenue forecast be  
21 adjusted using an alternative electric sales forecast. Staff’s

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1 recommended total operating revenues are \$2.420 billion  
2 versus the Company's proposed total operating revenues of  
3 \$2.428 billion.

4

5 **F. Reliability Support Services Costs**

- 6 • The Company's recommendation, as discussed in the rebuttal  
7 testimony of the Electric Infrastructure and Operations Panel  
8 ("EIOP"), that a surcharge be implemented to recover RSS  
9 costs remaining to be reconciled or incurred from April 1, 2013  
10 on.

11

12 **Q. Is the Panel sponsoring any exhibits as part of its rebuttal testimony?**

13 A. Yes. The Panel is sponsoring three exhibits, which were prepared by or  
14 under the supervision of one or more members of the Panel:

- 15 • Exhibit \_\_\_ (E-RDP-1R), which is the Historic Test Year  
16 ECOSS that Staff originally asked the Company to provide in  
17 response to DPS-338 (LAR-4), but with minor corrections;
- 18 • Exhibit \_\_\_ (E-RDP-2R), the Company's narrative response to  
19 Information Request MI-125 (MM-125) and Attachment 2 to  
20 that response, which provides the results of the Company's  
21 Rate Year ECOSS to correct the ECOSS-CU for an error in the

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1 calculation of the Demand allocators; and

- 2 • Exhibit \_\_\_ (E-RDP-3R), a tariff leaf to address the  
3 Company’s proposed RSS surcharge.  
4

5 **II. Proposed Changes to the ECOSS**

6 **A. Use of Historic Test Year or Rate Year Information**

7 **Q. Does the Company agree with the SERP’s proposed use of an ECOSS**  
8 **based on Historic Test Year information, rather than Rate Year**  
9 **information?**

10 A. No. The Company maintains that the ECOSS submitted with its  
11 Corrections and Updates Testimony, as updated in Exhibit \_\_\_ (E-RDP-  
12 2R), should be utilized as the basis for revenue allocation and rate design  
13 for a number of reasons, including the fact that the rates being designed in  
14 this proceeding are based on the Rate Year revenue requirement.  
15

16 **Q. What is the basis for the SERP’s recommendation that the**  
17 **Commission should use an ECOSS based on the Historic Test Year,**  
18 **rather than the Rate Year?**

19 A. The SERP asserts that an ECOSS based on historic costs and revenues  
20 should be used because an ECOSS based on a pro forma year “has the  
21 potential to introduce errors because [it is] based upon forecasts of future

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1 costs and revenues.” The SERP further argues that “using a forecast pro  
2 forma study requires that the study be updated after the Commission  
3 renders its final rate case determination,” and that they “prefer using the  
4 historic ECOSS study since all costs and cost allocators are known and  
5 updates are not required.” (SERP testimony at 8, ll.1-16).

6

7 **Q. Does the Company disagree with the SERP on this point?**

8 A. Yes. There are several flaws in the SERP’s reasoning. First, the  
9 uncertainty inherent in a forecast does not make the forecast unusable;  
10 rather, it merely requires that care be taken in how the forecast is used.  
11 The Company’s ECOSS reflects the Company’s *actual* Rate Year revenue  
12 requirement, thereby capturing the known and measurable changes that  
13 will occur between the Historic Test Year and when new rates are  
14 established. These changes are not reflected in an ECOSS that is based  
15 solely on historic data. The Rate Year data used in the Company’s  
16 ECOSS provides the basis for the rates that the Commission will set and it  
17 is logical and appropriate to design those rates using the same information.

18

19 Second, although the ECOSS supported by the SERP reflects some  
20 adjustments to the Historic Test Year, it does not reflect all appropriate  
21 adjustments. For example, sales and revenue have not been weather

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1 normalized. The Company's ECOSS reflects normalized sales and other  
2 known and measurable adjustments.

3  
4 Third, if the ECOSS is not based on the Rate Year revenue requirement,  
5 forecast Rate Year returns cannot be computed, which means that the  
6 effectiveness of the proposed revenue allocation in moving toward cost of  
7 service, as measured by progress toward unity in the Rate Year, cannot be  
8 quantified.

9  
10 Finally, updating the ECOSS after the Commission renders its order is a  
11 small price for having more relevant information. Contrary to Staff's  
12 belief, updating the ECOSS is not a major undertaking—the turnaround  
13 time to update the ECOSS is usually one or two days. Notably, in the  
14 Company's 2010 Electric Rate Case, the ECOSS was based on Rate Year  
15 information and there was no difficulty or delay in updating it.

16

17 **Q. If the Commission determines that it is appropriate to rely on an**  
18 **ECOSS based on the Historic Test Year, does the SERP's ECOSS**  
19 **reflect the appropriate revenue?**

20 A. The revenue adjustments reflected in the SERP's ECOSS, (SERP  
21 testimony at 11, Lines 16-23) are necessary and appropriate, but sales and

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1 revenues would need to be weather normalized.

2

3 **Q. Please describe Exhibit \_\_\_ (E-RDP-1R).**

4 A. Exhibit \_\_\_ (E-RDP-1R) is the Historic Test Year ECOSS relied on by the  
5 SERP and provided in the Company's response to Information Request  
6 DPS-338 (LAR-4), but with two minor corrections. (This corrected  
7 version of the ECOSS was provided with the Company's second  
8 supplemental response to LAR-4.) First, the ECOSS in the original  
9 response to LAR-4 included incorrect amounts for Historic Test Year  
10 Cash Working Capital, Cash Working Capital – Commodity, and the  
11 Earnings Base Adjustment. Second, the Panel recently became aware of  
12 an error in the calculation of the Demand allocators used in performing the  
13 ECOSS.

14

15 **Q. Do these corrections affect the results of the Historic Test Year**  
16 **ECOSS?**

17 A. The effects of the corrections are not significant, and the Company  
18 believes that the impact on Staff's recommendations, which were based on  
19 the original Historic Test Year ECOSS, are negligible. As reflected in  
20 Exhibit \_\_\_ (E-RDP-1R), the corrected class rates of return (Line 30) are  
21 very close to those in the original version of the Historic Test Year

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1           ECOSS (Line 31). Similarly, the relative class rates of return in the  
2           corrected Historic Test Year ECOSS (Line 34) are very close to the  
3           original relative rates (Line 35). As discussed in the response to LAR-4  
4           Supplemental 2, the overall rate of return decreased from 4.68 percent to  
5           4.52 percent because of the higher rate base in the corrected ECOSS.  
6

7   **Q.   Do these corrections affect the Company's Rate Year ECOSS?**

8   A.   The error in the calculation of the Demand allocators had a small impact  
9       on the results of the original Rate Year ECOSS and ECOSS-CU. Exhibit  
10      \_\_\_ (E-RDP-2R) provides the results of an updated version of the study.  
11      As reflected in the exhibit, the impact is minimal—the corrected Rate  
12      Year class rates of return (Line 32) are very close to those in the original  
13      Rate Year ECOSS (Line 33), the relative class rates of return in the  
14      corrected Rate Year ECOSS (Line 34) are very close to the original  
15      relative returns (Line 35), and the revenue increases and decreases  
16      required to achieve the target rate of return (Line 37) are very close to the  
17      original increases and decreases (Line 38).

18

19   **B.   Line Transformers**

20   **Q.   The SERP recommends that the plant account for line transformers**  
21   **(Account 368) and the line transformer-related portions of the**

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1           **Accumulated Depreciation, Maintenance and Depreciation Expense**  
2           **accounts (Accounts 364-367) be classified and allocated using an**  
3           **approach similar to a zero intercept study. How did the Company**  
4           **assign these costs among the rate classes?**

5    A.    The Company's ECOSS assigned line transformers among the rate classes  
6           by identifying which rate classes are served by each specific line  
7           transformer based on information from the Company's Geographic  
8           Information System. The cost of each line transformer (using current  
9           replacement cost) was allocated among the classes served based on the  
10          average NCP load for each rate class.

11

12   **Q.    Why does the Panel believe that its approach to assigning line**  
13          **transformers and related facilities among the rate classes is**  
14          **preferable?**

15    A.    The Panel directly assigned costs to the customers served by each line  
16          transformer, whereas the SERP used an allocation of costs. An allocation  
17          should be used only when more precise information cannot be obtained; in  
18          this case, more precise information was available and was used by the  
19          Panel. Importantly, in the Company's 2010 Electric Rate Case, the  
20          Commission relied on an ECOSS that used this direct assignment  
21          approach for line transformers and related costs.

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1           **C.     Customer Component of Primary Distribution System**

2   **Q.     Please explain MI Witness Pollock’s position regarding the**  
3           **classification of the Primary Distribution System in the Company’s**  
4           **ECOSS.**

5   A.     Mr. Pollock argues that the ECOSS should use the same  
6           Demand/Customer split for the Primary and Secondary Distribution  
7           Systems. Based on Mr. Pollock’s recommendation, the portion of the  
8           Distribution Plant in FERC Accounts 364-367 classified to the Customer  
9           component for the Primary Distribution System would increase from the  
10          Company’s proposed 50 percent to 61.28 percent. These percentages are  
11          weighted averages based on a composite of these four accounts.

12  
13 **Q.     Did any party propose changes to the Company’s methodology for**  
14           **determining the Demand/Customer split for the Secondary**  
15           **Distribution System?**

16 A.     No. The Panel set the Customer component of the Secondary System  
17           equal to the Labor portion of capital projects over the past four years and  
18           the Demand component equal to the balance. No party objected to this  
19           method or to the calculation.

20  
21 **Q.     Why does Mr. Pollock recommend that the Customer component of**

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1           **the Primary and Secondary Distribution Systems should be the same?**

2    A.    Mr. Pollock’s recommendation is based on the mistaken belief that the  
3           Primary and Secondary Distribution Systems use the same equipment, that  
4           the only difference between them is the voltage levels at which they are  
5           operated, and that because Primary and Secondary Distribution plant costs  
6           are assigned to the same FERC accounts they should be treated the same  
7           in the ECOSS. Contrary to Mr. Pollock’s testimony, and as explained by  
8           the Panel in its direct testimony, there are substantial differences between  
9           the Primary and Secondary Distribution Systems that support classifying  
10          them differently.

11

12   **Q.    Please explain.**

13   A.    As confirmed in the rebuttal testimony of the EIOP, there are substantial  
14          differences between the equipment used and the functions served by the  
15          Primary and Secondary Distribution Systems. For example, the Primary  
16          System uses voltage regulators, cross-arms, switch enclosures, and  
17          disconnect switches, while the Secondary System does not. This  
18          equipment adds substantial capital cost to the Primary System and is not  
19          Customer-related. The Primary and Secondary Distribution Systems also  
20          differ in the main roles they serve in the Company’s distribution system.  
21          The Primary portion of the distribution system serves several purposes:

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- 1                   1. It is the backbone of the overall distribution system, moving  
2                    electricity from the transmission/sub-transmission substations  
3                    to and through local areas, almost as an extension of the  
4                    transmission/sub-transmission system. The Primary System  
5                    also has the role of tying together subsystems for reliability  
6                    during storms or service interruptions. This portion of the  
7                    Primary System represents an estimated one-quarter of Primary  
8                    circuit miles.
- 9
- 10                  2. It branches to continue moving electricity to local areas  
11                  (estimated to be less than a quarter of Primary circuit miles) or  
12                  it moves electricity through step-down transformers to the  
13                  Secondary System and then to customers taking service at  
14                  Secondary voltage (estimated to be half of Primary circuit  
15                  miles).
- 16
- 17                  3. It connects Primary-voltage customers, typically large end-  
18                  users, to the distribution system. This portion of the Primary  
19                  System represents less than one percent of Primary circuit  
20                  miles.
- 21

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1 In contrast, the main purpose of the Secondary System is to connect the  
2 majority of customers that take service at Secondary voltages to the  
3 Primary Distribution System.

4  
5 **Q. What conclusions should be drawn from these differences between the**  
6 **Primary and Secondary Systems?**

7 A. The information above shows that the Customer-related portion of the  
8 Primary System, that is, the portion that supports attaching customers, is  
9 different from that of the Secondary System. Based on the functions it  
10 serves, it is reasonable to classify approximately one-half of the Primary  
11 Distribution System as Customer-related since 50 percent of the circuit  
12 miles move electricity through step-down transformers to the Secondary  
13 System.

14  
15 **Q. Does the fact that the Primary and Secondary Systems are recorded**  
16 **in the same FERC accounts have any consequences for how they**  
17 **should be classified in the ECOSS?**

18 A. No. The purpose of the ECOSS analysis is to understand cost causation,  
19 and therefore it does not simply rely on account titles.

20

21

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1           **D.     Distribution Load Dispatching Expenses**

2   **Q.     MI Witness Pollock objects to the Company's allocation of**  
3           **Distribution Load Dispatching costs in its ECOSS. What is the**  
4           **Company's response?**

5   A.     The Company's ECOSS allocates Distribution Load Dispatching costs  
6           (Account 581) to all rate classes based on MWh, while Mr. Pollock  
7           recommends that this item be allocated on the basis of NCP and that none  
8           of these costs be allocated to SC-3/3A customers taking service at sub-  
9           transmission or transmission levels. Mr. Pollock's position is based on the  
10          fact that these costs are 95 percent Labor and his mistaken belief that the  
11          expense is primarily incurred to meet peak loads. He also cites the  
12          NARUC Electric Utility Cost Allocation Manual and practice at other  
13          New York State utilities.

14  
15          Contrary to Mr. Pollock's assertions, as the EIOP confirms in its rebuttal  
16          testimony, Distribution Load Dispatch is an activity that must be  
17          performed minute-by-minute, not just during peak periods, because it  
18          supports system reliability, which must be maintained at all times. The  
19          main determinant for staffing levels, and therefore labor costs, for  
20          Distribution Load Dispatch is the amount of maintenance work being done  
21          on the system at a given time because operator actions are required to

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1 coordinate maintenance work with line loading, and to divert load when  
2 necessary, in addition to managing supply and delivery of electricity. The  
3 variability of this cost is illustrated by the fact that staffing levels, while  
4 stable during the daytime, are lower at night and sometimes on weekends,  
5 when maintenance work is not performed.

6

7 **Q. How does the manner in which Distribution Load Dispatch operating**  
8 **expense is incurred compare to capital costs for distribution system**  
9 **assets?**

10 A. As Mr. Pollock notes in his testimony, capital costs must be incurred so  
11 the system can meet peak demands; once they are incurred the ability to  
12 handle non-peak loads is a by-product. The same is *not* true of the labor  
13 costs incurred for Distribution Load Dispatch; those costs can be, and are,  
14 incurred based on *daily* conditions. That is, the resources (and, therefore,  
15 the costs incurred) to perform the Distribution Load Dispatch function at  
16 the peak are not available on a constant basis—at peak and non-peak  
17 times—to perform the function. Rather, the costs need to be incurred each  
18 day and at different levels during various time periods.

19

20 **Q. What does this imply for the allocation of Distribution Load Dispatch**  
21 **costs?**

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1 A. Because Distribution Load Dispatch costs are not caused by peak period  
2 conditions, but instead are caused by daily conditions on the distribution  
3 system, allocating this cost based on MWh, as the Company's ECOSS  
4 does, much more closely reflects cost causation than allocating it based on  
5 NCP, as recommended by Mr. Pollock. Therefore, the Commission  
6 should accept the allocation methodology for Distribution Load Dispatch  
7 costs used in the Company's ECOSS.

8

9 **Q. What reason does Mr. Pollock give for his recommendation not to**  
10 **allocate Distribution Load Dispatch to SC-3/3A customers taking**  
11 **service at sub-transmission or transmission levels?**

12 A. Mr. Pollock states these customers do not use the distribution system.

13

14 **Q. Is Mr. Pollock correct?**

15 A. No. Mr. Pollock's recommendation wrongly assumes that the rate class  
16 names (*i.e.*, Sub-transmission and Transmission) equate to Operational  
17 Control function. On the contrary, the Distribution Load Dispatch  
18 function is required for operational control purposes for all customers  
19 served at less than 115kV, which is the dividing line between  
20 Transmission Operation Control (which includes the Transmission Load  
21 Dispatch function) and Distribution Operation Control (which includes the

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1 Distribution Load Dispatch function). Only a very few customers take  
2 service at 115kV or above and do not use Distribution Load Dispatch.  
3 Therefore, the Company believes that its ECOSS properly and reasonably  
4 allocates this cost to the correct rate classes.

5

6 **E. MI's Alternative ECOSS**

7 **Q. What is the Panel's recommendation regarding the alternative**  
8 **ECOSS presented by Mr. Pollock?**

9 **A.** The Panel recommends the Commission use the Company's study, not the  
10 one prepared by Mr. Pollock, as the basis for revenue allocation and rate  
11 design. Except for the two items noted above, Mr. Pollock supports the  
12 methodology used by the Company in its ECOSS.

13

14 **III. Revenue Allocation/Rate Design**

15 **A. Historic Test Year ECOSS**

16 **Q. In its overview, the Panel identified that certain corrections would**  
17 **need to be made if the Commission determines that an Historic Test**  
18 **Year ECOSS should be used for revenue allocation. Please explain.**

19 **A.** If the Commission accepts Staff's proposal to use an Historic Test Year  
20 ECOSS, the ECOSS submitted with the Company's second supplemental  
21 response to DPS-338 (LAR-4) and summarized in Exhibit \_\_\_ (E-RDP-

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1 1R) should be used because it corrects the two minor errors discussed  
2 above.

3

4 **B. Support for SERP Revenue Allocation**

5 **Q. Does the Panel agree that, if the Commission approves Staff's**  
6 **proposed revenue requirement, no revenue allocation constraints**  
7 **should be applied for any rate class?**

8 A. Yes. If the Commission accepts the Staff revenue requirement as  
9 presented on Exhibit \_\_\_ (SAP-1 Corrected), total transmission and  
10 distribution revenue would decrease by 0.2 percent (Exhibit \_\_\_ (SERP-1  
11 Corrected), Line 17). While the Panel endorses the concept of gradualism,  
12 if the revenue change approved by the Commission is small, there is no  
13 need to limit class increases or decreases. The purpose of gradualism is to  
14 mitigate extreme rate impacts. Limiting rate class increases when  
15 unnecessary would undermine the realignment step of revenue allocation,  
16 which is important in moving rate classes closer to their cost of service.

17

18 **C. Customer Charges for SC-3 and SC-3A**

19 **Q. What does Mr. Pollock recommend regarding customer charges?**

20 A. Mr. Pollock recommends that customer charges for SC-3A customers be  
21 increased to the amounts shown in the Primary Customer, Secondary

**Rebuttal Testimony of the Electric Rate Design Panel**

1 Customer, and Billing Customer functions in the ECOSS that he prepared.

2

3 **Q. Does the Panel agree with Mr. Pollock’s recommended customer**  
 4 **charges?**

5 A. No. Mr. Pollock includes in his proposed customer charges the costs  
 6 associated with Account 930.2 (which consists primarily of Environmental  
 7 Remediation costs) and Account 908 (which consists of Energy Efficiency  
 8 costs), neither of which are normally included in the customer charge.

9 The table below shows the effect of eliminating these costs from the  
 10 customer charge, with the allocated costs taken from Schedules 9, 10, and  
 11 11 of the Company’s original ECOSS, Exhibit \_\_\_ (E-RDP-1).

12

<b>Proposed Customer Charges and Customer Costs</b>			
	<b>SC-3A- Sec/Pri</b>	<b>SC-3A- SubT</b>	<b>SC-3A-T</b>
Customer-classified costs in Company ECOSS	\$2,004,000	\$2,294,000	\$7,645,000
Primary Customer- Acct 930.2	(253,000)	(345,000)	(1,164,000)
Secondary Customer- Acct 930.2	(381,000)	(519,000)	(1,752,000)
Billing Customer- Acct 930.2	(8,000)	(11,000)	(38,000)
Billing Customer- Acct 908EE	(178,000)	(243,000)	(820,000)
Costs in Customer charge	\$1,184,000	\$1,176,000	\$3,871,000
Number of Customer bills- annual	1,127	1,016	1,072
Costs in Customer charge / monthly bills	\$1,051	\$1,157	\$3,611
Company’s Proposed Customer Charges	\$902	\$1,400	\$3,172

13

**Rebuttal Testimony of the Electric Rate Design Panel**

1 The table shows that the Company's proposed customer charges are  
2 reasonably close to the Customer-classified costs normally included in the  
3 customer charge. The Company has proposed keeping customer charges  
4 at their current levels to minimize intraclass revenue shifts.

5

6 **IV. Merchant Function Charge**

7 **Q. Please summarize Staff's recommendations regarding the Merchant**  
8 **Function Charge.**

9 A. The MFC has four components: (1) commodity-related credit and  
10 collections, (2) commodity-related uncollectibles expense, (3) costs  
11 associated with electric supply procurement, and (4) the return  
12 requirement for commodity-related working capital. With two  
13 exceptions, the SERP agrees with the Company's methodology for  
14 calculating these components.

15

16 **Q. Please describe the two changes that the SERP is proposing be made**  
17 **to the Company's methodology for calculating the MFC components.**

18 A. First, the SERP is proposing that the Company use a three year average of  
19 the uncollectible rates to calculate the uncollectibles component of the  
20 MFC, instead of using data for the most recent one year period as was  
21 proposed in the Company's filing. Second, the SERP is proposing that the

**Rebuttal Testimony of the Electric Rate Design Panel**

1 Company use the “Other Customer Capital Rate” instead of the pre-tax  
2 weighted average cost of capital to determine the return requirement on  
3 commodity-related working capital.

4

5 **A. Uncollectibles Expense Component of MFC**

6 **Q. Does the Company agree with Staff’s proposed changes to the**  
7 **uncollectibles expense component of the MFC?**

8 A. No. As discussed in the rebuttal testimony of the Shared Services and  
9 Customer Panel, the Company maintains that its methodology is more  
10 appropriate to calculate the uncollectible rate.

11

12 **Q. If Staff’s recommendation regarding calculation of the uncollectible**  
13 **rate were adopted, are any corrections necessary?**

14 A. Yes. The Company has reviewed Exhibit \_\_\_ (SERP-7 Corrected), Page  
15 3, and determined that Staff has not correctly updated the forecast of  
16 commodity revenue shown on Line 4 to reflect the overall change in  
17 Staff’s sales forecast. In addition, Exhibit\_\_\_ (E-RDP-7), Schedule 1,  
18 Page 3 from the Company’s original filing would need to be updated if  
19 Staff’s revenue forecast and proposed methodology for calculating the  
20 uncollectibles component were adopted because the schedule not only  
21 updates the uncollectible rates used in the MFC calculation (which Staff

**Rebuttal Testimony of the Electric Rate Design Panel**

1 accurately reflects in Exhibit \_\_\_\_ (SERP-7 Corrected), Page 3, Line 3), but  
2 also allocates overall uncollectibles expense in the ECOSS between  
3 delivery and commodity.

4

5 **B. Return on Commodity–Related Working Capital**

6 **Q. Does the Panel agree with Staff’s proposed changes to the working  
7 capital component of the MFC?**

8 A. No. The Company continues to support the use of the pre-tax weighted  
9 average cost of capital to calculate the working capital component of the  
10 MFC. The basis for the Company’s position is set forth in the rebuttal  
11 testimony of the Revenue Requirements Panel.

12

13 **C. Credit and Collections and Supply Procurement Components  
14 of MFC**

15 **Q. Are there other changes that should be made to Staff’s calculation of  
16 the MFC?**

17 A. Yes. Two changes should be made to Staff’s calculation of the credit and  
18 collections component of the MFC shown on Exhibit \_\_\_\_ (SERP-7  
19 Corrected), Page 4 and one change should be made to the supply  
20 procurement component.

21

**Rebuttal Testimony of the Electric Rate Design Panel**

1 **Q. Please explain the two changes to the credit and collections component**  
2 **of the MFC.**

3 A. First, the Company found that the forecast POR kilowatt-hour sales used  
4 to calculate the credit and collections per kilowatt-hour rates for non-  
5 demand, demand and street lighting customers were not updated to reflect  
6 Staff's proposed sales forecast changes. In the Company's original filing,  
7 the forecast POR kilowatt-hours were calculated by applying Historic Test  
8 Year POR ratios to the ESCO sales forecast. The Company proposes that  
9 the POR kilowatt-hour sales should be updated using the same  
10 methodology once the final sales forecast has been determined. Second,  
11 because the Company's credit and collections revenue requirement was  
12 based on the results of the ECOSS in the Company's original filing, it  
13 would need to be revised to reflect the results of the Historic Test Year  
14 ECOSS if the Commission adopts Staff's recommendation that an Historic  
15 Test Year ECOSS be used.

16  
17 **Q. What change to Staff's calculation of the supply procurement**  
18 **component of the MFC does the Company believe is necessary?**

19 A. Similar to the credit and collections component, the supply procurement  
20 revenue requirement was not updated to reflect Staff's Historic Test Year  
21 ECOSS. Thus, the revenue requirement will need to be updated for this

**Rebuttal Testimony of the Electric Rate Design Panel**

1 as well to reflect the Historic Test Year ECOSS, if it is adopted.

2

3 **V. Historic Demand**

4 **Q. Mr. Pollock asserts that the Company should eliminate the use of**  
5 **Historic Demand for all RP and EP customers. Does the Company**  
6 **agree with Mr. Pollock's Exhibit \_\_\_ (JP-5), which purports to show**  
7 **that there would be a minimal change in delivery revenues if Historic**  
8 **Demand were eliminated?**

9 A. No. The example that Mr. Pollock submitted in Exhibit \_\_\_ (JP-5) is  
10 based on only one customer for one month. Even for that one customer,  
11 the annualized impact (assuming the same load for twelve months) that  
12 would have to be collected from other customers through the Company's  
13 Revenue Decoupling Mechanism would be approximately \$653.

14

15 **Q. Would there be additional revenue impacts from the example relied**  
16 **on by Mr. Pollock that are not reflected in his testimony?**

17 Yes. Based on Exhibit \_\_\_ (JP-5), the customer would also experience an  
18 annual reduction of approximately \$969 in the form of reduced  
19 surcharges. This amount would be collected from other customers  
20 through the Company's surcharge reconciliation mechanisms. Thus, if  
21 Historic Demand were eliminated for the customer shown in Exhibit \_\_\_

**Rebuttal Testimony of the Electric Rate Design Panel**

1 (JP-5), the estimated lost revenues that would have to be collected from  
2 other customers would total \$1,622. If Historic Demand were eliminated  
3 for all customers before full standard delivery rates were phased in, the  
4 burden of the lost revenues resulting from the change for all these  
5 customers would be shifted to the Company's other customers. The  
6 Company does not believe that other customers, who are already paying  
7 full standard tariff rates, should bear that burden, particularly given that  
8 the customers who are subject to Historic Demand benefit from RP and EP  
9 delivery discounts and the exemption from surcharges on their RP and/or  
10 EP allocations. In addition, all EP and RP customers will receive  
11 additional benefits effective July 1, 2013, as approved in Case 11-E-0535  
12 and noted in Mr. Pollock's testimony (at 33). The Company does not  
13 support providing the additional benefit suggested by Mr. Pollock at the  
14 expense of other customers.

15

16 **Q. If the Commission were to eliminate Historic Demand for all**  
17 **customers receiving existing EP and/or RP allocations, what other**  
18 **changes would be required?**

19 A. If the Commission eliminated Historic Demand for all customers receiving  
20 RP and EP allocations, the following additional changes would be  
21 required:

**Rebuttal Testimony of the Electric Rate Design Panel**

- 1                   • The sales forecast would need to be reduced by removing
- 2                   the billed Historic Demand kilowatt-hours.
- 3                   • The load factor percentages used to determine the forecast
- 4                   billing demand by service class and voltage delivery levels
- 5                   (“VDL”) would need to be modified.
- 6                   • The forecast retail revenues at current rates for each
- 7                   applicable service class and VDL would need to be
- 8                   decreased.
- 9                   • The forecast billing determinants used as allocators in the
- 10                  ECOSS would need to be modified.
- 11                  • The forecast billing determinants used for rate design
- 12                  would need to be modified.

13

14 **Q. If the Company is not proposing to eliminate Historic Demand for RP**

15 **and EP customers until they are paying full standard tariff rates, why**

16 **did the Company include them in the ECOSS?**

17 A. The elimination of Historic Demand and the decision to include RP and

18 EP customers in the ECOSS are separate issues. EP and RP customers are

19 currently being phased in to full standard tariff rates, and the majority of

20 these customers will pay full standard tariff rates as of January 1, 2016.

21 To properly determine base delivery rates for the applicable service

**Rebuttal Testimony of the Electric Rate Design Panel**

1 classifications for these customers, all costs and revenues forecast at full  
2 standard tariff rates need to be included in the ECOSS. The discounted  
3 delivery rates that are currently billed for EP and RP allocations will be  
4 reconciled through the Company's proposed Replacement and Expansion  
5 discount deferral, which was allocated to all service classifications in the  
6 ECOSS. The same methodology (inclusion in ECOSS at full standard  
7 tariff rates and allocation of the discount to all classes) has been used for  
8 the Company's contract customers and was approved in the 2010 Electric  
9 Rate Case.

10

11 **VI. Revenue Forecast**

12 **A. Corrections to Staff's Revenue Forecast**

13 **Q. Does the Company agree with the forecast revenues at current rates**  
14 **presented in Exhibit \_\_\_\_ (SERP-6 Corrected)?**

15 **A.** No. The Company does not agree with the revenue forecast utilized in the  
16 SERP's testimony. The Company continues to support its total retail  
17 revenues of \$2.278 billion submitted in its Correction and Updates  
18 Testimony, Exhibit \_\_\_\_ (E-RDP-4CU), Schedule 2. Except as discussed  
19 below, the Company's miscellaneous revenues were updated to reflect the  
20 September 2012 Blue Chip Economic Indicators, as discussed in the  
21 Revenue Requirements Panel rebuttal testimony. The changes to

**Rebuttal Testimony of the Electric Rate Design Panel**

1 miscellaneous revenues are shown on Exhibit \_\_\_\_ (RRP-11R).

2

3 **Q. Does the Company agree with the sales forecast used by Staff to**  
4 **calculate the forecast revenues at current rates presented in Exhibit**  
5 **\_\_\_\_ (SERP-6 Corrected)?**

6 A. No. The Company supports the electric sales forecast filed in its  
7 Corrections and Updates Testimony and shown in Exhibit \_\_\_\_ (JFG-  
8 13CU), as discussed in Company Witness Joseph F. Gredder's rebuttal  
9 testimony.

10

11 **B. Late Payment Charge Revenue**

12 **Q. Did Staff recommend any changes to the Company's forecast of Late**  
13 **Payment Charge revenue?**

14 A. The Staff Gas Rates Panel recommended that the late payment charge  
15 ("LPC") revenue included in the Company's gas operating revenue  
16 forecast be adjusted. However, a similar adjustment to the Company's  
17 electric operating revenue forecast was not discussed in the testimony filed  
18 by the SERP.

19

20 **Q. Does the Company agree with Staff's proposed adjustments to gas**  
21 **LPC revenue?**

**Rebuttal Testimony of the Electric Rate Design Panel**

1 A. The Company agrees that an adjustment should be made, but does not  
2 agree with the methodology proposed by the Staff Gas Rates Panel. As  
3 described in the rebuttal testimony of the Company's Gas Rate Design  
4 Panel, LPC revenues should be increased proportionate to the Company's  
5 requested Rate Year revenue increase. In the Gas Rate Design Panel's  
6 rebuttal testimony, the Company is proposing the following calculation to  
7 adjust gas late payment revenues to reflect the Company's requested Rate  
8 Year revenue increase:

9  
10 
$$\text{LPC Revenue} = \text{Rate Year Revenue Increase} \times \text{LPC \%} / (1 + \text{LPC \%})$$

11 
$$\text{LPC \%} = \text{LPC percentage for Historic Test Year}$$

12  
13 The increase in forecast Rate Year LPC revenues would then  
14 correspondingly reduce the requested increase to Rate Year delivery  
15 revenues to determine the associated increase to delivery rates.

16  
17 **Q. In its initial filing, did the Company make a similar adjustment to**  
18 **electric LPC revenue in the electric operating revenue forecast?**

19 A. No. Upon review of Staff's proposed adjustment to gas LPC revenue, the  
20 Company realized that a similar adjustment should have been, but was not,  
21 made to electric LPC revenue. The Company believes that a portion of the

**Rebuttal Testimony of the Electric Rate Design Panel**

1 Company's requested base rate increase should be allocated to LPC  
2 revenue based on a calculation similar to the one proposed by the Gas  
3 Rate Design Panel in its rebuttal testimony. The Historic Test Year LPC  
4 percentage for electric revenues is presented in Exhibit \_\_\_ (E-RDP-4),  
5 Schedule 5, Page 7.  
6

7 **VII. Surcharge to Recover RSS Costs**

8 **Q. In the rebuttal testimony of the EIOP, the Company proposes**  
9 **offsetting certain deferred RSS costs with deferred liabilities and**  
10 **implementing a surcharge beginning April 1, 2013 to recover any**  
11 **ongoing RSS costs. Please explain how the surcharge would be**  
12 **calculated and collected from customers.**

13 A. As discussed in the EIOP's rebuttal testimony, the Company proposes to  
14 defer RSS costs incurred from September 1, 2012 through March 31, 2013  
15 and to offset those deferred costs with deferred liabilities. The Company  
16 proposes to recover all RSS costs remaining to be reconciled as of April 1,  
17 2013 and all costs incurred on or after that date through a separate  
18 surcharge mechanism to address RSS costs from the mothballing of the  
19 Dunkirk units, as well as other RSS costs that arise prospectively. The  
20 Company proposes to calculate the surcharge on a forecast basis and  
21 assess it to customers on a current basis with an annual reconciliation

**Rebuttal Testimony of the Electric Rate Design Panel**

1 including interest at the Other Customer Deposit Rate. The RSS costs will  
2 be allocated to service classifications based on the most recent  
3 transmission plant allocator and assessed on a volumetric basis, per kWh  
4 for non-demand service classifications and per kW for demand service  
5 classifications. The RSS surcharge will be applicable to all customers  
6 with the exception of those customers whose rates are developed using  
7 marginal costs (Empire Zone qualifying load and Excelsior Jobs Program  
8 qualifying load). The Company's tariff leaf enumerating the mechanics of  
9 the surcharge is provided as Exhibit \_\_\_\_ (E-RDP-3R).

10

11 **VIII. Conclusion**

12 **Q. Does that conclude the Panel's rebuttal testimony?**

13 A. Yes, it does.

Exhibits of  
Electric Rate Design Panel

**Rebuttal Testimony of the Electric Rate Design Panel**

**List of Exhibits**

- Exhibit \_\_\_ (E-RDP-1R) Staff-Requested Historic Test Year ECOSS in Response to Information Request DPS-338 (LAR-4), With Minor Corrections
- Exhibit \_\_\_ (E-RDP-2R) Company's Narrative Response and Attachment 2 to Information Request MI-125 (MM-125)
- Exhibit \_\_\_ (E-RDP-3R) Proposed Tariff Leaf on RSS Surcharge



**Rebuttal Testimony of the Electric Rate Design Panel**

Exhibit \_\_\_\_ (E-RDP-1R)

Staff-Requested Historic Test Year ECOSS in Response to Information Request  
DPS-338 (LAR-4), With Minor Corrections

Niagara Mohawk Power Corporation d/b/a National Grid  
Class Cost of Service Study (\$000s)  
Historic Year 2011 (LAR-4 Supplemental 2)  
**Summary of Results**

Sum  
E-RDP-IR, Sch. 1  
Tot  
Summary

Line	Account	Balance	Residential TOU	Resid. TOU	Small Gen No Dem	Small Gen Demand	Large Gen-Sec	Large Gen-Pri	Large Gen-Tran	Large Gen TOU-S/P	Ige Gen TOU-SubT	Ige Gen TOU-Tran	Lighting
1	Distribution revenue	1,290,144	765,855	13,115	57,579	168,154	117,972	41,585	5,192	23,026	12,867	34,887	49,911
2	Forfeited discounts	15,692	11,397	119	726	2,093	852	300	37	54	30	82	0
3	Other revenue	52,187	15,368	279	1,392	7,247	9,710	3,916	791	2,664	3,494	8,691	(1,362)
4	Total Revenue	1,358,023	792,619	13,513	59,697	177,494	128,534	45,801	6,020	25,744	16,391	43,660	48,550
5													
6	Expenses	1,196,477	724,037	10,283	49,188	149,367	105,252	36,084	5,668	21,650	14,474	43,332	37,143
7	Net income	161,546	68,582	3,230	10,509	28,127	23,282	9,718	352	4,094	1,917	328	11,407
8													
9	Rate Base	3,571,007	2,090,638	32,969	143,978	461,671	355,466	107,137	17,996	67,936	44,094	132,609	116,514
10													
11	Return on Rate Base	4.5238%	3.28%	9.80%	7.30%	6.09%	6.55%	9.07%	1.96%	6.03%	4.35%	0.25%	9.79%
12	Relative Return	1.00	0.73	2.17	1.61	1.35	1.45	2.01	0.43	1.33	0.96	0.05	2.16
13	Revenue Requirement	1,541,643	933,864	12,882	61,753	191,811	137,422	44,785	7,600	27,947	18,832	58,431	46,317
14													
15	Operating expenses	792,647	488,911	6,184	31,893	98,046	64,631	22,852	4,076	14,012	9,913	31,472	20,657
16	Uncollectibles- Delivery	17,246	15,556	9	351	775	332	117	15	8	4	12	68
17	Depreciation expense	167,767	100,402	1,471	6,993	20,983	15,683	4,651	796	2,971	1,876	5,723	6,218
18	General tax / Other	154,090	89,032	1,434	5,989	19,013	15,972	4,867	648	3,158	1,977	6,001	5,999
19	GRT	0	0	0	0	0	0	0	0	0	0	0	0
20													
21	Pre-tax income	1,131,750	693,901	9,097	45,226	138,816	96,619	32,487	5,534	20,149	13,770	43,208	32,943
22	Income taxes	409,893	239,963	3,785	16,527	52,995	40,803	12,298	2,066	7,798	5,062	15,223	13,374
23	Net income	146,353	85,674	1,352	5,901	18,923	14,570	4,391	738	2,784	1,807	5,437	4,775
24													
25	Return on Rate Base	7.38%	7.38%	7.38%	7.38%	7.38%	7.38%	7.38%	7.38%	7.38%	7.38%	7.38%	7.38%
26	Revenue increase (decrease)	183,620	140,888	(662)	2,011	13,933	8,666	(798)	1,635	2,304	2,528	15,359	(2,243)
27	Revenue increase (decrease) %	13.52%	17.82%	(4.7%)	3.44%	8.1%	6.91%	(2.2%)	26.2%	8.6%	14.9%	33.8%	(4.6%)
28	Relative incr (decr)	1.00	1.32	(0.35)	0.25	0.60	0.51	(0.16)	1.94	0.63	1.10	2.50	(0.34)
29													
30	Return- LAR-4 Supplemental 2	4.52%	3.28%	9.80%	7.30%	6.09%	6.55%	9.07%	1.96%	6.03%	4.35%	0.25%	9.79%
31	Return- LAR-4	4.68%	3.41%	10.28%	7.54%	6.34%	6.73%	9.16%	1.90%	6.06%	4.36%	0.10%	9.96%
32	As Filed	5.4475%	4.63%	9.61%	9.09%	6.31%	6.21%	6.92%	5.00%	4.60%	5.26%	3.29%	10.35%
33													
34	Rel. Ret.- LAR-4 Supplemental 2	1.00	0.73	2.17	1.61	1.35	1.45	2.01	0.43	1.33	0.96	0.05	2.16
35	Rel. Ret.- LAR-4	1.00	0.73	2.20	1.61	1.36	1.44	1.96	0.41	1.30	0.93	0.02	2.13
36	Relative Return-As Filed	1.00	0.85	1.76	1.67	1.16	1.14	1.27	0.92	0.85	0.97	0.60	1.90



**Case 12-E-0201**

**Rebuttal Testimony of the Electric Rate Design Panel**

Exhibit \_\_\_\_ (E-RDP-2R)

Company's Narrative Response and Attachment 2 to Information Request MI-125  
(MM-125)

Date of Request: September 20, 2012  
Due Date: September 30, 2012

Multiple Intervenors Request No. 125  
NMPC Req. No. 796

NIAGARA MOHAWK POWER CORPORATION d/b/a National Grid

Case 12-E-0201 and 12-G-0202 – Niagara Mohawk Power Corporation d/b/a National Grid

Request For Information

FROM: Multiple Intervenors

TO: Electric Rate Design Panel

Request: In reference to Niagara Mohawk's Corrections and Updates Cost of Service Study, provide a copy of the demand allocation corrected study.

Response:

The Company has become aware of an error relating to the computation of the Demand allocators in the Rate Year Embedded Cost of Service Study submitted with the Corrections and Updates testimony of the Electric Rate Design Panel (ECOSS CU). This response presents the ECOSS CU (Corrected), which corrects the ECOSS CU for that error.

In computing the load factors used in computing the Demand allocators used in the ECOSS CU (and the original ECOSS), the MWh should have reflected measurements taken at the meter. In the ECOSS CU (and the original ECOSS), the MWh for the year ended November 30, 2011 instead reflected measurements at the generator. The ECOSS CU (Corrected) uses Demand allocators calculated based on load factors with all MWh correctly measured at the meter.

The ECOSS CU (Corrected) is provided in Attachment 1 to this response (the file named *NiMo-E 2012 ACOS (MI-125)Attach 1.xlsm*). Attachment 2 (the file named *NiMo-E 2012 ACOS (MI-125) Attach 2.pdf*) presents a summary of the ECOSS CU (Corrected) (page 1), and the corrected calculation of the Demand allocators (pages 2-3).

As shown on Attachment 2, page 1, the ECOSS CU (Corrected) class rates of return (line 32) do not vary substantially from the ECOSS CU rates (line 33). Similarly, the ECOSS CU (Corrected) relative rates of return (line 34) do not vary substantially from the original relative rates (line 35). (Of the eleven classes listed, nine had a change of 3 basis points or less, one changed by 5 basis points and one changed by 9 basis points.) Also, the required revenue increases and decreases in the ECOSS CU (Corrected) (line 37) do not vary substantially from the original revenue increases and decreases (line 38).

Name of Respondent:  
Howard Gorman

Date of Reply:  
September 21, 2012

Rate Year 2014 (E-COSS CU Corrected)  
**Summary of Results**

Line	Account	Balance	Residential	Resid. TOU	Small Gen No Dem	Small Gen Demand	Large Gen Sec	Large Gen Pri	Large Gen Tran	Lge Gen TOU-S/P	Lge Gen TOU-SubT	Lge Gen TOU-Tran	Lighting
1	Distribution revenue	1,276,766	751,141	12,625	59,522	166,574	115,394	39,184	5,597	24,124	13,803	38,980	49,823
2	Forfeited discounts	11,930	8,664	91	552	1,592	667	217	20	72	21	34	0
3	Other revenue	130,876	67,547	1,774	4,039	16,318	14,317	5,467	1,347	3,369	4,142	12,757	(203)
4	Total Revenue	1,419,572	827,352	14,490	64,112	184,484	130,378	44,868	6,964	27,565	17,967	51,771	49,620
5													
6	Expenses	1,203,738	721,307	10,857	50,006	150,963	106,456	36,340	5,955	23,404	15,317	46,606	36,526
7	Net income	215,834	106,045	3,633	14,106	33,521	23,922	8,528	1,009	4,161	2,650	5,165	13,094
8													
9	Rate Base	3,962,086	2,298,399	38,077	156,079	535,654	387,881	121,282	19,525	88,389	49,180	147,104	120,516
10													
11	Return on Rate Base	5.4475%	4.61%	9.54%	9.04%	6.26%	6.17%	7.03%	5.17%	4.71%	5.39%	3.51%	10.87%
12	Relative Return	1.00	0.85	1.75	1.66	1.15	1.13	1.29	0.95	0.86	0.99	0.64	1.99
13	Revenue Requirement	1,548,032	930,096	13,457	61,042	195,427	138,790	45,984	7,669	31,340	19,584	60,597	44,047
14													
15	Operating expenses	733,143	450,747	5,868	29,488	88,640	61,055	21,730	3,856	13,589	9,717	30,855	17,598
16	Uncollectibles- Delivery	20,477	18,471	10	416	920	424	138	13	2	1	1	81
17	Depreciation expense	179,362	105,877	1,652	7,225	23,649	16,415	5,035	871	3,789	2,083	6,356	6,408
18	General tax / Other	176,295	100,483	1,710	6,628	22,900	17,942	5,650	766	4,170	2,336	7,094	6,614
19	GRT	0	0	0	0	0	0	0	0	0	0	0	0
20													
21	Pre-tax income	1,109,277	675,578	9,240	43,758	136,109	95,837	32,553	5,507	21,551	14,137	44,306	30,701
22	Income taxes	438,755	254,518	4,217	17,284	59,318	42,954	13,431	2,162	9,788	5,446	16,291	13,346
23	Net income	146,353	84,896	1,407	5,765	19,787	14,328	4,480	721	3,265	1,817	5,435	4,452
24													
25	Return on Rate Base	7.38%	7.38%	7.38%	7.38%	7.38%	7.38%	7.38%	7.38%	7.38%	7.38%	7.38%	7.38%
26													
27	Revenue increase (decrease)	128,460	102,743	(1,033)	(3,070)	10,943	8,412	1,116	704	3,774	1,617	8,826	(5,573)
28	Revenue increase (decrease) %	9.05%	12.4%	(7.1%)	(4.8%)	5.9%	6.5%	2.5%	10.1%	13.7%	9.0%	17.0%	(11.2%)
29	Relative incr (decr)	1.00	1.37	(0.79)	(0.53)	0.66	0.71	0.27	1.12	1.51	0.99	1.88	(1.24)
30	Tax rate	33.36%	33.36%	33.36%	33.36%	33.36%	33.36%	33.36%	33.36%	33.36%	33.36%	33.36%	33.36%
31													
32	Return- E-COSS CU (Corrected)	5.45%	4.61%	9.54%	9.04%	6.26%	6.17%	7.03%	5.17%	4.71%	5.39%	3.51%	10.87%
33	As Filed	5.4475%	4.63%	9.61%	9.09%	6.31%	6.21%	6.92%	5.00%	4.60%	5.26%	3.29%	10.35%
34	Relative Return- E-COSS CU (Corrected)	1.00	0.85	1.75	1.66	1.15	1.13	1.29	0.95	0.86	0.99	0.64	1.99
35	Relative Return-As Filed	1.00	0.85	1.76	1.67	1.16	1.14	1.27	0.92	0.85	0.97	0.60	1.90
36													
37	Revenue incr. (decr.)- E-COSS CU (Corrected)	9.05%	12.4%	(7.1%)	(4.8%)	5.9%	6.5%	2.5%	10.1%	13.7%	9.0%	17.0%	(11.2%)
38	As Filed	9.05%	12.3%	(7.4%)	(4.9%)	5.7%	6.2%	2.9%	10.9%	14.2%	9.6%	18.3%	(9.9%)

**Demand Allocators (Corrected)**

Line	Rate Class	12 Months Ended 8/31/2009			12 Months Ended 9/30/2010			12 Months Ended 11/30/2011		
		Historical MWh	Historical Class NCP	Load Factor at NCP	Historical MWh	Historical Class NCP	Load Factor at NCP	Test Year MWh	Test Year Class NCP	Load Factor at NCP
1	Residential	10,746,052	2,698	45.5%	11,182,773	3,156	40.4%	11,351,122	3,248	39.9%
2	Residential TOU	370,144	87	48.4%	362,282	81	51.1%	355,189	71	57.0%
3	Small Gen No Dem	643,234	173	42.4%	630,038	184	39.0%	641,783	192	38.2%
4	Small Gen Demand	4,347,815	1,054	47.1%	4,388,525	1,046	47.9%	4,345,301	985	50.3%
5	Large Gen-Sec	4,359,267	1,036	48.0%	4,392,942	915	54.8%	4,389,340	968	51.7%
6	Large Gen-Pri	2,202,027	385	65.4%	2,208,536	400	63.0%	2,184,794	383	65.2%
7	Large Gen-Tran	1,343,654	226	67.9%	1,241,274	193	73.5%	1,253,565	199	71.7%
8	Large Gen TOU-S/P	1,452,258	252	65.7%	1,343,003	235	65.1%	1,296,851	215	69.0%
9	Large Gen TOU-SubT	1,823,335	287	72.6%	1,788,987	297	68.9%	1,785,568	291	70.0%
10	Large Gen TOU-Tran	5,532,299	870	72.6%	5,636,865	816	78.9%	6,000,772	1,130	60.6%
11	Lighting	207,019	57	41.8%	206,907	67	35.5%	202,712	57	40.6%
12	System	33,027,103	7,125	52.9%	33,382,132	7,390	51.6%	33,806,998	7,739	49.9%
13	Check=							33,806,998		7,740
14										
15										
16										
17	Residential	10,746,052	2,374	51.7%	11,182,773	2,942	43.4%	11,351,122	3,093	41.9%
18	Residential TOU	370,144	60	69.9%	362,282	67	61.5%	355,189	71	57.0%
19	Small Gen No Dem	643,234	173	42.4%	630,038	181	39.7%	641,783	173	42.4%
20	Small Gen Demand	4,347,815	917	54.1%	4,388,525	1,001	50.1%	4,345,301	935	53.1%
21	Large Gen-Sec	4,359,267	940	53.0%	4,392,942	810	61.9%	4,389,340	857	58.5%
22	Large Gen-Pri	2,202,027	369	68.1%	2,208,536	367	68.7%	2,184,794	344	72.5%
23	Large Gen-Tran	1,343,654	174	88.1%	1,241,274	175	80.8%	1,253,565	181	79.3%
24	Large Gen TOU-S/P	1,452,258	222	74.8%	1,343,003	222	69.2%	1,296,851	205	72.3%
25	Large Gen TOU-SubT	1,823,335	237	87.8%	1,788,987	270	75.6%	1,785,568	276	73.9%
26	Large Gen TOU-Tran	5,532,299	719	87.8%	5,636,865	685	94.0%	6,000,772	764	89.7%
27	Lighting	207,019	2	1494.3%	206,907	2	1520.1%	202,712	1	1693.3%
28	System	33,027,103	6,187	60.9%	33,382,132	6,722	56.7%	33,806,998	6,898	55.9%
29	Check=									6,898

**Demand Allocators (Corrected)**

<b>Line</b>	<b>Rate Class</b>	<b>Average Load Factor for NCP</b>	<b>Rate Year MWh</b>
1	Residential	41.9%	11,113,209
2	Residential TOU	52.2%	356,715
3	Small Gen No Dem	39.9%	636,380
4	Small Gen Demand	48.4%	4,361,234
5	Large Gen-Sec	51.5%	4,306,197
6	Large Gen-Pri	64.5%	2,017,640
7	Large Gen-Tran	71.0%	600,370
8	Large Gen TOU-S/P	66.6%	1,304,104
9	Large Gen TOU-SubT	70.5%	1,809,462
10	Large Gen TOU-Tran	70.7%	6,258,306
11	Lighting	39.3%	203,195
12	System		
13	Check=		32,966,811

<b>Line</b>	<b>Rate Class</b>	<b>Average Load Factor for ICP</b>	<b>Rate Year MWh</b>
16			
17	Residential	45.7%	11,113,209
18	Residential TOU	62.8%	356,715
19	Small Gen No Dem	41.5%	636,380
20	Small Gen Demand	52.4%	4,361,234
21	Large Gen-Sec	57.8%	4,306,197
22	Large Gen-Pri	69.8%	2,017,640
23	Large Gen-Tran	82.7%	600,370
24	Large Gen TOU-S/P	72.1%	1,304,104
25	Large Gen TOU-SubT	79.1%	1,809,462
26	Large Gen TOU-Tran	90.5%	6,258,306
27	Lighting	1569.2%	203,195
28	System	56.3%	
29	Check=		32,966,811

<b>Rate Year Class Transmission</b>	<b>Rate Year Class Primary</b>	<b>Rate Year Class Secondary</b>
3,025	3,025	3,025
78	78	78
182	182	182
1,028	1,028	1,006 a
954	954	954
357	357	
96		
224	224	40 b
293		
1,010		
59	59	59
7,307	5,907	5,345

(a) 97.9% of load is served at Secondary voltages

(b) 18.1% of load is served at Secondary voltages

<b>Rate Year ICP-Transmission</b>
2,779
65
175
950
851
330
83
207
261
789
1
6,491



**Rebuttal Testimony of the Electric Rate Design Panel**

Exhibit \_\_\_\_ (E-RDP-3R)

Proposed Tariff Leaf for RSS Surcharge

PSC NO: 220 ELECTRICITY  
NIAGARA MOHAWK POWER CORPORATION  
INITIAL EFFECTIVE DATE:

LEAF:  
REVISION:  
SUPERSEDING REVISION:

## “DRAFT”

### GENERAL INFORMATION

#### 50. RELIABILITY SUPPORT SERVICES (RSS) SURCHARGE

50.1 The RSS surcharge provides for recovery from customers of costs incurred by the Company, and approved by the Commission, for third-party services to ensure that local reliability needs are met. RSS costs may include both fixed and variable third-party charges. Fixed and estimated variable charges will be included in the RSS surcharge and subsequently reconciled as provided in Rule 50.2.2.3.

50.1.1 The RSS surcharge is applicable to all customers taking service under P.S.C. No. 220 and 214 Electricity, regardless of supplier, including Replacement and Expansion Power, Recharge New York Power, High Load Factor Power, Preservation Power, and customers taking service under S.C. No.12 in accordance with the terms of their individual contracts.

50.1.1.1 Empire Zone qualifying load and Excelsior Jobs Program qualifying load are not subject to this surcharge.

50.2 The recovery of RSS costs shall be allocated to service classifications based on the most recent transmission plant allocator.

50.2.1 RSS costs incurred on or after April 1, 2013 (including any reconciled amounts from prior periods) will be assessed on a forecast basis and recovered from customers on a current basis.

50.2.2 The RSS surcharge will be applied to customers on a sales forecast basis.

50.2.2.1 The RSS surcharge will be collected from customers on a volumetric basis, per kWh for non-demand service classifications and per kW for demand service classifications.

50.2.2.2 The RSS surcharge shall be determined by dividing the amount of RSS costs incurred by the Company for each service classification as determined in Rule 50.2 above by the forecast sales or demand for that service classification

50.2.2.3 The RSS surcharge collected from customers will be subject to an annual reconciliation for any over or under collections from the previous year. The RSS reconciliation over or under collections will be credited or surcharged to customers, which will include interest at the applicable other customer deposit rate.

50.3 The RSS surcharge shall be shown on statements filed with the Public Service Commission apart from this rate schedule not less than fifteen (15) business days before its effective date.



**Before the Public Service Commission**

**NIAGARA MOHAWK POWER CORPORATION d/b/a NATIONAL GRID**

**Rebuttal Testimony**

**of the**

**Electric Infrastructure and Operations Panel**

**Case 12-E-0201**

Rebuttal Testimony of the Electric Infrastructure and Operations Panel

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**Rebuttal Testimony of the Electric Infrastructure and Operations Panel**

1 **I. Introduction**

2 **Q. Please identify the members of the Electric Infrastructure and**  
3 **Operations Panel.**

4 A. The Panel consists of Ellen S. Smith, Keith P. McAfee and Allen C.  
5 Chieco.

6  
7 **Q. Is this the Panel that testified previously in this proceeding?**

8 A. Yes. The Electric Infrastructure and Operations Panel (“EIOP”) provided  
9 testimony as part of the Company’s April 27, 2012 and July 16, 2012  
10 filings.

11

12 **Q. What is the purpose of the Panel’s testimony?**

13 A. The Panel responds to certain issues raised in the testimony of the Staff  
14 Electric Infrastructure Panel, Staff Vegetation Management Panel, and  
15 Staff Reliability Performance Mechanism Panel regarding the Company’s  
16 electric infrastructure and operations plans.

17

18 **Q. Does the Panel sponsor any exhibits?**

19 A. Yes. The Panel sponsors the following exhibits:

- 20 • Exhibit \_\_ (EIOP-1R): Transmission Capital Plan – Revised  
21 • Exhibit \_\_ (EIOP-2R): Distribution Capital Plan – Revised

**Rebuttal Testimony of the Electric Infrastructure and Operations Panel**

- 1 • Exhibit \_\_ (EIOP-3R): Mid-span mowing table of planned sites
- 2 • Exhibit \_\_ (EIOP-4R): Copy of Response to IR DPS-449 (CVB-1)
- 3 • Exhibit \_\_ (EIOP-5R): I&M Repair Performance CY2009-Aug.
- 4 31, 2012

5

6 **Q. Has the Company revised the funding levels for its proposed capital**  
7 **investment and operations plans?**

8 A. Yes. The Company accepts several of Staff's proposed capital  
9 adjustments, resulting in changes to the Company's transmission and  
10 distribution capital plans. These adjustments are reflected in Exhibit \_\_  
11 (EIOP-1R), which updates Exhibit \_\_ (EIOP-5CU and represents the  
12 Company's revised transmission capital plan, and Exhibit \_\_ (EIOP-2R),  
13 which updates Exhibit \_\_ (EIOP-9) and represents the Company's revised  
14 distribution capital plan. For the most part, the Company does not accept  
15 Staff's proposed adjustments to its operations and maintenance programs.

16

17 **Q. How is the remainder of the Panel's testimony structured?**

18 A. In Section II, the Panel addresses Staff's recommendations regarding the  
19 Company's electric infrastructure investment plan. In Section III, the  
20 Panel addresses recommendations regarding the Company's proposed  
21 operations and maintenance programs, other than vegetation management.

**Rebuttal Testimony of the Electric Infrastructure and Operations Panel**

1           In Section IV, the Panel addresses Staff’s recommendations regarding the  
2           vegetation management programs. In Section V, the Panel responds to  
3           Staff’s recommendation for a new performance metric for inspection and  
4           maintenance program repairs and changes to the existing estimating  
5           performance metric. In Section VI, the Panel addresses allocation of costs  
6           associated with distribution load dispatch and the primary and secondary  
7           distribution systems.

8

9   **II.   Capital Investment Plan**

10           **Transmission Capital Expenditure Reporting**

11   **Q.   Please address Staff’s recommendation that the Company file a report**  
12           **describing reasons for underspending in years where spending is**  
13           **more than five percent below the annual transmission budget.**

14   A.   The Company currently submits several periodic reports relating to its  
15           electric infrastructure planning and investment. The Company’s quarterly  
16           investment plan report includes, among other things, information  
17           regarding actual investment, performance against budget, and details about  
18           individual program and project implementation. The Company proposes  
19           to meet with Staff to determine what different or additional information  
20           would be useful to include in these reports.

21

**Rebuttal Testimony of the Electric Infrastructure and Operations Panel**

1           **Relay Replacement Strategy**

2   **Q.    Does the Company accept Staff's recommendation to reduce the**  
3           **Relay Replacement Strategy in FY16?**

4    A.    Yes. Staff's testimony acknowledges that the Relay Replacement Strategy  
5           is important to maintaining and improving transmission system reliability,  
6           but recommends a reduction of \$4.739 million in the program in FY16.  
7           The reduction proposed by Staff will extend the timing of the program,  
8           thereby delaying the reliability benefits. Nevertheless, the remaining  
9           program funding allows for meaningful progress for the benefit of  
10          customers and the Company therefore accepts the adjustment.

11

12           **Transmission Transformer Replacement Strategy**

13   **Q.    Does the Company agree with Staff's recommendation regarding**  
14           **spare transformers as part of the Transformer Replacement**  
15           **Strategy?**

16    A.    Yes. Maintaining an appropriate number of spares for long lead-time  
17           items such as transformers is a reasonable management tool that benefits  
18           customers. The Company agrees to perform the analysis recommended by  
19           Staff and to evaluate the results to determine whether adjustments to the  
20           Company's approach are appropriate.

21

**Rebuttal Testimony of the Electric Infrastructure and Operations Panel**

1           **Other Damage/Failure Strategy**

2   **Q.    Does the Company agree with Staff’s proposed adjustments to the**  
3           **Other Damage/ Failure Strategy?**

4    A.    Yes. Staff’s adjustments are based on historic information using three-  
5           year average expenditures to arrive at consistent annual spending for FY14  
6           through FY17. Staff’s proposed funding levels are reasonable and the  
7           Company accepts Staff’s proposed downward adjustments of \$2.9 million  
8           in FY14 and \$0.1 million in FY15.

9

10           **Conductor Clearance Strategy**

11   **Q.    Does the Company agree with Staff’s adjustments to the Conductor**  
12           **Clearance strategy?**

13   A.    No. Staff recommends that the Conductor Clearance strategy be reduced  
14           in FY15 and FY16 on the grounds that “there is no specific timeline  
15           established for FERC’s approval of the proposed [bulk electric system  
16           (“BES”)] definition . . . .” (Staff EIP at 31). However, the Company’s  
17           Conductor Clearance strategy is not driven by the proposed changes to the  
18           BES definition, but by compliance with existing safety standards and  
19           Staff’s adjustments would inappropriately defer compliance.

20

21           Specifically, the Conductor Clearance strategy is necessary to restore

**Rebuttal Testimony of the Electric Infrastructure and Operations Panel**

1 ground clearances for overhead conductor spans to comply with the  
2 National Electrical Safety Code (“NESC”) standards, consistent with the  
3 Commission’s Safety Orders in Case 04-M-0159. The Company will  
4 verify existing line clearance on over 300 lines and proposes to perform  
5 the work under an eight-year implementation schedule that ramps up  
6 through FY14 and continues at approximately \$15 million per year for the  
7 period FY15 - FY21. The Company’s eight-year program schedule was  
8 developed to meet existing NESC requirements across the entire  
9 transmission system, not the pending changes regarding the definition of  
10 the BES. Indeed, absent a waiver or exception, the Company estimates  
11 that the work scheduled under its eight-year plan to meet the NESC  
12 standards could be required to be completed within just two or three years  
13 if the FERC adopts the definitional changes to the BES, which would  
14 significantly increase program costs in those years. If FERC rejects or  
15 extends the anticipated timeline for the proposed BES definition change, it  
16 would still be necessary for the Company to move forward to address  
17 clearance issues to meet the NESC standards. Accordingly, no adjustment  
18 to the Conductor Clearance Strategy is warranted.

19

20 **Interconnection Meter Investment Program**

21 **Q. Does the Company agree with Staff’s adjustments to the**

**Rebuttal Testimony of the Electric Infrastructure and Operations Panel**

1 **Interconnection Meter Investment Program?**

2 A. Yes. The calculation methodology proposed by Staff produces a  
3 reasonable result and the Company accepts the \$1.8 million downward  
4 adjustment for FY14.

5

6 **Other System Capacity and Performance (Overdutied Breaker**  
7 **Program)**

8 **Q. Does the Company agree with Staff’s adjustments relating to the**  
9 **Overdutied Breaker Program?**

10 A. Yes. Staff’s adjustment to Project CNYPL26 (to replace overdutied  
11 115kV breakers in the Central and Mohawk regions) is consistent with the  
12 Company’s updated project estimate, which was completed during  
13 preliminary engineering (Step 2A in the End to End (“E2E”) Project  
14 Management Process). Changes in project estimates are expected as  
15 projects mature through the E2E process. Generally, the Company does  
16 not adjust its overall budget levels to correspond to every fluctuation of an  
17 individual project estimate. Rather, the Company manages its overall  
18 capital investment plan to accommodate minor project or program-specific  
19 differences within overall budget levels. Nevertheless, in this instance, the  
20 Company accepts Staff’s adjustment of \$5.4 million over four fiscal years  
21 (FY14 – FY17).

**Rebuttal Testimony of the Electric Infrastructure and Operations Panel**

1            **Southwest NY Reliability Criteria Compliance Program**

2    **Q.    Please summarize Staff’s comments regarding NRG’s mothballing of**  
3            **the Dunkirk plant.**

4    A.    Staff calls for additional system studies; generally supports  
5            implementation of certain capital projects proposed by the Company;  
6            opposes a deferral of capital-related costs and proposes to include costs in  
7            base rates to the extent known; and opposes creating a recovery surcharge  
8            for the costs of the Reliability Support Services (“RSS”) agreement with  
9            Dunkirk to the extent such costs could be recovered from an existing  
10           customer credit balance.

11

12   **Q.    What is the Company’s position regarding Staff’s recommendation to**  
13           **perform additional system studies?**

14   A.    Staff requests that the Company perform a reliability comparison of the  
15           amount of load at risk of being shed, the duration of that risk, and the  
16           probability of contingencies that contribute to that risk under two cases:  
17           one with Dunkirk available and one with Dunkirk unavailable, but  
18           assuming that the Company’s proposed June 2013 transmission  
19           reinforcements are in place. The transmission system in western and  
20           southwestern New York is susceptible to a number of voltage and loading  
21           issues in various seasons under a multitude of system conditions and

**Rebuttal Testimony of the Electric Infrastructure and Operations Panel**

1 contingencies. The broad scope of the requested analyses cannot be  
2 performed within a reasonable timeframe. The Company proposes to  
3 meet with Staff to discuss results of the analyses performed to date, as  
4 well as results of analyses currently being conducted, to determine  
5 whether other beneficial studies that could be performed in a reasonable  
6 timeframe should be done.

7

8 **Q. Does the Company agree with Staff's position regarding the Warren –**  
9 **Falconer #171 line project?**

10 A. Yes. The Company maintains that the preferred alternative to addressing  
11 the reliability concerns on the Warren-Falconer #171 line is to reductor  
12 the line. The Company, however, agrees with Staff that substantial  
13 investment should not be made until First Energy commits to invest on its  
14 portion of the line. If such commitments are not forthcoming, the  
15 Company will pursue alternatives to reductoring the line.

16

17 **Q. Does the Company agree with Staff's position on the recovery of costs**  
18 **associated with the Southwest NY Reliability Criteria Compliance**  
19 **Program for projects due for completion by June 2013?**

20 A. The Company agrees in principle with Staff's recommendation. However,  
21 the cost adjustments reflected in Exhibit \_\_ (EIP-2) in the Reliability

**Rebuttal Testimony of the Electric Infrastructure and Operations Panel**

1 Criteria Compliance Program do not match the description in Staff's  
2 testimony. In its testimony, Staff recommends that the capital  
3 expenditures related to the Southwest projects that are due to be completed  
4 by June 2013 be reflected in the Company's capital plan and that the  
5 associated revenue requirement be reflected in base rates instead of  
6 deferred for future recovery. The analysis performed by Staff accelerates  
7 the in-service date for the Homer Hill Capacitor Banks under project  
8 C31457 to June 2013. In addition, Staff recommends including the  
9 following projects in the capital investment plan with in-service dates of  
10 June 2013:

- 11 • Packard Install 2<sup>nd</sup> Bus Tie - C43736
- 12 • Huntley 2<sup>nd</sup> Bus Tie - C43737
- 13 • Dunkirk Install Mobile Capacitor Banks - C43738
- 14 • Bennett Road Supply Change - C43739
- 15 • Station 39 Supply Change - C43740
- 16 • Station 55 Supply Change - C43741

17 However, Staff's recommended cost adjustments reflected in Exhibit \_\_  
18 (EIP-2) omit funding for the Gardenville capacitor banks under project  
19 C43735. Project C43735 is one of the projects needed by June 2013 to  
20 address the reliability issues resulting from the mothballing of the Dunkirk  
21 plant. Under project C43735, the Company will purchase and install four

**Rebuttal Testimony of the Electric Infrastructure and Operations Panel**

1 capacitor banks at Gardenville Substation and connect them to the existing  
2 115kV busses. Including this project increases capital funding in FY13 by  
3 \$3.5 million and in FY14 by \$2 million. Accordingly, the total  
4 adjustments to the Southwest NY Reliability Criteria Compliance Program  
5 should be upward adjustments of \$10.25 million and \$4.29 million in  
6 FY13 and FY14, respectively, and a downward adjustment of \$0.300  
7 million in FY15.

8

9 **Q. Do the additions/accelerations of the identified projects affect any**  
10 **other projects in the transmission capital investment plan?**

11 A. Yes. There is a second major project at Gardenville Substation (under  
12 project C05156 (see Exhibit \_\_ (EIOP-5CU), p. 2 of 5), due for  
13 completion by FY 2017), which calls for the complete rebuild of the  
14 existing 115kV substation. The scope of project C05156 also includes  
15 four 115kV capacitor banks. The current plan is to disconnect three of the  
16 four capacitor banks installed under project C43735 from the existing  
17 115kV busses and move them to their final location in the rebuilt  
18 Gardenville Substation under project C05156. Thus, three of the four  
19 capacitor banks purchased under project C43725 will be used under  
20 project C05156. The fourth capacitor bank under project C05156 will be  
21 purchased in FY15 and installed at the appropriate time. The remaining

**Rebuttal Testimony of the Electric Infrastructure and Operations Panel**

1 capacitor bank installed under project C43735 will be disconnected from  
2 the system and maintained as a spare. Because the major material for  
3 three of the four 115kV capacitor banks purchased under project C43735  
4 will be utilized in the rebuilt Gardenville Substation, the Company  
5 proposes reducing the capital requirement for project C05156 by \$1.2  
6 million in FY15, which represents the material cost for the three capacitor  
7 banks.

8

9 **Q. Staff does not support a deferral mechanism for Dunkirk-related**  
10 **capital project costs that are not reflected in the Company's revenue**  
11 **requirement in this case and, presumably, also opposes discrete**  
12 **deferrals associated with the mothballing or closing of generation**  
13 **plants that have not yet been identified. Please respond.**

14 A. The Company disagrees with Staff's position that the Company should  
15 request deferral treatment under the Commission's regulations in the  
16 event material incremental costs are required to address generation  
17 retirements or mothballing. The Company understands Staff's  
18 disinclination to agree with special deferral mechanisms. However, the  
19 Company maintains that the circumstances presented by the Dunkirk  
20 mothballing demonstrate that this is sufficiently unusual to warrant a  
21 separate deferral mechanism.

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1           The Dunkirk mothballing situation is the first of its kind in New York  
2           State—previous generation plant shutdowns have not resulted in the  
3           reliability concerns presented here. Staff’s testimony recognizes the need  
4           for significant and expedited capital investment. While the Company has  
5           worked quickly to identify capital projects required to maintain reliable  
6           system performance once Dunkirk is unavailable, it is very likely that the  
7           analyses being performed by the Company will identify the need for  
8           additional projects. Niagara Mohawk will discuss its further analysis and  
9           determinations regarding additional projects with Staff. If Staff is in  
10          agreement that additional projects are necessary, the Company should  
11          have the authority to defer the associated costs to maintain reliable service  
12          to customers in the face of this unique event with major implications for  
13          system performance. Similarly, in the event of a presently unanticipated  
14          generation mothballing or closure that has significant reliability  
15          consequences, the Company would consult with Staff as to its analyses  
16          and any planned projects to address the reliability concerns. Subject to  
17          Staff’s agreement with the Company’s planned capital projects, the  
18          Company should be able to defer the associated costs.

19

20   **Q.   Does the Company agree with Staff’s recommendation regarding**  
21   **recovery of RSS agreement costs?**

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1 A. In part. The Staff Electric Infrastructure Panel recommends that a portion  
2 of the Company's forecast \$128 million of deferred liability be used to  
3 offset the current RSS costs. Staff recommends that, to the extent RSS  
4 costs continue in the future, a surcharge mechanism should be used to  
5 recover those costs. The Company agrees that offsetting current RSS  
6 costs with the forecast deferred liability is appropriate. However, it is  
7 unclear what current period Staff is referring to, as it might refer to the  
8 nine month initial contract term commencing September 1, 2012 and  
9 expiring May 31, 2013 or the period from September 1, 2012 until March  
10 31, 2012 prior to when new base rates will go into effect. The Company  
11 proposes to defer RSS costs from September 1, 2012 through March 31,  
12 2013 and to implement a surcharge to recover all RSS costs remaining to  
13 be reconciled or incurred on or after April 1, 2013 coincident with new  
14 base rates, as further discussed in the rebuttal testimony of the Electric  
15 Rate Design Panel. The Company agrees that offsetting the seven months  
16 (September 2012 – March 2013) of deferred RSS costs with the forecast  
17 deferred liability is reasonable and will mitigate the impact on customers.  
18 Subsequently, however, timely recovery of RSS costs from the  
19 mothballing of the Dunkirk units, as well as other RSS costs that arise  
20 prospectively, through a surcharge is important and reasonable in light of  
21 the unexpected and unusual circumstances, the modest impact this

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1 proceeding is expected to have on customer bills, and to preserve the  
2 regulatory liability for purposes of maintaining future rate stability for  
3 customers.

4

5 **Northeast Region Reinforcement—Spier-Rotterdam 115kV Line**

6 **Q. Does the Company agree with Staff’s recommendation to track and**  
7 **absorb any incremental costs associated with assuring that the Spier-**  
8 **Rotterdam steel poles are straight?**

9 A. Yes. The Company agrees that customers should not bear additional costs  
10 related to manufacturing issues affecting the straightness of the steel poles.  
11 The Company has been working closely with the pole manufacturer to  
12 assure the issues are addressed and anticipates that all incremental costs  
13 associated with addressing the straightness issues will be borne by the  
14 manufacturer. To the extent the Company incurs any incremental costs  
15 not covered by the manufacturer, it will expense those costs below the line  
16 to exclude them from future revenue requirements and/or earnings sharing  
17 calculations.

18

19 **Distribution Blanket Accounts**

20 **Q. Does the Company accept Staff’s proposed adjustments to four**  
21 **distribution blanket accounts (damage/failure, reliability, meters**

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1           **purchases and general equipment)?**

2    A.    In part. Staff recommends setting the funding levels for the identified  
3           blanket accounts at the average spending levels since January 1, 2011 for  
4           FY14 and applying a four percent annual escalation factor for FY15 and  
5           FY16. The Company accepts that historic expenditures and the proposed  
6           escalation rate for the Damage/Failure Blanket Account, the Reliability  
7           Blanket Account and the General Equipment Blanket Account are  
8           reasonable. The Company, however, does not accept Staff’s adjustment  
9           with respect to the Meter Purchases Blanket Account.

10  
11           Staff recommends downward adjustments of \$1.67 million, \$1.91 million  
12           and \$2.04 million in FY14, FY15, and FY16, respectively, for the Meter  
13           Purchases Blanket Account. The Company’s proposed funding levels for  
14           this blanket account were based on its base meter needs as well as  
15           sufficient funding to complete AMR installations for approximately two  
16           percent of customers. There are approximately 31,000 electric customers  
17           that do not have AMR technology installed on their meters (approximately  
18           10,000 transformer-rated meters and 21,000 self-contained meters), which  
19           represent the final two percent of customers without AMR meters. The  
20           Company proposes to complete installation of AMR technology for these  
21           customers over the next three years (FY14 – FY16). The funding levels

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1 proposed by Staff, while sufficient to accommodate the Company's base  
2 meter needs, are insufficient to address these AMR installations.  
3 Accordingly, the Staff's adjustments should be rejected.

4

5 **Buffalo Street Light Cable Replacement**

6 **Q. Does the Company agree with Staff's recommendation regarding the**  
7 **Buffalo Street Light Cable Replacement program?**

8 A. Yes. The Company accepts Staff's request that, by April 15, 2013, it  
9 submit a more comprehensive plan for implementing the program.

10

11 **Network Arc Flash Program**

12 **Q. Does the Company agree with Staff's proposed adjustments to the**  
13 **Network Arc Flash program?**

14 A. Yes. The Network Arc Flash program is a new program being  
15 implemented to comply with the 2012 edition of the NESC. Staff  
16 recommends, and the Company accepts, a reduction of \$2 million in the  
17 FY14 funding levels to allow for additional time to plan and prioritize  
18 work under the program.

19

20 **Side Tap Fusing**

21 **Q. Does the Company agree with Staff's proposed adjustment to the Side**

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1           **Tap Fusing program?**

2    A.    No. Staff recommends a downward adjustment of \$1.1 million from the  
3           Company's proposed \$1.8 million annual funding level primarily on the  
4           grounds that the Company has not spent the budgeted amount previously  
5           and did not identify the number of installations it planned to perform.

6  
7           This program, however, was budgeted and active for the first time in  
8           FY13. Under the program, the Company plans to review the fusing needs  
9           of 400 feeders each year. Thus far in FY13, 398 feeders have been  
10          reviewed and over 2,400 side tap fuse locations have been identified.  
11          Further, on those feeders, fuses would be beneficial on nearly 4,000  
12          completely self-protected unfused transformers to improve feeder  
13          protection schemes. In the first five months of the program (through  
14          August 2012), the Company has spent \$0.359 million and forecasts total  
15          FY13 spend of approximately \$1.3 million. As the program matures,  
16          cycle times are expected to be shorter and the Company expects to fully  
17          utilize the proposed budget. A significant reduction in program funding  
18          would substantially reduce the number of feeders the Company could  
19          review in the coming years. Therefore, Staff's adjustments should be  
20          rejected.

21

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1           **Smart Grid (“Advanced Grid Applications”)**

2   **Q.    Please address Staff’s proposed adjustments regarding Advanced**  
3           **Grid Application funding.**

4    A.    The Company did not request funding for the Advanced Grid Application.  
5           Estimated costs associated with this program were reflected in certain  
6           previously prepared documents that were included as workpapers and  
7           provided for information purposes only. Because program funding was  
8           not included in the Company’s capital investment plan, Staff’s  
9           adjustments should be rejected.

10

11           **Reserve Budgeting**

12   **Q.    Please address Staff’s proposed adjustments regarding the**  
13           **Company’s reserve budgets.**

14    A.    Staff proposes significant adjustments to the reserve funding for sub-  
15           transmission and distribution asset condition work. Staff asserts that the  
16           Company should do a better job forecasting asset condition work and  
17           reflecting it specifically in the capital plan. Although the Company agrees  
18           it would be preferable to know in advance what future work will present  
19           the highest priority, in practice, determining what work to perform when is  
20           influenced by a variety of dynamic issues. Factors such as scope changes,  
21           permitting issues, availability of planned interruptions, emerging condition

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1 or performance issues, severe weather, and customer-driven changes may  
2 affect the prioritization of work. Because these factors are difficult to  
3 project, the Company uses reserve budgets to manage work effectively  
4 and flexibly, which ultimately results in a more efficient capital plan and  
5 is in the best interest of customers. As Staff notes in its testimony, in IR  
6 DPS-393 (BWD-9) the Company identified a significant number of sub-  
7 transmission projects that could be funded under the reserve budget.

8 Typically these sub-transmission projects are needed to address potential  
9 safety or reliability concerns and can have a direct effect on customer  
10 reliability. The reductions proposed by Staff to the reserve budgets for  
11 sub-transmission (\$5.47 million in 2015 and \$7.29 million in 2016) and  
12 distribution (\$10 million in 2016) are substantial and would appreciably  
13 limit the Company's ability to efficiently deliver needed sub-transmission  
14 and distribution projects. Thus, Staff's adjustments should be rejected.

15

16 **Q. Has the Company prepared a summary of the capital adjustments**  
17 **discussed above?**

18 A. Yes. A summary of the capital adjustments accepted by the Company, the  
19 resulting capital funding levels, and the corresponding impacts on cost-of-  
20 removal are presented in Exhibit \_\_ (RRP-13R), p. 11 of 12.

21

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1 **Q. Has the Company reflected the adjustments to the capital investment**  
2 **plan in its revenue requirement?**

3 A. Yes. The impact of these adjustments is reflected in the revenue  
4 requirement as described in the rebuttal testimony of the Revenue  
5 Requirements Panel.

6

7 **III. Operations & Maintenance Expense**

8 **Operating Expense (“opex”) Associated with Incremental Capital**  
9 **Investment (“capex”)**

10 **Q. Please explain Staff’s proposed adjustment to reduce opex associated**  
11 **with incremental capex.**

12 A. Staff recommends a \$1 million flow-through adjustment to reduce opex  
13 associated with incremental capex based on Staff’s adjustments to the  
14 capital plan. The Company does not agree with all of Staff’s proposed  
15 capex adjustments and therefore does not agree with Staff’s adjustment.

16

17 **Q. What is the Rate Year impact on opex associated with incremental**  
18 **capex adjustments accepted by the Company?**

19 A. The Rate Year forecast of opex associated with incremental capex, as  
20 revised to reflect the Company’s acceptance of certain Staff adjustments,  
21 is approximately \$5.071 million, as shown in Exhibit \_\_ (RRP-13R), p. 12

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1 of 12. This represents a reduction of approximately \$0.517 million from  
2 the opex associated with incremental capex reflected in the Company's  
3 corrections and updates filing.

4

5 **Sub-Transmission Tower Painting**

6 **Q. Does the Company agree with Staff's recommendations regarding**  
7 **funding for sub-transmission tower painting?**

8 A. Yes. Staff accepted the Company's proposed funding level, but added that  
9 it should be subject to downward-only reconciliation and refund to  
10 customers of any difference between the rate allowance and the actual  
11 program expense consistent with the Company's proposal for transmission  
12 tower painting. In light of the challenges the Company has experienced  
13 with respect to tower painting, the Company accepts Staff's  
14 recommendation.

15

16 **Transmission Footer Inspection and Maintenance Program**

17 **Q. Does the Company agree with Staff's adjustment to the Transmission**  
18 **Footer Inspection and Maintenance Program?**

19 A. Yes. Staff recommends a downward adjustment of \$1 million, resulting in  
20 an annual funding allowance of \$2.441 million. The Company agrees that  
21 the 30 percent repair-to-inspection ratio Staff used to calculate the funding

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1 allowance is appropriate.

2

3 **Storm Fund – Contractor Disallowance and Information Tracking**

4 **Q. Does the Company agree with Staff’s recommendations regarding the**  
5 **contractor disallowance calculation used in the storm fund and the**  
6 **proposal to analyze additional information relating to certain major**  
7 **storm events?**

8 A. Yes. The Company accepts Staff’s proposal to include additional titles in  
9 the contractor disallowance calculation. In addition, the Company accepts  
10 Staff’s proposal that the Company perform a detailed analysis of costs  
11 following any storm event with more than ten days post-restoration work  
12 to gather information for use in future rate proceedings.

13

14 **Operations and Maintenance (“O&M”) Program Reporting**

15 **Q. Please respond to Staff’s recommendation to supplement current**  
16 **reporting requirements to include information on O&M programs.**

17 A. The Company’s O&M program budgets and tracking mechanisms are  
18 structured differently from its capital budget and investment tracking  
19 systems. The Company proposes to meet with Staff to discuss the type of  
20 information available for tracking and reporting and to better understand  
21 the nature of the information Staff is seeking. Thereafter, the Company

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1 and Staff would agree on the content and timing of supplemental reporting  
2 to be provided.

3

4 **IV. Staff Vegetation Management Panel**

5 **Transmission Vegetation Management**

6 **Q. What adjustments does Staff propose for transmission vegetation  
7 management?**

8 A. The Staff Vegetation Management Panel recommends a downward  
9 adjustment of \$0.700 million to the proposed transmission vegetation  
10 management funding level. Staff's proposed adjustments are based on its  
11 position that the need for certain vegetation management activities will be  
12 substantially reduced or eliminated in the Rate Year compared to the  
13 Company's projections.

14

15 **Q. Does the Company agree with Staff on this proposed adjustment?**

16 A. No. The Company maintains that its proposed allowances for mid-span  
17 mowing, off-cycle rights-of-way ("ROW") work and "trim-STC (stump,  
18 treat & chip)-mow" work are necessary to maintain reliable system  
19 performance.

20

21 With respect to its proposed adjustment of \$0.300 million for mid-span

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1 mowing, Staff maintains that there is little remaining mid-span mowing  
2 left to be done. While the Company agrees that mid-span mowing needs  
3 are declining, it will still be needed in the Rate Year and the costs are not  
4 negligible. The Company plans to perform mid-span mowing on portions  
5 of over two dozen lines listed in Exhibit \_\_ (EIOP-3R) to maintain safe  
6 clearances and reliable performance. The Company believes Staff's  
7 recommendation that it abruptly halt mid-span mowing is inconsistent  
8 with the obligation to maintain reliable service.

9

10 Staff also proposes a \$0.400 million adjustment related to off-cycle ROW  
11 work and trim-STC-mow work. Regarding off-cycle work, Staff asserts  
12 that mid-span mowing has vastly reduced the level of off-cycle work  
13 needed, which renders the use of historical average spending a poor  
14 predictor of future spending. However, mid-span mowing does not in all  
15 cases eliminate or even reduce the need for off-cycle work, which is  
16 unplanned or emergency work that occurs during the full term of the ROW  
17 cycle. Issues unaffected by mid-span mowing that can drive the need for  
18 off-cycle work include:

- 19 • Landowner interaction, including ROW usage for orchards and  
20 nurseries and tree removal requests for construction, farming and  
21 other reasons;



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1           which require techniques such as pruning, chipping and/or mowing to  
2           treat. These sites are inventoried and scheduled on cycle, but require  
3           special equipment (*e.g.*, bucket truck, chipper or mower). The work is  
4           variable by technique and more expensive than routine floor work and  
5           therefore is planned and budgeted separately. As the work is done on the  
6           same cycle as floor work, the Company used an average annual historic  
7           spend for the full cycle term (7 years) to estimate the revenue requirement  
8           for FY14. The Company applied the average cost per acre to the acres of  
9           trim-STC-mow work inventoried and scheduled for the Rate Year to arrive  
10          at its cost estimate of \$0.808 million in the Rate Year.

11  
12          Staff also asserts that the Commission's 2005 Order in Case 04-E-0822  
13          directing utilities to remove right-of-way trees should result in the costs of  
14          trim-STC-mow work going down as trimming work is eliminated.

15          Contrary to Staff's assumption, the majority of trim-STC-mow work  
16          projected for the Rate Year is not planned for transmission ROW, which  
17          was the primary focus of Case 04-E-0822. On the transmission system,  
18          voltages are higher, lines are higher, and the Company typically owns the  
19          ROW property interests. However, the majority of planned trim-STC-  
20          mow sites are on the Company's sub-transmission system, where voltages  
21          are lower, lines are lower, and property rights are primarily easements. Of

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1 the 3,542 trim-STC-mow sites in the treatment database, 3,030 are on sub-  
2 transmission ROWs. As a result, actions required by Case 04-E-0822  
3 have little effect on the need for this type of work.

4

5 **Distribution Vegetation Management**

6 **Q. Please address Staff's proposed adjustment to distribution vegetation**  
7 **management funding.**

8 A. While it acknowledges that the Company's distribution vegetation  
9 management program has been successful and has contributed to solid  
10 reliability performance in recent years, Staff recommends an adjustment of  
11 \$1.8 million on the basis that historic spending has been below budgeted  
12 levels for the past three years. Staff's adjustment is based on its  
13 calculation of the average percentage by which actual spending was below  
14 budget in the years Staff reviewed.

15

16 **Q. Does the Company agree with this adjustment?**

17 A. No. As Staff recognizes, the vegetation management program has been a  
18 success and boosted the reliable performance of the distribution system.  
19 Staff erroneously relies on historic spend even though the cost of  
20 distribution vegetation management is trending upwards, and then  
21 compounds its error by analyzing budgets versus historic spend. Staff's

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1 proposed adjustment would negatively impact the Company's ability to  
2 maintain cycle trim levels and jeopardize distribution system reliability.  
3  
4 Staff's analysis of historic spend was based on the Company's response to  
5 IR DPS-449 (CVB-1), a copy of which is included as Exhibit \_\_ (EIOP-  
6 4R). IR DPS-449 (CVB-1) shows that actual vegetation management  
7 spending increased 3.6 percent from FY10 to FY11, and 5.0 percent from  
8 FY11 to FY12. Thus, despite an increase in costs of nearly 8.8 percent  
9 from FY10 to FY12, the Company is proposing a FY14 funding level that  
10 is less than 1.3 percent greater than FY12 costs, while Staff's proposed  
11 adjustment would cut funding to 3.4 percent less than FY12 spending.  
12 This would impair the Company's ability to manage reliability and is not  
13 reasonable. Moreover, Staff's focus on the relationship between historic  
14 spending and budgets is irrelevant to establishing the appropriate Rate  
15 Year allowance for this work. Staff's comparison of budgets to actuals for  
16 FY10 sheds no light on the appropriate rate allowance in FY14. A more  
17 appropriate analysis would be to compare calendar year 2011 (25 percent  
18 of FY11 and 75 percent of FY12) actual spend of \$39.2 million, which  
19 exceeded the \$38.4 million rate allowance reflected in the CapEx/OpEx  
20 Stipulation in the 2010 Electric Rate Case.

21

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1 Staff's recommended adjustment is based on a flawed analysis and would  
2 result in unwarranted funding reductions below current and historic  
3 spending levels and would adversely affect the Company's ability to  
4 maintain reliability.

5

6 **V. Staff Reliability Performance Mechanism Panel**

7 **Inspection and Maintenance ("I&M") Repair Metric**

8 **Q. Please describe Staff's proposed performance metric for I&M**  
9 **program repairs.**

10 A. Staff recommends establishing a new performance metric for the repair of  
11 Level II and Level III deficiencies. Specifically, Staff proposes a  
12 mechanism with a negative revenue adjustment of \$2 million in the event  
13 the Company does not repair at least 85 percent of Level II deficiencies  
14 and at least 75 percent of Level III deficiencies identified through the I&M  
15 program within the allotted repair time periods (*i.e.*, one year for Level II  
16 and three years for Level III).

17

18 **Q. Does the Company agree with Staff's proposal?**

19 A. No. The Company's performance on Level II and Level III deficiency  
20 repairs has been satisfactory and does not warrant imposition of a potential  
21 negative revenue adjustment. Exhibit \_\_ (EIOP-5R) provides a summary

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1 of identified deficiencies and repair activity for calendar year 2009  
2 through August 31, 2012. The table shows, by year, the number of Level  
3 II and III deficiencies identified by priority level, the number of repairs  
4 made within and beyond the respective timeframes, and the number of  
5 deficiencies that have not yet been repaired, whether current or overdue.  
6 The overwhelming number of deficiencies have either been repaired  
7 within the applicable timeframes or are not yet due for repairs. For  
8 example, of the deficiencies found in 2009, over 97 percent of the 20,358  
9 total Level II items were repaired on time and over 90 percent of the  
10 59,068 total Level III items were either repaired on time (83 percent) or  
11 are not yet due (7.7 percent). For 2010, more than 93 percent of the  
12 21,435 Level II items were fixed on time and of the 41,057 Level III  
13 items, nearly 27 percent have already been repaired and none of the  
14 remaining items are overdue. Given its repair program and schedule, the  
15 Company is on track to complete repairs on remaining items and newly  
16 identified ones within the respective timeframes. Staff's concern is  
17 unsupported and no performance metric is required.

18

19 **Q. Would the imposition of a new metric create other challenges?**

20 A. Yes. The Company makes every effort to schedule repairs identified  
21 under the I&M program in the most efficient manner possible. This

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1 includes evaluating repairs within the respective program timeframes and  
2 coordinating repairs with other work when possible. Establishing a  
3 performance metric with negative revenue exposure may create a  
4 disincentive to coordinate repairs and reduce overall program efficiency,  
5 which could increase costs. This unintended consequence and the  
6 negligible potential increase in on-time repair rates militates against  
7 imposition of a new metric. However, given Staff's concern with the  
8 timing of I&M repairs, the Company proposes to consult with Staff  
9 regarding program implementation to determine what if any additional  
10 program reporting would address Staff's concerns.

11

12 **Estimating Performance Metric**

13 **Q. Please respond to Staff's proposed changes to the estimating**  
14 **performance metric.**

15 A. The Company accepts Staff's proposed modification of the potential  
16 negative revenue adjustment calculation. The Company also accepts the  
17 exemption provision included in Exhibit \_\_ (RPM-1), which is a  
18 continuation of the existing provision. The Company does not accept  
19 narrowing the existing exemption provision.

20

21 Staff does not agree with the Company's proposal to exclude generator

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1 interconnection and DOT/public works projects from the metric  
2 calculation, but instead states in its testimony that if “DOT or  
3 interconnection projects are the sole reason for the Company failing to  
4 meet its estimating [reliability performance metric],” the Company could  
5 petition the Commission for an exemption. (Staff Reliability Performance  
6 Mechanism Panel at 7-8). The ability to seek an exemption in certain  
7 circumstances is essential to the fair operation of the estimating  
8 performance metric. In fact, the language included in Staff’s proposed  
9 service quality assurance program attachment (Exhibit \_\_ (RPM-1), p. 7 of  
10 8) provides that: “[t]he Company has the right to request exceptions for  
11 discrete projects where there are scope changes or significant  
12 circumstances.” However, Staff’s testimony suggesting that such  
13 exemption would apply only if interconnection or DOT projects are the  
14 “sole reason” for failing the metric is too strict. Given that the language in  
15 Exhibit \_\_ (RPM-1) is a continuation of the existing exemption language  
16 for the estimating metric, and that the rest of Staff’s testimony does not  
17 reveal an intention to restrict the currently existing exemption provision,  
18 the Company believes the Staff RPM Panel’s use of the word “sole” in its  
19 testimony was in error. If it was intended, however, the Company opposes  
20 it.

21

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1 **VI. Allocation of Costs Associated with Distribution Load Dispatch and**  
2 **the Primary and Secondary Distribution Systems**

3 **Q. Multiple Intervenors raises certain allocation issues relating to**  
4 **Distribution Load Dispatch and the functions of the Primary and**  
5 **Secondary Distribution Systems. Please respond.**

6 A. Distribution Load Dispatch is an activity that must be performed minute-  
7 by-minute, not just during peak periods, because it supports system  
8 reliability, which must be maintained at all times. The main determinant  
9 for Distribution Load Dispatch labor costs is staffing levels, which are  
10 related to the amount of maintenance being done on the system at a given  
11 time because operator actions are required to coordinate such work with  
12 line loading, and to divert load when necessary, in addition to managing  
13 supply and delivery of electricity.

14  
15 The Primary and Secondary Distribution Systems are comprised of  
16 similar, but not identical asset classes and serve different functions. The  
17 Secondary System consists of assets that are related to serving individual  
18 customers, whereas assets comprising the Primary System are situated  
19 farther “upstream” and serve more of a network role. In light of the  
20 functions performed by the two systems, it is reasonable to classify a  
21 smaller portion of the Primary System as customer-related as compared to

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1           the Secondary System. Accordingly, the classification of approximately  
2           one-half of the Primary System as customer-related as described in the  
3           rebuttal testimony of the Electric Rate Design Panel is reasonable.

4

5 **VII. Conclusion**

6 **Q. Does this conclude the Panel's testimony?**

7 A. Yes, it does.



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**List of Exhibits**

Exhibit __ (EIOP-1R)	Transmission Capital Plan – Revised
Exhibit __ (EIOP-2R)	Distribution Capital Plan – Revised
Exhibit __ (EIOP-3R)	Mid-span mowing table of planned sites
Exhibit __ (EIOP-4R)	Copy of Response to IR DPS-449 (CVB-1)
Exhibit __ (EIOP-5R)	I&M Repair Performance CY2009-Aug. 31, 2012



**Case 12-E-0201**

**Rebuttal Testimony of the Electric Infrastructure and Operations Panel**

Exhibit \_\_ (EIOP-1R)

Transmission Capital Plan – Revised

Transmission Capital Investment Plan FY13 - FY17 (Revision for Rebudget)

Accepted Adjustments Reflected

Spending Rationale	Program	Project Name	Project#	FY13	FY14	FY15	FY16	FY17	TOTAL
Asset Condition	Battery Strategy	Battery Replacement Strategy Co. 36 T&T	C33847	\$ 490,000	\$ 450,000	\$ 170,000	\$ 220,000	\$ 160,000	\$ 1,490,000
	<b>Battery Strategy Total</b>			\$ 490,000	\$ 450,000	\$ 170,000	\$ 220,000	\$ 160,000	\$ 1,490,000
	Flying Ground Strategy	Buffalo/Albany Flying Grounds Switch Rpl	C33613	\$ 200,000	\$ 856,000	\$ 1,367,000	\$ -	\$ -	\$ 2,423,000
	<b>Flying Ground Strategy Total</b>			\$ 200,000	\$ 856,000	\$ 1,367,000	\$ -	\$ -	\$ 2,423,000
	Oil Circuit Breaker Strategy	NY Oil Circuit Breaker Replacements	C37882	\$ 700,000	\$ 2,100,000	\$ 2,450,000	\$ 3,900,000	\$ 4,550,000	\$ 13,700,000
	<b>Oil Circuit Breaker Strategy Total</b>			\$ 700,000	\$ 2,100,000	\$ 2,450,000	\$ 3,900,000	\$ 4,550,000	\$ 13,700,000
	Other Asset Condition	ALCOA - Add Annunciator	C19934	\$ 50,000	\$ -	\$ -	\$ -	\$ -	\$ 50,000
		Alps #188 Obsolete Circuit Switcher	C28304	\$ 704,000	\$ -	\$ -	\$ -	\$ -	\$ 704,000
		BuffaloSta 64-Rpl LN182 RFL Tone Eq	C31950	\$ 504,780	\$ -	\$ -	\$ -	\$ -	\$ 504,780
		Elm Terminal Station - HPPF Alarms	C30528	\$ 35,000	\$ 55,000	\$ -	\$ -	\$ -	\$ 90,000
		Gardenville Station - HPPF Alarms	C30530	\$ 35,000	\$ 55,000	\$ -	\$ -	\$ -	\$ 90,000
		Harper Station	C37203	\$ 50,000	\$ 650,000	\$ -	\$ -	\$ -	\$ 700,000
		Higley-Repl Fuses w/Ckt Switcher	C34664	\$ -	\$ -	\$ 25,000	\$ 655,000	\$ -	\$ 680,000
		Huntley Station - HPPF Alarms	C30531	\$ 35,000	\$ 55,000	\$ -	\$ -	\$ -	\$ 90,000
		Inman Rd - Install Circuit Switcher	C30765	\$ 60,760	\$ -	\$ -	\$ -	\$ -	\$ 60,760
		Mallory Road Ground Protection	C37408	\$ 23,000	\$ -	\$ -	\$ -	\$ -	\$ 23,000
		OswegoPumpHouseAlarmsPIW012-2005	C36219	\$ 32,000	\$ -	\$ -	\$ -	\$ -	\$ 32,000
		PIW/Emergent Projects	CNYX72	\$ 1,000,000	\$ 1,000,000	\$ 1,000,000	\$ 1,000,000	\$ 1,000,000	\$ 5,000,000
		Porter Replace 11 GE 230KV RFL Discs	C20912	\$ 445,000	\$ -	\$ -	\$ -	\$ -	\$ 445,000
		Replace NG ALCOA 115 KV Breakers	C30545	\$ 702,000	\$ -	\$ -	\$ -	\$ -	\$ 702,000
		Rochester - Generator & HPPF Alarms	C30532	\$ 35,000	\$ 55,000	\$ -	\$ -	\$ -	\$ 90,000
		Rochester Pump - LPPF Trip Scheme	C29946	\$ 50,000	\$ 420,000	\$ -	\$ -	\$ -	\$ 470,000
		Rochester UG Pumping Plant	C15988	\$ -	\$ 100,000	\$ 700,000	\$ 140,000	\$ -	\$ 940,000
		Sleight-Auburn 3 T2560 Avian Mitigt	C39165	\$ -	\$ 25,000	\$ -	\$ -	\$ -	\$ 25,000
		Temple Pressuring Plant	CNYX26	\$ -	\$ 24,000	\$ 61,000	\$ 940,000	\$ -	\$ 1,025,000
	<b>Other Asset Condition Total</b>			\$ 3,761,540	\$ 2,439,000	\$ 1,786,000	\$ 2,735,000	\$ 1,000,000	\$ 11,721,540
	Overhead Line Refurbishment Program - Asset	Alabama - Telegraph 115 & 111 Tap Refurbishment T15304	C33014	\$ 50,000	\$ 250,000	\$ 900,000	\$ 3,600,000	\$ -	\$ 4,800,000
		Bethlehem - Albany 18 T5070 ACR	CNYAS71	\$ -	\$ 65,000	\$ 11,000	\$ 75,000	\$ 450,000	\$ 537,000
		Boonville - Porter [J]-2 [T4020]-T4030 ACR	CNYAS48	\$ -	\$ -	\$ -	\$ -	\$ 100,000	\$ 100,000
		Boonville - Rome #3	CNYAS54	\$ -	\$ 75,000	\$ 100,000	\$ 500,000	\$ 9,100,000	\$ 9,775,000
		Boonville-BF 1-2 T3140-T3150 ACR	C36164	\$ -	\$ 50,000	\$ 50,000	\$ 250,000	\$ 1,000,000	\$ 1,350,000
		Colton-BF 1-2 T3140-T3150 ACR	C27422	\$ 50,000	\$ 200,000	\$ 1,500,000	\$ 6,500,000	\$ 9,250,000	\$ 17,500,000
		Falconer-HH 153-154, T1160-T1170 ACR	C34193	\$ 50,000	\$ 50,000	\$ 1,000,000	\$ -	\$ -	\$ 1,100,000
		Gard-Dun 141-142 T1260-70 ACR Sence	C27425	\$ 25,000	\$ 25,000	\$ 330,000	\$ 1,230,000	\$ 3,000,000	\$ 4,610,000
		Gardenville - HH 151-152, T1950-T1280-S ACR	C27436	\$ 47,000	\$ 50,000	\$ 500,000	\$ 5,000,000	\$ 6,400,000	\$ 11,997,000
		Gardenville Lines 180-182, T1660-T1780 ACR	C03389	\$ 500,000	\$ 1,000,000	\$ 3,000,000	\$ 9,000,000	\$ 14,000,000	\$ 27,500,000
		Gardenville-Dunkirk 141-142 T1260-1270 ACR	C04718	\$ 264,000	\$ -	\$ -	\$ -	\$ -	\$ 264,000
		Gardenville-Homer Hill 151-152, T1950-T1280 N ACR - W	C27429	\$ 50,000	\$ 400,000	\$ 3,000,000	\$ 6,500,000	\$ 14,500,000	\$ 24,450,000
		Homer Hill Bennett Rd 157, T1340 ACR	C03422	\$ 50,000	\$ 50,000	\$ 200,000	\$ 200,000	\$ 1,000,000	\$ 1,500,000
		Lockport-Batavia 112, T1510 ACR	C27431	\$ 25,000	\$ 25,000	\$ 25,000	\$ 50,000	\$ 1,450,000	\$ 1,575,000
		Lockport-Batwa 108 Refurb	C03417	\$ 19,410,000	\$ 19,780,000	\$ 4,004,000	\$ -	\$ -	\$ 43,194,000
		Lockport-Mortimer 111 T1530 ACR	CNYAS65	\$ -	\$ -	\$ 50,000	\$ 50,000	\$ 500,000	\$ 600,000
		Mortimer - Pannell Road #24 & 25	CNYAS116	\$ -	\$ -	\$ -	\$ -	\$ 50,000	\$ 50,000
		Packard-Urban 181 T1850 STR	C30889	\$ -	\$ -	\$ 50,000	\$ 100,000	\$ 500,000	\$ 650,000
		Pannell-Geneva 4-4A, T1860 ACR	C30890	\$ 300,000	\$ 2,500,000	\$ 3,000,000	\$ 9,500,000	\$ 15,500,000	\$ 30,800,000
		Porter Rotterdam 31, T4210 ACR	CNYAS76	\$ -	\$ -	\$ -	\$ -	\$ 85,000	\$ 85,000
		Rotterdam - Bear Swamp E205 T5630 ACR	C21694	\$ 50,000	\$ 65,000	\$ 65,000	\$ 330,000	\$ 6,000,000	\$ 6,510,000
		Spier-West 9 Refurbishment T5770 ACR	C27437	\$ 100,000	\$ 600,000	\$ 4,200,000	\$ 4,200,000	\$ -	\$ 9,100,000
		Taylorville - Boonville 5-6 T3320-T3330 ACR	C24361	\$ 600,000	\$ 2,500,000	\$ 3,000,000	\$ -	\$ -	\$ 6,100,000
		Taylorville-Moshier 7, T3340 LER - Central Div.	CNYAS112	\$ -	\$ -	\$ -	\$ -	\$ 65,000	\$ 65,000
		Terminal - Schuyler 7 T4260 ACR	C39521	\$ 15,000	\$ 100,000	\$ 150,000	\$ 1,500,000	\$ 12,000,000	\$ 13,165,000
		Ticonderoga 2-3 T5810-T5830 ACR	C39487	\$ 1,000,000	\$ 600,000	\$ -	\$ -	\$ -	\$ 1,600,000
		Ticonderoga 2-3 T5810-T5830 SXR2	CNYAS50	\$ -	\$ -	\$ -	\$ -	\$ 70,000	\$ 70,000
		Warrensburg - Scofield Road 10 T5880 ACR	C34690	\$ 22,586,000	\$ 28,385,000	\$ 25,135,000	\$ 48,596,000	\$ 95,020,000	\$ 219,722,000
	<b>Overhead Line Refurbishment Program - Asset Condition Total</b>			\$ 22,586,000	\$ 28,385,000	\$ 25,135,000	\$ 48,596,000	\$ 95,020,000	\$ 219,722,000
	Relay Replacement Strategy	Relay Replacement Strategy	C34690	\$ 1,280,000	\$ 4,000,000	\$ 4,000,000	\$ 10,000,000	\$ 16,880,000	\$ 36,160,000
	<b>Relay Replacement Strategy Total</b>			\$ 1,280,000	\$ 4,000,000	\$ 4,000,000	\$ 10,000,000	\$ 16,880,000	\$ 36,160,000
	Reserve - Asset Condition	Capital Reserve - Asset Condition	CNYX31AC	\$ (5,685,772)	\$ (4,613,012)	\$ (1,213,945)	\$ (7,043,782)	\$ (14,134,558)	\$ (32,691,069)
	<b>Reserve - Asset Condition Total</b>			\$ (5,685,772)	\$ (4,613,012)	\$ (1,213,945)	\$ (7,043,782)	\$ (14,134,558)	\$ (32,691,069)

Transmission Capital Investment Plan FY13 - FY17 (Revision for Rebudget)

Accepted Adjustments Reflected

Spending Rationale	Project Name	Project#	FY13	FY14	FY15	FY16	FY17	TOTAL	
Shieldwire Strategy	Shieldwire - Clays-Dewitt 3 - Central Div.	C28709	\$ 1,000,000	\$ -	\$ -	\$ -	\$ -	\$ 1,000,000	
	Shieldwire - Gardenville-Buffalo 145-146	C28683	\$ 1,001,300	\$ 2,136,000	\$ -	\$ -	\$ -	\$ 3,137,300	
	Shieldwire - Huntley-Gardenville 38-39 - Western Div.	C28676	\$ 341,500	\$ -	\$ -	\$ -	\$ -	\$ 341,500	
	Shieldwire - Gardenville-Depew 54	C28706	\$ 50,000	\$ 510,000	\$ -	\$ -	\$ -	\$ 560,000	
	<b>Shieldwire Strategy Total</b>		\$ 2,392,800	\$ 2,646,000	\$ -	\$ -	\$ -	\$ 5,038,800	
	Steel Tower Strategy	Lockport 103-104, T1620-T106 STR	C27432	\$ 50,000	\$ -	\$ -	\$ -	\$ 50,000	
		S. Oswego Lighthouse Hill Circuits	C21693	\$ 289,997	\$ -	\$ -	\$ -	\$ 289,997	
	<b>Steel Tower Strategy Total</b>		\$ 339,997	\$ -	\$ -	\$ -	\$ -	\$ 339,997	
	Substation Rebuild	Dunkirk Rebuild	C05155	\$ -	\$ -	\$ -	\$ -	\$ 50,000	
		Gardenville - Rebuild Line Location	C30084	\$ 170,000	\$ 653,000	\$ 2,199,000	\$ 2,199,000	\$ 3,317,000	
Gardenville 115KV Station Rebuild		C05156	\$ 1,000,000	\$ 4,000,000	\$ 18,800,000	\$ 22,000,000	\$ 57,800,000		
LightHH 115KV Yard Repl & cntrl hse		C31662	\$ -	\$ -	\$ -	\$ 500,000	\$ 500,000		
N. Leroy Rebuild Station		C29180	\$ 178,000	\$ -	\$ -	\$ -	\$ -		
Rome 115 KV Station		C03778	\$ 4,765,000	\$ 2,780,000	\$ 1,216,000	\$ -	\$ 8,761,000		
Rome Rebuild Line Portion		C34983	\$ 240,000	\$ 421,000	\$ 55,000	\$ -	\$ 716,000		
Huntley Rebuild		CNYAS119	\$ -	\$ -	\$ -	\$ -	\$ 500,000		
<b>Substation Rebuild Total</b>			\$ 6,353,000	\$ 7,854,000	\$ 22,270,000	\$ 24,699,000	\$ 17,567,000	\$ 78,743,000	
Transformer Replacement Program		Greenbush - Replace TB3	C31663	\$ 2,120,000	\$ -	\$ -	\$ -	\$ -	
	NY Spare Transformers	C39883	\$ 2,059,000	\$ -	\$ -	\$ -	\$ -		
	Oneida Transformer Replacement # 4	C37876	\$ 750,000	\$ 820,000	\$ -	\$ -	\$ -		
	<b>Transformer Replacement Program Total</b>		\$ 4,929,000	\$ 820,000	\$ -	\$ -	\$ -	\$ 5,749,000	
	U-Series Relay Strategy	Edic FE1 - Replace U Series Relays	C24662	\$ 240,000	\$ -	\$ -	\$ 365,000	\$ 396,365	
		Leeds - Replace U Series Relays	C24663	\$ -	\$ -	\$ -	\$ 1,104,000	\$ 1,104,000	
		LN17 - Replace Type U Series Relays	C24661	\$ 2,803,000	\$ -	\$ -	\$ -	\$ -	
		Rotterdam-Repl E205 U Series Relays	C05150	\$ 162,320	\$ -	\$ -	\$ -	\$ -	
		<b>U-Series Relay Strategy Total</b>		\$ 3,205,320	\$ -	\$ -	\$ 1,469,000	\$ 1,500,446	\$ 6,174,766
	Asset Condition Total	NY Inspections	C26923	\$ 40,551,884	\$ 44,936,988	\$ 55,964,655	\$ 84,575,218	\$ 122,592,888	\$ 348,621,033
Other Damage Failure		C40504	\$ 145,000	\$ -	\$ -	\$ -	\$ -		
Bethlehem Station #21		C41010	\$ 208,000	\$ -	\$ -	\$ -	\$ -		
Curtis Str - Repl LN 10 & 13 Relays		C29320	\$ 20,000	\$ -	\$ -	\$ -	\$ -		
Gardin-Depew 54 T1230 Str 23-25 DF		C39207	\$ 78,000	\$ -	\$ -	\$ -	\$ -		
Geres Lock Sub - Repl 14 115KV Disc		C28324	\$ 311,000	\$ -	\$ -	\$ -	\$ -		
Grooms Rd-Foris F 13 T6360 Gravel P		C38382	\$ 100,000	\$ 1,400,000	\$ 60,000	\$ -	\$ -		
Line Failure Reserve		C03278	\$ 250,000	\$ 250,000	\$ 250,000	\$ 250,000	\$ 250,000		
Mohawk River Crossing D-F		C41086	\$ 180,000	\$ -	\$ -	\$ -	\$ -		
N Gouvern-Battle Hill 8 T3290 Switch		C35355	\$ 157,075	\$ -	\$ -	\$ -	\$ -		
NY Inspections Total	NY Priority Replace Priority 4 Transformers	C31656	\$ -	\$ 107,000	\$ 2,940,000	\$ 3,000,000	\$ 3,600,000		
	Oneida - TB#3 Failure	C22391	\$ -	\$ 500,000	\$ -	\$ -	\$ -		
	Packard - Urban 181 T1850 Str. 409 D-F	C41163	\$ 100,000	\$ -	\$ -	\$ -	\$ -		
	Packard-Gardenville 182 T1780 Str 87	C40784	\$ 120,000	\$ -	\$ -	\$ -	\$ -		
	Station Failure Reserve	C03792	\$ 5,244,000	\$ 4,750,000	\$ 4,750,000	\$ 4,750,000	\$ 4,750,000		
	T1060 X0045 Retired Olin Tap DF	C38884	\$ 46,000	\$ 223,000	\$ -	\$ -	\$ -		
	T3030 - T6180 Switch Replacements	C35384	\$ 190,660	\$ -	\$ -	\$ -	\$ -		
	TiconderogaSub Line Bypass	C39484	\$ 20,000	\$ 516,000	\$ -	\$ -	\$ -		
	TiconderogaSub1WRepl 115KV Switch	C37108	\$ 20,000	\$ 254,000	\$ -	\$ -	\$ -		
	Trinity UG CP DF	C40364	\$ 20,000	\$ -	\$ -	\$ -	\$ -		
Other Damage Failure Total	Yahnudasis T4160-T4300 D-F Struc	C38162	\$ 200,000	\$ -	\$ -	\$ -	\$ -		
	New Scotland - Replace Bus 99K Voltage Transformers and	C39722	\$ 275,000	\$ -	\$ -	\$ -	\$ -		
	<b>Other Damage Failure Total</b>		\$ 7,684,735	\$ 8,000,000	\$ 8,000,000	\$ 8,000,000	\$ 8,600,000	\$ 40,284,735	
	Woodpole Strategy	C11640	\$ 5,238,100	\$ 2,706,996	\$ 1,433,000	\$ 1,433,000	\$ 1,433,000		
	<b>Woodpole Strategy Total</b>		\$ 5,238,100	\$ 2,706,996	\$ 1,433,000	\$ 1,433,000	\$ 1,433,000	\$ 12,244,096	
	Damage Failures Total	Physical Security	C34224	\$ 14,038,835	\$ 11,822,996	\$ 10,549,000	\$ 10,549,000	\$ 11,149,000	\$ 58,108,831
		Non - Infrastructure	CNYAS86	\$ 1,500,000	\$ -	\$ -	\$ -	\$ -	
		Physical Security Strategy		\$ 50,000	\$ 50,000	\$ -	\$ -	\$ -	
		<b>Physical Security Total</b>		\$ 1,550,000	\$ 50,000	\$ -	\$ -	\$ -	\$ 1,600,000
		<b>Non - Infrastructure Total</b>		\$ 1,550,000	\$ 50,000	\$ -	\$ -	\$ -	\$ 1,600,000

Accepted Adjustments Reflected

Transmission Capital Investment Plan FY13 - FY17 (Revision for Rebuttal)

Spending Rationale	Program	Project Name	Project#	FY13	FY14	FY15	FY16	FY17	TOTAL		
Statutory Regulatory	Clay Station Rebuild	Clay Station Line Project	C32539	\$ 582,000	\$ 1,253,000	\$ -	\$ -	\$ -	\$ 1,835,000		
	Clay Station Rebuild Total			\$ 582,000	\$ 1,253,000	\$ -	\$ -	\$ -	\$ 1,835,000		
Clearance Strategy	Clearance Strategy	Adams-Packard 187 T1010 & Taps CCR	C34927	\$ -	\$ 10,000	\$ -	\$ -	\$ -	\$ 10,000		
		Adams-Packard 188 T1020 & Taps CCR	C34928	\$ -	\$ 10,000	\$ -	\$ -	\$ -	\$ 10,000		
		Adams-PV 91 T4320 CCR	C40463	\$ 10,000	\$ -	\$ -	\$ -	\$ -	\$ 10,000		
		Bethlehem-Albany 18 T5070 CCR	C34967	\$ -	\$ 10,000	\$ -	\$ -	\$ -	\$ 10,000		
		Boonville-Porter 2 T4030 CCR	C40683	\$ 10,000	\$ -	\$ -	\$ -	\$ -	\$ 10,000		
		Clay-General Electric 14 T2750 CCR	C41645	\$ 5,000	\$ -	\$ -	\$ -	\$ -	\$ 5,000		
		Dunkirk-South Ripley 68 T1110 CCR	C34912	\$ -	\$ 10,000	\$ -	\$ -	\$ -	\$ 10,000		
		Gardenville-Buff Rvr. 145 & 146 T210-220 CCR	C31155	\$ -	\$ 10,000	\$ -	\$ -	\$ -	\$ 10,000		
		Gardinvl-Beth 149-150 T1190-T1200 CCR	C34957	\$ -	\$ 10,000	\$ -	\$ -	\$ -	\$ 10,000		
		Geres Lock-Solvay 2 T2270 & Taps CCR	C34971	\$ -	\$ 10,000	\$ -	\$ -	\$ -	\$ 10,000		
		Goliah-Lakville 116 T1320 & Taps CCR	C34954	\$ -	\$ 10,000	\$ -	\$ -	\$ -	\$ 10,000		
		Greenbush-Stephentown 993 T5190 CCR	C31132	\$ -	\$ 10,000	\$ -	\$ -	\$ -	\$ 10,000		
		Hartfield-Moons 159 T1330 & Taps CCR	C34926	\$ -	\$ 10,000	\$ -	\$ -	\$ -	\$ 10,000		
		Homier H-Dugan Rd 155 T1350&Taps CCR	C34962	\$ -	\$ 10,000	\$ -	\$ -	\$ -	\$ 10,000		
		Hudson Pleasant Valley 12 T5330 CCR	C31145	\$ -	\$ 10,000	\$ -	\$ -	\$ -	\$ 10,000		
		Lighthouse Hill - Clay #7 CCR)	C39322	\$ 70,000	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 70,000	
		Lockport-Baitva, 107, T1490 CCR	C31149	\$ -	\$ 10,000	\$ 351,200	\$ -	\$ -	\$ -	\$ 361,200	
		Meco Rotterdam 10, T5390 CCR	C31134	\$ -	\$ 10,000	\$ -	\$ -	\$ -	\$ -	\$ 10,000	
		Mortimer Elbridge 2, T1570 CCR	C31135	\$ -	\$ 10,000	\$ -	\$ -	\$ -	\$ -	\$ 10,000	
		Mortimer Golah 110, T1580 CCR	C31150	\$ -	\$ 10,000	\$ -	\$ -	\$ -	\$ -	\$ 10,000	
		Mortimer Pannell, 24&25, T1590-T1600 CCR	C31148	\$ -	\$ 10,000	\$ -	\$ -	\$ -	\$ -	\$ 10,000	
		Mortimer Quaker 23, T1610 CCR	C31146	\$ -	\$ 10,000	\$ -	\$ -	\$ -	\$ -	\$ 10,000	
		Mountain-Loxopt 103 T1620 & Taps CCR	C34955	\$ -	\$ 10,000	\$ -	\$ -	\$ -	\$ -	\$ 10,000	
		New Scotland-Bethlehem 4 T5460 CCR	C34910	\$ -	\$ 10,000	\$ -	\$ -	\$ -	\$ -	\$ 10,000	
		New Scotland-Albany 8 T5980&Taps CCR	C34959	\$ -	\$ 10,000	\$ -	\$ -	\$ -	\$ -	\$ 10,000	
		Niagara Lockport 101, T1690 CCR	C31151	\$ -	\$ 10,000	\$ -	\$ -	\$ -	\$ -	\$ 10,000	
		Nine Mile One-Seriba 9 T2370 CCR	C40329	\$ 10,000	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 10,000	
		NS-Feura Bush 9 T5500 & Taps CCR	C34968	\$ -	\$ 10,000	\$ -	\$ -	\$ -	\$ -	\$ 10,000	
		NS-Long Lane T5470 & Taps CCR	C34966	\$ -	\$ 10,000	\$ -	\$ -	\$ -	\$ -	\$ 10,000	
		Oneida-Porter 7 T4150 CCR	C41366	\$ 5,000	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 5,000	
		Packard-Huntley 130, T1820 CCR	C31154	\$ -	\$ 10,000	\$ -	\$ -	\$ -	\$ -	\$ 10,000	
		Reynolds Rd-New Scotland 13 T5560 CCR	C34964	\$ -	\$ 10,000	\$ -	\$ -	\$ -	\$ -	\$ 10,000	
		Rotterdam Altamont 17, T5620 CCR	C31131	\$ -	\$ 10,000	\$ -	\$ -	\$ -	\$ -	\$ 10,000	
		Rotterdam-New Scotland 13 T5680 CCR	C34963	\$ -	\$ 10,000	\$ -	\$ -	\$ -	\$ -	\$ 10,000	
		Transmission Tower Clearances	C03256	\$ 5,800,000	\$ 7,000,000	\$ 15,000,000	\$ 15,000,000	\$ -	\$ -	\$ 57,800,000	
		Valley Sta 444-Isshua 158 T1900 CCR	C34965	\$ -	\$ 10,000	\$ -	\$ -	\$ -	\$ -	\$ 10,000	
		<b>Clearance Strategy Total</b>			<b>\$ 5,910,000</b>	<b>\$ 7,300,000</b>	<b>\$ 15,351,200</b>	<b>\$ 15,000,000</b>	<b>\$ 15,000,000</b>	<b>\$ 58,561,200</b>	
		Generation	Clearance Strategy Total	Alabama Ledge Wind-Loop in, Loop-out	CNYX63	\$ -	\$ 290,000	\$ 245,000	\$ -	\$ -	\$ 535,000
				Alabama Ledge Wind-Loop in, Loop-out Reimbursable por	CNYX63R	\$ -	\$ (290,000)	\$ (245,000)	\$ -	\$ -	\$ (535,000)
				Alabama Ledge Wind-RTU/Metering/Relay upgrades	CNYX64	\$ -	\$ 490,000	\$ 1,092,000	\$ 260,000	\$ -	\$ 1,842,000
				Alabama Ledge Wind-RTU/Metering/Relay upgrades-Reimb	CNYX64R	\$ -	\$ (490,000)	\$ (1,092,000)	\$ (260,000)	\$ -	\$ (1,842,000)
				Althens Redundant SPS	CNYX83	\$ 675,000	\$ -	\$ -	\$ -	\$ -	\$ 675,000
Althens Redundant SPS - Reimbursable Portion	CNYX83R			\$ (675,000)	\$ -	\$ -	\$ -	\$ -	\$ (675,000)		
Ball Hill- Loop in, Loop out	CNYX74			\$ 150,000	\$ 700,000	\$ 484,000	\$ 140,700	\$ -	\$ 1,474,700		
Ball Hill- Loop in, Loop out Reimbursable Portion	CNYX74R			\$ (150,000)	\$ (700,000)	\$ (484,000)	\$ (140,700)	\$ -	\$ (1,474,700)		
Ball Hill-Metering/RTU/Relay Upgrades	CNYX75			\$ 150,000	\$ 6,386,400	\$ 5,159,500	\$ 1,709,900	\$ -	\$ 13,405,800		
Ball Hill-Metering/RTU/Relay Upgrades Reimbursable Porti	CNYX75R			\$ (150,000)	\$ (6,386,400)	\$ (5,159,500)	\$ (1,709,900)	\$ -	\$ (13,405,800)		
Cape Vincent Wind-RTU/Metering/Relay upgrades	CNYX60			\$ 75,000	\$ 2,730,000	\$ -	\$ -	\$ -	\$ 2,805,000		
Cape Vincent Wind-RTU/Metering/Relay upgrades-Reimbur	CNYX60R			\$ (75,000)	\$ (2,730,000)	\$ -	\$ -	\$ -	\$ (2,805,000)		
Clayton Wind-Loop in, Loop-out	CNYX70			\$ 350,000	\$ 2,000,000	\$ -	\$ -	\$ -	\$ 2,350,000		
Clayton Wind-Loop in, Loop-out Reimbursable portion	CNYX70R			\$ (350,000)	\$ (2,000,000)	\$ -	\$ -	\$ -	\$ (2,350,000)		
Clayton Wind-RTU/Metering/Relay upgrades	CNYX71			\$ 320,000	\$ 1,000,000	\$ -	\$ -	\$ -	\$ 1,320,000		
Clayton Wind-RTU/Metering/Relay upgrades-Reimbursable	CNYX71R			\$ (320,000)	\$ (1,000,000)	\$ -	\$ -	\$ -	\$ (1,320,000)		
EDGE - Line Relocation	CNYX82			\$ 5,200,000	\$ -	\$ -	\$ -	\$ -	\$ 5,200,000		
EDGE - Line Relocation, Reimbursable Portion	CNYX82R			\$ (5,200,000)	\$ -	\$ -	\$ -	\$ -	\$ (5,200,000)		

Spending Rationale	Project Name	Project#	FY13	FY14	FY15	FY16	FY17	TOTAL	
Northeast Region Reinforcement	Everpower Allegany - line tap	CNYX78	\$ 100,000	\$ 800,000	\$ 500,000	\$ 100,000	\$ -	\$ 1,500,000	
	Everpower Allegany - Substation	CNYX79	\$ 250,000	\$ 3,000,000	\$ 2,500,000	\$ 50,000	\$ -	\$ 5,800,000	
	Everpower Allegany - Substation- Reimbursable Portion	CNYX79R	\$ (250,000)	\$ (3,000,000)	\$ (2,500,000)	\$ (50,000)	\$ -	\$ (5,800,000)	
	Everpower Allegany -line tap Reimbursable Portion	CNYX78R	\$ (100,000)	\$ (800,000)	\$ (500,000)	\$ (100,000)	\$ -	\$ (1,500,000)	
	Green Power-Cody Rd-loop in,loop out	CNYX68	\$ -	\$ -	\$ 310,000	\$ 229,000	\$ -	\$ 539,000	
	Green Power-Cody Rd-loop in,loop out Reimb Portion	CNYX68R	\$ -	\$ -	\$ (310,000)	\$ (229,000)	\$ -	\$ (539,000)	
	Green Power-Cody Rd-RTU, metering	CNYX69	\$ -	\$ -	\$ 1,100,000	\$ 520,000	\$ -	\$ 1,620,000	
	Green Power-Cody Rd-RTU, metering Reimb Portion	CNYX69R	\$ -	\$ -	\$ (1,100,000)	\$ (520,000)	\$ -	\$ (1,620,000)	
	New Grange Wind-Loop in, Loop-out	CNYX65	\$ -	\$ 530,000	\$ 500,000	\$ -	\$ -	\$ 1,030,000	
	New Grange Wind-Loop in, Loop-out Reimbursable portion	CNYX65R	\$ -	\$ (530,000)	\$ (500,000)	\$ -	\$ -	\$ (1,030,000)	
	New Grange Wind-RTU/Metering/Relay upgrades	CNYX66	\$ -	\$ 670,000	\$ 1,830,000	\$ 400,000	\$ -	\$ 2,900,000	
	New Grange Wind-RTU/Metering/Relay upgrades-Reimburs	CNYX66R	\$ -	\$ (670,000)	\$ (1,830,000)	\$ (400,000)	\$ -	\$ (2,900,000)	
	Nine Mile 2 Uprate	C39171	\$ 166,000	\$ 21,000	\$ 139,000	\$ -	\$ -	\$ 326,000	
	Nine Mile 2 Uprate Reimb Portion	C39171R	\$ (166,000)	\$ (21,000)	\$ (139,000)	\$ -	\$ -	\$ (326,000)	
	Ripley-Westfield - loop in,loop out	CNYX81	\$ 210,000	\$ 500,000	\$ 500,000	\$ -	\$ -	\$ 1,210,000	
	Ripley-Westfield - Substation	CNYX77	\$ 250,000	\$ 5,000,000	\$ 2,200,000	\$ 100,000	\$ -	\$ 7,550,000	
	Ripley-Westfield - Substation- Reimbursable Portion	CNYX77R	\$ (250,000)	\$ (5,000,000)	\$ (2,200,000)	\$ (100,000)	\$ -	\$ (7,550,000)	
	Ripley-Westfield-loop in,loop out Reimbursable Portion	CNYX81R	\$ (210,000)	\$ (500,000)	\$ (500,000)	\$ -	\$ -	\$ (1,210,000)	
	St Lawrence Wind-Loop in, Loop-out	CNYX55	\$ 100,000	\$ 900,000	\$ -	\$ -	\$ -	\$ 1,000,000	
	St Lawrence Wind-Loop in, Loop-out Reimbursable Portion	CNYX55R	\$ (100,000)	\$ (900,000)	\$ -	\$ -	\$ -	\$ (1,000,000)	
	St Lawrence Wind-RTU/Metering/Relay upgrades	CNYX56	\$ 600,000	\$ 1,600,000	\$ -	\$ -	\$ -	\$ 2,200,000	
	St Lawrence Wind-RTU/Metering/Relay upgrades-Reimburs	CNYX56R	\$ (600,000)	\$ (1,600,000)	\$ -	\$ -	\$ -	\$ (2,200,000)	
	Tug Hill Wind-Loop in, Loop-out	CNYX61	\$ -	\$ 241,500	\$ 324,000	\$ 20,200	\$ -	\$ 585,700	
	Tug Hill Wind-Loop in, Loop-out Reimbursable portion	CNYX61R	\$ -	\$ (241,500)	\$ (324,000)	\$ (20,200)	\$ -	\$ (585,700)	
	Tug Hill Wind-RTU/Metering/Relay upgrades	CNYX62	\$ -	\$ 564,500	\$ 1,083,000	\$ 211,000	\$ -	\$ 1,858,500	
	Tug Hill Wind-RTU/Metering/Relay upgrades-Reimbursable	CNYX62R	\$ -	\$ (564,500)	\$ (1,083,000)	\$ (211,000)	\$ -	\$ (1,858,500)	
	WestHill Wind-Loop in-loop out	CNYX49	\$ 100,000	\$ 372,500	\$ -	\$ -	\$ -	\$ 472,500	
	WestHill Wind-Loop in-loop out Reimbursable Portion	CNYX49R	\$ (100,000)	\$ (372,500)	\$ -	\$ -	\$ -	\$ (472,500)	
	WestHill Wind- RTU/metering	CNYX50	\$ 70,000	\$ 600,000	\$ -	\$ -	\$ -	\$ 670,000	
	WestHill Wind-RTU/metering Reimbursable Portion	CNYX50R	\$ (70,000)	\$ (600,000)	\$ -	\$ -	\$ -	\$ (670,000)	
	<b>Generation Total</b>			\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
	Other Statutory Regulatory	Eastover (was Turner) Road New Line Taps - Part of NERR	C31419	\$ 252,000	\$ 5,000,000	\$ 550,000	\$ -	\$ -	\$ 5,802,000
		Eastover Road New 230-115 KV Station (Part of NERR)	C31326	\$ 2,500,228	\$ 13,995,958	\$ 4,460,097	\$ -	\$ -	\$ 20,956,283
Mohican Battenkill #15 Rebuild Reconnector		C34528	\$ 1,812,000	\$ 8,004,840	\$ 16,506,960	\$ 3,852,000	\$ -	\$ 30,175,800	
Reactive Comp Prog in NE Region NRRP		C35773	\$ -	\$ 200,000	\$ 1,800,000	\$ -	\$ 200,000	\$ 2,200,000	
Reconductoring 115KV NE Region NRRP		C35771	\$ -	\$ 1,000,000	\$ 1,000,000	\$ 4,700,000	\$ 8,800,000	\$ 15,500,000	
Spier Rotterdam New Line - Line 302, 1, and tap		C31418	\$ 37,310,000	\$ 16,180,000	\$ -	\$ -	\$ -	\$ 53,490,000	
Sta Work to Suppt New Spier-Ridm		C40346	\$ 22,000	\$ -	\$ -	\$ -	\$ -	\$ 22,000	
FAA Obstruction Lighting/Marking		C27954	\$ 500,000	\$ -	\$ -	\$ 8,552,000	\$ 9,000,000	\$ 128,146,083	
FAA Obstruction Lighting - Central		C40703	\$ 45,000	\$ -	\$ -	\$ -	\$ -	\$ 45,000	
FAA Obstruction Lighting - East		C40704	\$ 75,000	\$ -	\$ -	\$ -	\$ -	\$ 75,000	
Hudson River Crossing Permit		C41449	\$ 530,000	\$ -	\$ -	\$ -	\$ -	\$ 530,000	
Interconnection Meter Investment Prgm Co 36 (NYISO)		C35267	\$ 5,119,700	\$ 1,388,300	\$ -	\$ -	\$ -	\$ 6,508,000	
Robin Steel - Roberts Rd. 163 Removal		C41352	\$ 50,000	\$ -	\$ -	\$ -	\$ -	\$ 50,000	
Porter 230kV - Upgrade/DiscpT's		C36866	\$ -	\$ 250,000	\$ 1,000,000	\$ 5,000,000	\$ 9,000,000	\$ 15,250,000	
<b>Other Statutory Regulatory Total</b>		\$ 6,319,700	\$ 1,638,300	\$ 1,000,000	\$ 5,000,000	\$ 9,000,000	\$ 22,958,000		
Reserve - Statutory Regulatory	CNYX31SR	\$ (8,663,229)	\$ (8,116,908)	\$ (2,396,796)	\$ (2,424,053)	\$ (3,817,627)	\$ (25,418,614)		
<b>Reserve - Statutory Regulatory Total</b>		\$ (8,663,229)	\$ (8,116,908)	\$ (2,396,796)	\$ (2,424,053)	\$ (3,817,627)	\$ (25,418,614)		
RTU Strategy	C03772	\$ 3,900,180	\$ -	\$ -	\$ -	\$ -	\$ 3,900,180		
RTU Replacements NERC, EMS, Obsolescence	C03772	\$ 3,900,180	\$ -	\$ -	\$ -	\$ -	\$ 3,900,180		
Porter 115 kV Upgrades	C28686	\$ 1,128,000	\$ 11,092,000	\$ 10,093,000	\$ 811,000	\$ -	\$ 23,124,000		
Station NPCC Upgrade	C28705	\$ 12,700,000	\$ 11,100,000	\$ 2,250,000	\$ -	\$ -	\$ 26,050,000		
Upgrade 115 kV Clay Sub - Central Division		\$ 13,828,000	\$ 22,192,000	\$ 12,343,000	\$ 811,000	\$ -	\$ 49,174,000		
<b>Station NPCC Upgrade Total</b>		\$ 63,772,879	\$ 68,647,190	\$ 50,614,461	\$ 26,938,947	\$ 29,182,373	\$ 239,155,849		
Frankhauser New Station - T Line Wo	C30744	\$ 299,880	\$ 379,652	\$ -	\$ -	\$ -	\$ 679,532		
Frankhauser New Station - T Sub Wor	C34427	\$ -	\$ 120,000	\$ -	\$ -	\$ -	\$ 120,000		
<b>Load Total</b>		\$ 299,880	\$ 499,652	\$ -	\$ -	\$ -	\$ 799,532		

Transmission Capital Investment Plan FY13 - FY17 (Revision for Rebudget)

Accepted Adjustments Reflected

Spending Rationale	Program	Project#	FY13	FY14	FY15	FY16	FY17	TOTAL
Other Syst Capacity & Performance	115 kV capacitor banks at Huntley	C37522	\$ 979,400	\$ 72,100	\$ -	\$ -	\$ -	\$ 1,051,500
	Bennett Rd Line Supply Change	C43739	\$ 105,000	\$ 35,000	\$ -	\$ -	\$ -	\$ 140,000
	BP76 Relay Upgrade	C39382	\$ 450,000	\$ -	\$ -	\$ -	\$ -	\$ 450,000
	Colton BrownsFalls 1 Load Brk Atch	C34546	\$ 213,500	\$ -	\$ -	\$ -	\$ -	\$ 213,500
	Dunkirk Temp Cap Banks	C43738	\$ 100,000	\$ -	\$ -	\$ -	\$ -	\$ 100,000
	Fourth Elm 230-23kV Bank (N-1-1)	CNYPL14	\$ -	\$ -	\$ -	\$ -	\$ 110,408	\$ 110,408
	Fourth Sawyer 230-23kV Bank (N-1-1)	CNYPL13	\$ 3,500,000	\$ 2,000,000	\$ -	\$ -	\$ -	\$ 5,500,000
	Gardenville Cap Banks	C43735	\$ 4,000,000	\$ 1,000,000	\$ -	\$ -	\$ -	\$ 5,000,000
	Huntley Bus Tie	C43737	\$ -	\$ -	\$ -	\$ -	\$ 110,408	\$ 110,408
	Inghams Station Revitalization	CNYPL3	\$ -	\$ -	\$ -	\$ -	\$ 40,000	\$ 40,000
	Installation of 115 kV Mobile Substation connection at Brent	CNYPL11-5	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
	Lowville Automated 115 kV Switches	C32259	\$ 178,710	\$ -	\$ -	\$ -	\$ -	\$ 178,710
	New Buffalo Station 42 T-Line	C40943	\$ 25,000	\$ 436,000	\$ 605,000	\$ -	\$ -	\$ 1,066,000
	New Buffalo Station 42 T-Sub	C40944	\$ 25,000	\$ 724,000	\$ 983,000	\$ -	\$ -	\$ 1,732,000
	Ogden Brook 115kV CS and Bus SW	C36026	\$ 241,900	\$ -	\$ -	\$ -	\$ -	\$ 241,900
	Packard Bus Tie	C43736	\$ 1,000,000	\$ 2,000,000	\$ -	\$ -	\$ -	\$ 3,000,000
	Replace overhauled 115kV breakers at Central and Mohawk	CNYPL26	\$ 990,000	\$ 574,000	\$ 941,000	\$ 751,000	\$ 1,622,650	\$ 4,878,650
	Replace overhauled 115kV breakers at Maplewood-CNYPL2	C39863	\$ 182,000	\$ -	\$ -	\$ -	\$ -	\$ 182,000
	Station #55 Line Supply Change	C43741	\$ 140,000	\$ 70,000	\$ -	\$ -	\$ -	\$ 210,000
	Station #139 Line Supply Change	C43740	\$ 280,000	\$ 70,000	\$ -	\$ -	\$ -	\$ 350,000
	Syracuse Area Reconductoring	CNYPL28	\$ 200,000	\$ 200,000	\$ 2,000,000	\$ 13,000,000	\$ 927,428	\$ 16,327,428
	Trinity UG Pumphouse	C11318	\$ 120,000	\$ 420,000	\$ 420,000	\$ -	\$ -	\$ 960,000
	TRV Mitigation-NY	C36071	\$ 385,740	\$ -	\$ -	\$ -	\$ -	\$ 385,740
	Upgrade Breakers at Scriba Sub - Central Division	C28708	\$ 1,236,150	\$ -	\$ -	\$ -	\$ -	\$ 1,236,150
	Upgrade Niagara-Packard #195	C29945	\$ 1,169,000	\$ 2,494,000	\$ 1,100,000	\$ -	\$ -	\$ 4,763,000
	Westzel Rd. Substation T-Line	C36983	\$ 50,000	\$ 1,560,000	\$ 60,000	\$ -	\$ -	\$ 1,670,000
<b>Other Syst Capacity &amp; Performance Total</b>			\$ 15,571,400	\$ 11,655,100	\$ 6,109,000	\$ 13,751,000	\$ 2,921,303	\$ 50,007,803
Overhead Line Refurbishment Program - System	Browns Falls-Taylorville 3-4 ACR	C24359	\$ 250,000	\$ 250,000	\$ 3,500,000	\$ 5,800,000	\$ -	\$ 9,800,000
	Coffeen-Lighthouse Hill 5, T2120 ACR	C24360	\$ 5,267,000	\$ 130,000	\$ -	\$ -	\$ -	\$ 5,397,000
<b>Overhead Line Refurbishment Program - System Capacity &amp; Performance Total</b>			\$ 5,517,000	\$ 380,000	\$ 3,500,000	\$ 5,800,000	\$ -	\$ 15,197,000
Reliability Criteria Compliance	Construct Southwest Sta (line work)	C24016	\$ 35,000	\$ 100,000	\$ 500,000	\$ 750,000	\$ 350,000	\$ 1,735,000
	Construct Southwest Station, part of SG075	C24015	\$ 1,000,000	\$ 3,500,000	\$ 24,550,000	\$ 16,700,000	\$ 500,000	\$ 46,250,000
	Dunkirk Second Bus Tie- Line, part of SG075	C31460	\$ -	\$ -	\$ -	\$ -	\$ 1,246,507	\$ 1,301,507
	Dunkirk Second Bus Tie- Station, part of SG075	C31459	\$ -	\$ -	\$ -	\$ 150,000	\$ 1,183,575	\$ 1,333,575
	Homier Hill 115kV Capacitor Banks, Part of SG075	C31457	\$ 1,255,000	\$ 515,000	\$ -	\$ -	\$ -	\$ 1,770,000
	Reconductoring portions of 54 and 181, part of SG075	C31463	\$ -	\$ -	\$ 85,000	\$ 100,000	\$ -	\$ 185,000
	Reconductoring of line #171	C24017	\$ 75,000	\$ 100,000	\$ 4,500,000	\$ 500,000	\$ -	\$ 5,175,000
	Second 115kV bus tie at Lockport, part of SG075	C31482	\$ 100,000	\$ 675,000	\$ -	\$ -	\$ -	\$ 775,000
	Upgrade Batavia South 115 kV Bus	C31479	\$ 25,000	\$ -	\$ -	\$ -	\$ -	\$ 25,000
	West Golah 115 kV substation	CNYPL37	\$ -	\$ 1,000,000	\$ 3,000,000	\$ 3,000,000	\$ -	\$ 7,000,000
	Second 115kV bus tie at Montimer	CNYPL38	\$ 100,000	\$ 675,000	\$ -	\$ -	\$ -	\$ 775,000
<b>Reliability Criteria Compliance Total</b>			\$ 2,590,000	\$ 6,565,000	\$ 32,635,000	\$ 21,255,000	\$ 3,280,082	\$ 66,325,082
Reserve - System Capacity & Performance	Capital Reserve - System Capacity & Performance	CNYX31ISCP	\$ (1,641,878)	\$ (1,707,925)	\$ (1,970,516)	\$ (3,437,165)	\$ (925,646)	\$ (9,683,130)
<b>Reserve - System Capacity &amp; Performance Total</b>			\$ (1,641,878)	\$ (1,707,925)	\$ (1,970,516)	\$ (3,437,165)	\$ (925,646)	\$ (9,683,130)
<b>System Capacity &amp; Performance Total</b>			\$ 22,336,402	\$ 17,391,827	\$ 40,273,484	\$ 37,368,835	\$ 5,275,739	\$ 122,646,287
<b>Grand Total Excluding Leeds Pleasant Valley, 3rd Line</b>			\$ 142,250,000	\$ 142,849,000	\$ 157,401,000	\$ 159,432,000	\$ 168,200,000	\$ 770,132,000
<b>Leeds Pleasant Valley, 3rd Line</b>			\$ 2,000,000	\$ 2,000,000	\$ 3,000,000	\$ 3,000,000	\$ 85,000,000	\$ 95,000,000
<b>Total Including Leeds</b>			\$ 144,250,000	\$ 144,849,000	\$ 160,401,000	\$ 162,432,000	\$ 253,200,000	\$ 865,132,000

Note 1  
Leeds Pleasant Valley, 3rd Line, is not included in the revenue requirement



**Rebuttal Testimony of the Electric Infrastructure and Operations Panel**

Exhibit \_\_ (EIOP-2R)

Distribution Capital Plan – Revised

Distribution Capital Investment Plan FY13 - FY17 Revised April 2012

Accepted Adjustments Reflected

Spending Rationale	Program	Project Name	Project #	FY13	FY14	FY15	FY16	FY17	TOTAL		
Statutory/Regulatory	Asset Condition I&M	06043 IE-NC-MH Program Placeholder	C32101		\$100,000	\$200,000	\$200,000	\$200,000	\$700,000		
		06045 IE-NC Duct Replac Placeholder	C32091	\$0	\$100,000	\$100,000	\$100,000	\$100,000	\$300,000		
		06047 IE-NE-Duct Replac Placeholder	C32093	\$0	\$100,000	\$100,000	\$100,000	\$100,000	\$300,000		
		06048 IE-NE-MH-Program-Placeholder	C32103	\$0	\$100,000	\$200,000	\$200,000	\$200,000	\$700,000		
		06050 IE-NW-Duct replace Placeholder	C32095	\$0	\$100,000	\$100,000	\$100,000	\$100,000	\$400,000		
		06051 IE-NW-MH Program Placeholder	C32102	\$0	\$200,000	\$200,000	\$200,000	\$200,000	\$800,000		
		Asset Condition I&M Total		\$0	\$700,000	\$900,000	\$900,000	\$700,000	\$3,200,000		
		Blanket	Blanket	05497 Cent NY-Dist-3rd Party Atch Blanket	CNC022	\$101,000	\$104,000	\$107,000	\$110,000	\$113,000	\$535,000
				05501 Cent NY-Dist-Land/Rights Blanket	CNC009	\$1,513,000	\$1,554,000	\$1,596,000	\$1,639,000	\$1,683,000	\$7,985,000
				05503 Cent NY-Dist-Meter Blanket	CNC004	\$1,161,000	\$1,245,000	\$1,325,000	\$1,438,000	\$1,535,000	\$6,726,000
05504 Cent NY-Dist-New Bus-Comm Blanket	CNC011			\$3,873,000	\$4,047,000	\$4,325,000	\$4,597,000	\$4,886,000	\$21,728,000		
05505 Cent NY-Dist-New Bus-Resid Blanket	CNC010			\$8,463,000	\$8,929,000	\$9,922,000	\$10,435,000	\$10,974,000	\$48,723,000		
05506 Cent NY-Dist-Public Require Blanket	CNC013			\$937,000	\$974,000	\$1,040,000	\$1,105,000	\$1,174,000	\$5,230,000		
05508 Cent NY-Dist-St Light Blanket	CNC012			\$3,407,000	\$3,523,000	\$3,662,000	\$3,777,000	\$3,896,000	\$18,265,000		
05808 East NY-Dist-3rd Party Atch Blanket	CNE022			\$110,000	\$113,000	\$116,000	\$119,000	\$122,000	\$580,000		
05815 East NY-Dist-Meter Blanket	CNE004			\$703,000	\$754,000	\$816,000	\$871,000	\$930,000	\$4,074,000		
05816 East NY-Dist-New Bus-Comm Blanket	CNE011			\$3,297,000	\$3,741,000	\$4,073,000	\$4,410,000	\$4,775,000	\$20,296,000		
05817 East NY-Dist-New Bus-Resid Blanket	CNE010			\$7,523,000	\$8,525,000	\$9,261,000	\$10,017,000	\$10,835,000	\$46,161,000		
05818 East NY-Dist-Public Require Blanket	CNE013			\$1,145,000	\$1,190,000	\$1,271,000	\$1,351,000	\$1,436,000	\$6,393,000		
05820 East NY-Dist-St Light Blanket	CNE012			\$1,887,000	\$1,951,000	\$2,028,000	\$2,092,000	\$2,158,000	\$10,116,000		
06282 NiMo Meter Purchases	CN3604			\$4,280,000	\$4,540,000	\$4,900,000	\$5,145,000	\$5,300,000	\$24,165,000		
06283 NiMo Transformer Purchases	CN3620			\$26,616,000	\$28,213,000	\$30,471,000	\$31,995,000	\$32,500,000	\$149,795,000		
06892 West NY-Dist-3rd Party Atch Blanket	CNW022			\$100,000	\$103,000	\$106,000	\$109,000	\$112,000	\$530,000		
06897 West NY-Dist-Land/Rights Blanket	CNW009			\$513,000	\$527,000	\$541,000	\$556,000	\$571,000	\$2,708,000		
06899 West NY-Dist-Meter Blanket	CNW004			\$925,000	\$992,000	\$1,073,000	\$1,146,000	\$1,223,000	\$5,359,000		
06900 West NY-Dist-New Bus-Comm Blanket	CNW011			\$3,873,000	\$4,047,000	\$4,406,000	\$4,771,000	\$5,166,000	\$22,263,000		
06901 West NY-Dist-New Bus-Resid Blanket	CNW010			\$5,328,000	\$5,558,000	\$6,038,000	\$6,531,000	\$7,064,000	\$30,519,000		
06902 West NY-Dist-Public Require Blanket	CNW013			\$963,000	\$1,001,000	\$1,089,000	\$1,179,000	\$1,276,000	\$5,508,000		
06904 West NY-Dist-St Light Blanket	CNW012			\$3,199,000	\$3,308,000	\$3,438,000	\$3,546,000	\$3,658,000	\$17,149,000		
Blanket Total				\$79,917,000	\$84,939,000	\$91,626,000	\$96,939,000	\$101,387,000	\$454,808,000		
Inspection & Maintenance	Inspection & Maintenance			05999 I&M-NC D-Line OH Work From Insp	C26160	\$7,525,000	\$6,519,000	\$5,848,000	\$5,848,000	\$5,848,000	\$31,588,000
				06000 I&M-NC D-Line UG Work From Insp	C26163	\$833,000	\$833,000	\$833,000	\$833,000	\$833,000	\$4,165,000
				06002 I&M-NE D-Line OH Work From Insp	C26159	\$17,176,800	\$13,038,000	\$5,848,000	\$5,848,000	\$5,848,000	\$47,758,000
				06003 I&M-NE D-Line UG Work From Insp	C26162	\$650,000	\$833,000	\$833,000	\$833,000	\$833,000	\$3,982,000
		06005 I&M-NW D-Line OH Work From Insp	C26161	\$8,996,221	\$6,519,000	\$5,848,000	\$5,848,000	\$5,848,000	\$33,059,221		
		06006 I&M-NW D-Line UG Work From Insp	C26164	\$1,500,000	\$1,434,000	\$1,434,000	\$1,434,000	\$1,434,000	\$7,236,000		
		Inspection & Maintenance Total		\$36,681,021	\$29,176,000	\$20,644,000	\$20,644,000	\$20,644,000	\$127,789,021		
		New Business	New Business	05645 Crown Island Project	C33330	\$50,000	\$0	\$0	\$0	\$0	\$50,000
				05980 Helderberg Meadows URD, Phase 1	C31612	\$250,000	\$0	\$0	\$0	\$0	\$250,000
				06511 Reserve for New Business Commercial Unidentified Specifics	RESERVE 036_011 LINE	\$4,295,000	\$4,450,000	\$4,600,000	\$4,750,000	\$4,900,000	\$22,995,000
06512 Reserve for New Business Residential Unidentified Specifics	RESERVE 036_010 LINE			\$1,890,000	\$2,800,000	\$2,900,000	\$3,000,000	\$3,100,000	\$13,690,000		
06696 SU Hill Area Upgrades	CD0015			\$5,000	\$0	\$0	\$0	\$0	\$5,000		
09456 Colonie Country Club Estate URD, Phase 1	CD0055			\$165,000	\$0	\$0	\$0	\$0	\$165,000		
11461 Foxry Bogas Facility System Upgrades	CD0206			\$10,000	\$0	\$0	\$0	\$0	\$10,000		
11611 Foxbrook Line Extension, Redfield, NY	CD0276			\$120,000	\$0	\$0	\$0	\$0	\$120,000		
12803 Kildare Meadows URD, Brewerton, NY	CD0302			\$115,000	\$0	\$0	\$0	\$0	\$115,000		
12882 Faith Ridge URD - Baldwinsville, NY	CD0334			\$110,000	\$0	\$0	\$0	\$0	\$110,000		
15730 DOT Lemoyne Av & Factory Av OH relocation	CD0361			\$112,000	\$0	\$0	\$0	\$0	\$112,000		
17477 APP Pharmaceutical Expansion - DLine	PPM 17477			\$250,000	\$0	\$0	\$0	\$0	\$250,000		
17509 Buffalo Station 64 - New F6451	PPM 17509			\$750,000	\$0	\$0	\$0	\$0	\$750,000		
New Business Total				\$8,122,000	\$7,250,000	\$7,500,000	\$7,750,000	\$8,000,000	\$38,622,000		
Public Requirements	Public Requirements			05719 DOT Batchellerville Bridge	C34864	\$200,000	\$0	\$0	\$0	\$0	\$200,000
				05733 DOT PIN 1757.16 Erie Blvd	C35862	\$200,000	\$0	\$0	\$0	\$0	\$200,000
				05760 DOT-Beebe Road Niagara County	C35789	\$294,000	\$0	\$0	\$0	\$0	\$294,000
		05779 DOT R128 White Lk - McKeever Dist	C35027	\$5,000	\$5,000	\$40,000	\$245,000	\$0	\$290,000		
		06514 Reserve for Public Requirements Unidentified Specifics	RESERVE 036_013 LINE	\$7,050,017	\$9,120,458	\$9,360,000	\$9,355,000	\$9,800,000	\$44,685,475		
		07002 MV-Frankfort Municipal Route 5	C36848	\$156,962	\$20,542	\$0	\$0	\$0	\$177,504		

Spending Rationale	Program	Project Name	Project #	FY13	FY14	FY15	FY16	FY17	TOTAL
Statutory/Regulatory, Total	Public Requirements Total	07032 Lynch's Trailer Park	CD0008	\$175,000	\$0	\$0	\$0	\$0	\$175,000
		11256 DOT PIN 5460.28-Niagara Falls Reconstruction	CD0161	\$200,000	\$0	\$0	\$0	\$0	\$200,000
		11884 DOT Rt. 11/Main St., Gouverneur	CD0282	\$300,000	\$0	\$0	\$0	\$0	\$300,000
		11885 DOT Rt 56, Colton	CD0281	\$250,000	\$0	\$0	\$0	\$0	\$250,000
		Public Requirements Total		\$8,825,979	\$9,146,000	\$9,400,000	\$9,600,000	\$9,800,000	\$46,771,979
		S or R Other		\$490,000	\$0	\$0	\$0	\$0	\$490,000
		S or R Other Total		\$490,000	\$0	\$0	\$0	\$0	\$490,000
		Blanket		\$134,036,000	\$131,211,000	\$130,070,000	\$135,833,000	\$140,531,000	\$671,681,000
		Blanket		\$504,000	\$460,000	\$499,000	\$519,000	\$576,000	\$2,580,000
		Damage/Failure		\$1,022,000	\$973,000	\$1,012,000	\$1,051,000	\$1,172,000	\$5,230,000
Statutory/Regulatory, Total	Major Storms	04693 Cent NY-Dist-Subs Blanket	CNC002	\$419,000	\$399,000	\$415,000	\$431,000	\$481,000	\$2,145,000
		05206 West NY-Dist-Subs Blanket	CNC002	\$4,562,000	\$4,341,000	\$4,515,000	\$4,690,000	\$5,231,000	\$23,339,000
		05499 Cent NY-Dist-Damage/Failure Blanket	CNE014	\$6,584,000	\$6,265,000	\$6,515,000	\$6,769,000	\$7,549,000	\$33,682,000
		05810 East NY-Dist-Damage/Failure Blanket	CNE014	\$4,925,000	\$4,686,000	\$4,873,000	\$5,063,000	\$5,646,000	\$25,193,000
		06894 West NY-Dist-Damage/Failure Blanket	CNW014	\$18,016,000	\$17,144,000	\$17,829,000	\$18,523,000	\$20,657,000	\$92,169,000
		Blanket Total		\$155,000	\$0	\$0	\$0	\$0	\$155,000
		D/F Other		\$2,641,000	\$1,706,000	\$426,500	\$0	\$0	\$4,347,000
		D/F Other Total		\$55,000	\$660,000	\$426,500	\$0	\$0	\$1,141,500
		Major Storms		\$3,151,000	\$2,366,000	\$426,500	\$0	\$0	\$5,943,500
		Major Storms Total		\$518,000	\$536,000	\$555,000	\$575,000	\$586,000	\$2,770,000
Statutory/Regulatory, Total	Major Storms	06689 Storm Damage Distribution East Div.	C00328	\$518,000	\$536,000	\$555,000	\$575,000	\$586,000	\$2,770,000
		06690 Storm Damage-Dist-Cent Div	C12965	\$518,000	\$536,000	\$555,000	\$575,000	\$586,000	\$2,770,000
		05062 Reserve for Damage/Failure Unidentified Specifics & S	RESERVE 036_014 SUE	\$1,145,000	\$1,350,000	\$2,400,000	\$2,450,000	\$2,500,000	\$9,845,000
		06509 Reserve for Damage/Failure Unidentified Specifics & S	RESERVE 036_014 LINE	\$500,000	\$525,000	\$850,500	\$850,000	\$850,000	\$3,575,500
		TBD Total		\$1,645,000	\$1,875,000	\$3,250,500	\$3,300,000	\$3,350,000	\$13,420,500
		Blanket Total		\$24,366,000	\$22,993,000	\$23,171,000	\$23,548,000	\$25,785,000	\$119,863,000
		Capacity Planning		\$506,000	\$523,000	\$542,000	\$559,000	\$576,000	\$2,708,000
		Capacity Planning		\$1,575,000	\$1,020,000	\$1,057,000	\$1,103,000	\$1,197,000	\$6,552,000
		Capacity Planning		\$394,000	\$407,000	\$422,000	\$435,000	\$448,000	\$2,106,000
		Capacity Planning		\$1,594,000	\$1,031,000	\$1,069,000	\$1,116,000	\$1,181,000	\$6,628,000
Statutory/Regulatory, Total	Capacity Planning	06898 West NY-Dist-Load Relief Blanket	CNW016	\$619,000	\$639,000	\$662,000	\$682,000	\$703,000	\$3,305,000
		06903 West NY-Dist-Reliability Blanket	CNW015	\$3,458,000	\$2,238,000	\$2,321,000	\$2,422,000	\$3,946,000	\$14,385,000
		04748 Duguid Second Transformer	C32497	\$8,146,000	\$5,858,000	\$6,073,000	\$6,317,000	\$9,288,000	\$35,682,000
		04792 Frankhauser New Station - T Sub Work	C36520	\$405,000	\$855,000	\$1,350,000	\$0	\$0	\$2,610,000
		04793 Frankhauser-115-13.2KV-Bus & Bkrs	C28931	\$300,000	\$2,000,000	\$730,000	\$0	\$0	\$3,030,000
		04812 Harris Second Transformer	C28931	\$20,000	\$605,000	\$485,000	\$0	\$0	\$1,110,000
		04827 Inman Rd -Add M/C & 13.2KV Bus work	C28770	\$203,846	\$1,048,077	\$2,153,846	\$0	\$0	\$3,405,769
		04828 Install 2nd Transformer - Inman Rd	C35270	\$900,000	\$0	\$0	\$0	\$0	\$900,000
		04895 N Syracuse Capacity Inc	C28831	\$380,000	\$3,610,000	\$930,000	\$0	\$0	\$4,920,000
		04903 NC Starr Rd Second Xfrm-13kv Switch	C32368	\$10,000	\$590,000	\$600,000	\$150,000	\$0	\$1,350,000
Statutory/Regulatory, Total	Capacity Planning	04904 NC Starr Rd. Second Xfrm	C32503	\$750,000	\$2,250,000	\$2,000,000	\$0	\$0	\$5,000,000
		04950 NW N Collins Repl T1 Xfrm	C32313	\$100,000	\$603,462	\$10,000	\$807,692	\$0	\$1,513,154
		04951 NW Repl Egen Ctr Xfrm / LTC	C32331	\$150,000	\$150,000	\$600,000	\$0	\$0	\$900,000
		04953 NW Upgrade Panama Xfrm / Regs	C32306	\$500,000	\$500,000	\$0	\$0	\$0	\$1,000,000
		04989 Ogden Brook- install 13.2 KV s/gear	C34783	\$1,000,000	\$500,000	\$0	\$0	\$0	\$1,500,000
		04990 Ogdenbrook Sta - Add Ckt Sw & TB2	C32495	\$850,000	\$0	\$405,000	\$855,000	\$0	\$2,115,000
		04994 Paloma Second Transformer	C08153	\$105,000	\$110,000	\$115,000	\$120,000	\$125,000	\$575,000
		05011 PS&I Activity - New York	RESERVE 036_016 SUE	\$39,000	-\$11,000,000	-\$1,400,000	\$7,167,000	\$13,045,000	\$7,851,000
		05063 Reserve for Load Relief Unidentified Specifics & Sched	C32430	\$0	\$42,000	\$412,500	\$0	\$0	\$454,500
		05139 Station 214 - Install TB2	C29186	\$0	\$200,000	\$1,200,000	\$0	\$0	\$1,400,000
Statutory/Regulatory, Total	Capacity Planning	05194 W. Albion Transformer Addition	C32346	\$165,000	\$0	\$0	\$0	\$0	\$165,000
		06224 Youngstown 88 - Station Rebuild	C29049	\$250,000	\$200,000	\$700,000	\$0	\$0	\$900,000
		05283 Altica12-Rebuild,Xfer F1263 to 0158	C26379	\$0	\$0	\$0	\$0	\$0	\$250,000
		06473 Canajoharie 03122 - Rebuild Rt 162	C00329	\$830,000	\$0	\$0	\$0	\$0	\$830,000

Spending Rationale	Program	Project Name	Project #	FY13	FY14	FY15	FY16	FY17	TOTAL
		05866 F13861 Extend & Transfer to F23251	C26557	\$60,000	\$0	\$0	\$0	\$0	\$60,000
		05867 F13862 Extend & Transfer to F23255	C26558	\$60,000	\$0	\$0	\$0	\$0	\$60,000
		05878 F7654 - Extend & Transfer to 23251	C26559	\$60,000	\$0	\$0	\$0	\$0	\$60,000
		05920 Frankhauser New Station - Line Work	C28929	\$118,000	\$2,003,000	\$236,000	\$0	\$0	\$2,357,000
		06127 Liberty 9490 - replace gateway	C28786	\$130,000	\$0	\$0	\$0	\$0	\$130,000
		06243 N Syracuse Sub Getaways	C30506	\$10,000	\$2,917,000	\$110,000	\$0	\$0	\$3,037,000
		06299 Northville 52 - Convert N. Shore Rd	C07477	\$3,000	\$0	\$0	\$0	\$0	\$3,000
		06393 Ogden Brook - Install new feeders	C32598	\$500,000	\$0	\$0	\$0	\$0	\$500,000
		06510 Reserve for Load Relief Unidentified Specifics & Sched	RESERVE 036_016 LINE	\$2,000,000	-\$6,000,000	\$0	\$750,000	\$4,500,000	-\$2,750,000
		06675 Station 214 - New F21466/67	C29187	\$0	\$30,000	\$1,500,000	\$1,500,000	\$0	\$3,030,000
		06981 Sanborn Substation Rebuild (D-Sub)	C36985	\$600,000	\$2,680,000	\$130,000	\$0	\$0	\$3,410,000
		06990 PLACEHOLDER--Duguid Second Transformer (D-line)	C36857	\$0	\$1,925,000	\$875,000	\$175,000	\$0	\$2,975,000
		09227 Walmore 217 Contingency Load Relief	C36566	\$0	\$20,962	\$86,154	\$0	\$0	\$107,116
		09229 Wolf Rd. 34452 UG Cable Replacement	C36470	\$175,000	\$1,000,000	\$0	\$0	\$0	\$1,175,000
		09234 Bifo Sta 139 - Replace Transformers	C36639	\$0	\$1,210,000	\$550,000	\$110,000	\$0	\$1,870,000
		09235 Bifo Sta 55 - Replace Transformers	C36644	\$0	\$0	\$330,000	\$1,210,000	\$0	\$1,540,000
		09236 Bridge St. Second Transformer	C36185	\$0	\$250,000	\$1,500,000	\$250,000	\$0	\$2,000,000
		09239 Buffalo Sta 56- upgrade 4 Ximirs	C36502	\$400,000	\$1,511,058	\$131,010	\$134,615	\$0	\$2,176,683
		09249 Delphi Transformer Rating Increase	C36166	\$0	\$605,000	\$275,000	\$55,000	\$0	\$935,000
		09263 Military Road 210 - Install TB#2	C36056	\$0	\$0	\$500,000	\$3,000,000	\$0	\$3,500,000
		09273 Shawnee Road 76 (DSub)	C36059	\$318,558	\$2,709,279	\$1,665,385	\$257,596	\$0	\$4,950,818
		09277 Walmore 217 Load Relief (DSub)	C36579	\$160,000	\$250,000	\$0	\$0	\$0	\$410,000
		09279 Wilson 93 Load Relief - Replace TB1	C35743	\$563,750	\$256,250	\$51,250	\$0	\$0	\$871,250
		11086 Ash St 12 kv Metalclad Replacement gateway cable	GD0134	\$30,000	\$225,000	\$0	\$0	\$0	\$255,000
		11196 Buffalo Station 38 - F3863 Relief	CD0252	\$50,000	\$0	\$0	\$0	\$0	\$50,000
		11197 Buffalo Station 46 & 44 - F4672/F4468 Relief	CD0253	\$195,000	\$0	\$0	\$0	\$0	\$195,000
		11201 Buffalo Station 38 - F3864 Relief	GD0321	\$453,725	\$0	\$0	\$0	\$0	\$453,725
		11323 Getaway upgrade overroded section	CD0341	\$108,000	\$0	\$0	\$0	\$0	\$108,000
		11354 East Norfolk 91361 line reconductoring	CD0358	\$102,000	\$0	\$0	\$0	\$0	\$102,000
		11358 Beech Ave Conversion Niagara Falls	C32751	\$0	\$207,843	\$203,039	\$0	\$0	\$410,882
		11361 8th St Conversion Niagara Falls	PPM 11361	\$0	\$51,961	\$0	\$0	\$0	\$51,961
		11380 Welch Ave Conversion Load Relief	PPM 11380	\$0	\$20,000	\$213,824	\$240,441	\$0	\$474,265
		11486 Starr Rd 33453/Tuller Hill 24651	PPM 11486	\$700,000	\$482,353	\$100,000	\$0	\$0	\$1,282,353
		11490 Inman 37095 -- Lisha Kill Road Conversion (4.16kV to	CD0209	\$250,000	\$0	\$0	\$0	\$0	\$250,000
		11744 Buffalo Station 40 - F4067 Relief	PPM 11744	\$0	\$0	\$0	\$98,353	\$0	\$98,353
		11838 2163 Load Relief	PPM 11838	\$20,000	\$137,212	\$0	\$0	\$0	\$157,212
		11886 Randall Rd - New station - M/C S/G & Cap Bank	PPM 11886	\$0	\$0	\$0	\$64,615	\$1,534,615	\$1,599,230
		11887 Randall Rd - New station - Dist getaways, etc	PPM 11887	\$50,000	\$347,000	\$347,000	\$347,000	\$50,000	\$1,141,000
		11933 Sodeman Rd Station - new station - M/C & cap bank	PPM 11933	\$0	\$0	\$0	\$394,615	\$405,000	\$799,615
		11943 Sodeman Rd - New station - dist getaways, reconducto	PPM 11943	\$50,000	\$430,000	\$1,383,077	\$1,604,231	\$40,000	\$3,507,308
		11956 Queensbury Station - Reroute getaways to new M/C S/	PPM 11956	\$0	\$0	\$20,000	\$363,654	\$393,750	\$777,404
		11958 McCrea Station - New station - Install M/C & cap bank	PPM 11958	\$0	\$0	\$30,000	\$600,288	\$646,875	\$1,277,163
		11959 McCrea Station - New station - Getaways, etc.	PPM 11959	\$0	\$20,000	\$303,077	\$328,846	\$0	\$651,923
		13238 Albion 8064 Getaway Reconductor	PPM 13238	\$0	\$0	\$0	\$46,302	\$0	\$46,302
		13245 South Livingston Relief - Station Work	PPM 13245	\$265,000	\$2,354,400	\$604,800	\$0	\$0	\$3,224,200
		13246 South Livingston relief - D-Line work	PPM 13246	\$265,000	\$1,940,200	\$504,000	\$0	\$0	\$2,709,200
		13249 NW North Eden Replace	PPM 13249	\$20,000	\$716,058	\$50,000	\$0	\$0	\$786,058
		13270 Albion Station 34.5kV cap bank installation	PPM 13270	\$693,000	\$76,000	\$0	\$0	\$0	\$769,000
		13280 Grooms Rd 34557 - Saratoga Rd Conversion (4.8 to 13	PPM 13280	\$0	\$187,500	\$0	\$0	\$0	\$187,500
		15713 Newtonville 30584 Load Relief	CD0388	\$75,000	\$0	\$0	\$0	\$0	\$75,000
		15714 Berry Road Distribution Line Cap installations	PPM 15714	\$155,000	\$8,400	\$0	\$0	\$0	\$163,400
		15715 Roberts Road Distribution Line Cap installations	PPM 15715	\$155,000	\$8,400	\$0	\$0	\$0	\$163,400
		15717 Bennett Road Distribution Line Cap installations	PPM 15717	\$250,000	\$0	\$0	\$0	\$0	\$250,000
		15744 PLACEHOLDER - Study for Dunkirk 34.5kV	PPM 15744	\$0	\$0	\$0	\$0	\$67,500	\$67,500
		15746 PLACEHOLDER -Study for Genesee North 34.5kV	PPM 15746	\$0	\$0	\$0	\$0	\$67,500	\$67,500
		17420 Rotterdam 13853 - Route 5S Conversion (4.16 / 13.2kV	PPM 17420	\$450,000	\$0	\$0	\$0	\$0	\$450,000

Spending Rationale	Program	Project Name	Project #	FY13	FY14	FY15	FY16	FY17	TOTAL
		17496 Baker St Distribution Line Cap Installations	CD0840	\$125,000					\$125,000
		17510 Grooms Rd 34457 - Rosemary Drive Conversion - 4.16 PPM 17510		\$225,000	\$0	\$0	\$0	\$0	\$225,000
		17511 - Buffalo Station 64 - South Grand Island Area Relief - PPM 17511		\$20,000	\$0	\$0	\$0	\$0	\$20,000
		17793 NR-Coffeen 76051 Gaffney St. Reconnector	PPM 17793	\$225,000					\$225,000
		17795 French Creek Station 56 - Transformer Replacement	PPM 17795	\$917,000					\$917,000
		17810 CR- Paloma 57 - Convert Schuyler St Ratio	CD0853	\$225,000					\$225,000
		17819 CR- Convert CR 57 on Whitaker 53	PPM 17819	\$625,000					\$625,000
		17827 CR- Rock Cut 53 Midland Ave conversion	PPM 17827	\$350,000					\$350,000
		17852 CR- W Monroe 51 CR 11 Conversion	PPM 17852	\$200,000					\$200,000
		17870 SW - Reconnector #6 Wire on Machias 1362 on State	PPM 17870	\$440,000					\$440,000
	Capacity Planning Total			\$14,969,879	\$22,503,415	\$22,439,962	\$20,945,248	\$20,875,240	\$101,733,744
	ERR	05273 Amsterdam 51/53 - Widow Susan Rd Area	C28835	\$250,000	\$250,000	\$0	\$0	\$0	\$500,000
		05305 Batavia 0155 - Knapp Rd 22651 Tie	C28719	\$200,000	\$0	\$0	\$0	\$0	\$200,000
		05547 Clinton 53 - Convert Ft Plain	C06698	\$69,000	\$0	\$0	\$0	\$0	\$69,000
		05882 F9753 Rebuild/Conv tie w/F21754	C28689	\$60,000	\$0	\$0	\$0	\$0	\$60,000
		06300 Northville 52 - EJ West 51 Tie	C29435	\$25,000	\$0	\$0	\$0	\$0	\$25,000
		06305 NR_ 81652 CoRte26 StepDown	C34803	\$50,000	\$0	\$0	\$0	\$0	\$50,000
		06441 Port Henry 51 - Convert Westport	C18991	\$500,000	\$0	\$0	\$0	\$0	\$500,000
		06657 St Johnsville - Sanders Road	C29439	\$185,000					\$185,000
		06731 Swann Rd F10552 tie with F10557	C28106	\$40,000	\$0	\$0	\$0	\$0	\$40,000
		11077 NR-Chasrn Falls 85251-Indian Lake/Mtn View Lake-Re	CD0088	\$300,000	\$0	\$0	\$0	\$0	\$300,000
		11105 NR-Lowville 77354-Pine Grove Rd-Overloaded Step-d	CD0476	\$436,471	\$0	\$0	\$0	\$0	\$436,471
		11600 MV Humphrey Rd Rebuild	CD0264	\$110,884					\$110,884
		11633 EJ West 51 - Scofield Rd. 53 Single Phase Tie	CD0256	\$95,000	\$0	\$0	\$0	\$0	\$95,000
		11914 UG Cable Replacements - NYS Lake Ontario State Par	CD0292	\$302,400	\$0	\$0	\$0	\$0	\$302,400
		11922 Brook Road 55 - Young Road Rebuild	CD0299	\$70,000	\$0	\$0	\$0	\$0	\$70,000
		12731 Middleburgh 51 - Relocate Route 30 Creek Crossing	CD0324	\$225,000	\$0	\$0	\$0	\$0	\$225,000
		12732 Middleburgh 51 - North Road Rebuild	CD0312	\$415,000	\$0	\$0	\$0	\$0	\$415,000
		12761 Port Henry 51 - Rebuild Route 9N from P148-158	CD0306	\$25,000	\$0	\$0	\$0	\$0	\$25,000
		12773 Port Henry 51 - Rebuild Route 9N from P195-205	CD0326	\$75,000	\$0	\$0	\$0	\$0	\$75,000
		12832 Center St 54 - Hyney Hill Road Rebuild	CD0357	\$122,500	\$0	\$0	\$0	\$0	\$122,500
		12834 Center St. 54 - Extend 3Ø on State Route 30A	CD0329	\$525,000	\$0	\$0	\$0	\$0	\$525,000
		12883 NR TI_ 81455 NYSRte12E Overloaded Step-down	CD0344	\$315,000	\$0	\$0	\$0	\$0	\$315,000
		12912 Delameter - F9354 Load Relief	CD0354	\$734,900	\$0	\$0	\$0	\$0	\$734,900
		13276 Hudson 08753 - Rhinebeck-Hudson Road - Reconnect	CD0372	\$185,000	\$0	\$0	\$0	\$0	\$185,000
		17419 Ashley 51 - Baldwin Corners Road Phase 1	CD0389	\$100,000	\$0	\$0	\$0	\$0	\$100,000
		17247 Schoharie 52 - State Route 443 Rebuild	CD0424	\$485,000					\$485,000
		17610 ERR Program Placeholder	PPM 17610	\$0	\$3,500,000	\$3,500,000	\$3,500,000	\$3,500,000	\$14,000,000
ERR Total				\$5,901,155	\$3,750,000	\$3,500,000	\$3,500,000	\$3,500,000	\$20,151,155
Heavily Loaded Transformer		06011 IE - NC Dist Transformer Upgrades	C14846	\$1,000,000	\$1,067,000	\$1,184,000	\$1,234,000	\$1,286,000	\$5,771,000
		06023 IE - NE Dist Transformer Upgrades - C15828	C15828	\$1,000,000	\$1,066,000	\$1,183,000	\$1,233,000	\$1,285,000	\$5,767,000
		06033 IE - NW Dist Transformer Upgrades	C10967	\$1,000,000	\$1,067,000	\$1,183,000	\$1,233,000	\$1,285,000	\$5,768,000
Heavily Loaded Transformer Total				\$3,000,000	\$3,200,000	\$3,550,000	\$3,700,000	\$3,856,000	\$17,306,000
New Business		05512 Center St 54 - Rebuild Route 5S	C29426	\$50,000	\$0	\$0	\$0	\$0	\$50,000
New Business Total				\$50,000	\$0	\$0	\$0	\$0	\$50,000
Overhead Distribution		FJ06016 IE - NC Side Tap Fusing	C15511	\$600,000	\$600,000	\$600,000	\$600,000	\$600,000	\$3,000,000
		06028 IE - NE Side Tap Fusing	C15510	\$600,000	\$600,000	\$600,000	\$600,000	\$600,000	\$3,000,000
		06038 IE - NW Side Tap Fusing	C15509	\$600,000	\$600,000	\$600,000	\$600,000	\$600,000	\$3,000,000
Overhead Distribution Fusing Total				\$1,800,000	\$1,800,000	\$1,800,000	\$1,800,000	\$1,800,000	\$9,000,000
Recloser		06014 IE - NC Recloser/Switch Installs	C13267	\$1,072,000	\$0	\$0	\$0	\$0	\$1,072,000
		06026 IE - NE Recloser/Switch Install	C13266	\$1,608,000	\$107,200	\$0	\$0	\$0	\$1,715,200
		06036 IE - NW Recloser/Switch Installs	C13268	\$804,000	\$0	\$0	\$0	\$0	\$804,000
Recloser Total				\$3,484,000	\$107,200	\$0	\$0	\$0	\$3,591,200
SC&P Other		04674 Buffalo/Albany/Flying Grounds/SwitchRpl	C33636	\$750,000	\$1,500,000	\$750,000	\$0	\$0	\$3,000,000
		05095 Schuylerville Station - Bus Changes	C35226	\$0	\$75,000	\$175,000	\$0	\$0	\$250,000
		05256 Albany Network Study Construction	CD0016	\$1,617,165	\$0	\$0	\$0	\$0	\$1,617,165
		05367 Brook Road 55/57 - Daniels Rd	C29425	\$216,000	\$0	\$0	\$0	\$0	\$216,000
		05399 Buffalo Station 03 - F0303 Removal	C36207	\$100	\$100	\$100	\$0	\$0	\$300

Spending Rationale	Program	Project Name	Project #	FY13	FY14	FY15	FY16	FY17	TOTAL
		05400 Buffalo Station 12 - Fdr Rem & Ties	C36208	\$25,000	\$100,000	\$100,000	\$0	\$0	\$225,000
		06341 NR-North Carriage 81652-53 Fdr Tie	C10693	\$0	\$150,000	\$750,000	\$0	\$0	\$900,000
		06755 Tonawanda - F7128 Removal	C36206	\$0	\$100	\$100	\$100	\$0	\$300
		06872 W Hamlin 8254 - Tie w/F8252 & F7458	C28715	\$350,000	\$0	\$0	\$0	\$0	\$350,000
		07003 MV-Kingsley Ave Convert 5KV	C36651	\$195,000	\$0	\$0	\$0	\$0	\$195,000
		09250 East Malloy- feeders and getaways	C36188	\$0	\$538,712	\$3,500,000	\$1,000,000	\$0	\$5,038,712
		09252 Fly Rd. Transformer Addition	C36189	\$0	\$356,346	\$503,462	\$46,587	\$0	\$906,395
		11147 Bethlehem 02158 - Juniper 44651 TIE (02158 Convert)	PPM 11147	\$0	\$300,000	\$0	\$0	\$0	\$300,000
		11318 Spier-Rotterdam Project - Dist relocations	CD0187	\$4,235,000	\$63,000	\$0	\$0	\$0	\$4,298,000
		11602 MV Mulholland Rd Convert to 13.2KV	CD0245	\$180,000	\$0	\$0	\$0	\$0	\$180,000
		13373 East Malloy transformer addition	PPM 13373	\$0	\$356,346	\$503,462	\$46,587	\$0	\$906,395
		13866 East Malloy- low side sub equipment	PPM 13866	\$0	\$314,423	\$1,098,462	\$526,154	\$0	\$1,939,039
		13999 Fly Rd Low side substation equipment	PPM 13999	\$0	\$167,692	\$236,923	\$21,923	\$0	\$426,538
		14031 Fly Rd Low side feeders/getaways	PPM 14031	\$0	\$446,481	\$1,674,615	\$731,135	\$0	\$2,852,231
		15685 Orangeville Substation - Modify Regulator Bank	PPM 15685	\$79,500	\$0	\$0	\$0	\$0	\$79,500
		17185 DLine - To expand Rock Cut Sub Retire Brighton 4KV	PPM 17185	\$200,000	\$719,231	\$100,000	\$0	\$0	\$1,019,231
		17513 Ruth Rd 38153 - Lisha Kill Rd Conversion	CD0563	\$162,500	\$0	\$0	\$0	\$0	\$162,500
		17515 Karter 31716 Conversion - New 13.2KV Tie	PPM 17515	\$0	\$150,000	\$0	\$0	\$0	\$150,000
		17516 Reynolds Rd 33455 Line Extension (34.5KV to 13.2KV)	PPM 17516	\$0	\$120,000	\$0	\$0	\$0	\$120,000
		17517 Buffalo Station 42 - Voltage Mitigation	CD0541	\$200,000	\$0	\$0	\$0	\$0	\$200,000
		17733 NR-Coffeen 76052 E Watertown 81756 Inner Loop F	CD0560	\$356,000	\$0	\$0	\$0	\$0	\$356,000
		SC&P Other Total		\$8,566,265	\$5,357,431	\$9,392,124	\$2,372,486	\$0	\$25,688,306
	Substation Relay/Protect	04615 Bethlehem L10, L14 Relay Upgrades	C36193	\$150,000	\$275,000	\$0	\$0	\$0	\$425,000
		04877 MikeCooperTASRelayReplacementCo38DXT	C34691	\$300,000	\$300,000	\$200,000	\$0	\$0	\$800,000
	Substation Relay/Protection Total			\$450,000	\$575,000	\$200,000	\$0	\$0	\$1,225,000
	Substation RTU	05027 REP - Dist Subs EMS RTU DNP Plan	C20173	\$250,000	\$250,000	\$150,000	\$150,000	\$150,000	\$950,000
		05028 REP - Dist Subs Without RTUS	C19881	\$2,500,000	\$2,500,000	\$2,500,000	\$2,500,000	\$2,500,000	\$12,500,000
		07037 Birch Ave Sub EMS Modifications	CD0009	\$50,000	\$0	\$0	\$0	\$0	\$50,000
	Substation RTU Total			\$2,800,000	\$2,750,000	\$2,650,000	\$2,650,000	\$2,650,000	\$13,500,000
	TBD	04752 Dxt Study Budgetary Reserve - NIMO - C31550	C31550	\$100,000	\$100,000	\$100,000	\$100,000	\$100,000	\$500,000
		05065 Reserve for Reliability Unidentified Specifics & Schedule	RESERVE 036_015 SUE	\$0	-\$1,500,000	-\$4,000,000	\$3,750,000	\$5,500,000	\$3,750,000
		06515 Reserve for Reliability Unidentified Specifics & Schedule	RESERVE 036_015 LINE	-\$6,725,299	\$999,954	\$724,914	\$3,149,266	\$4,224,760	\$2,373,595
	TBD Total			-\$6,625,299	-\$400,046	-\$3,175,086	\$6,999,266	\$9,824,760	\$8,623,595
	Arc Flash Mediation	18023 Arc Flash Mediation - 480V Spot Networks	PPM 18023	\$150,000	\$2,000,000	\$4,000,000	\$4,000,000	\$4,000,000	\$14,150,000
	Arc Flash Mediation Total			\$150,000	\$2,000,000	\$4,000,000	\$4,000,000	\$4,000,000	\$14,150,000
	System Capacity & Performance Total			\$42,692,000	\$47,501,000	\$50,430,000	\$52,284,000	\$55,794,000	\$248,701,000
	Asset Condition			\$100	\$0	\$0	\$0	\$0	\$100
	AC Other	04682 Canajoharie Sub Retirement	C29948	\$74,000	\$0	\$0	\$0	\$0	\$74,000
		04869 McBride Station - Retire 5KV Assets	C36209	\$100,000	\$100,000	\$100,000	\$100,000	\$0	\$400,000
		04970 NY Small Capital Items	C26760	\$13,000	\$0	\$0	\$0	\$0	\$13,000
		05215 White Lake Station Upgrades	C08435	\$25,000	\$0	\$0	\$0	\$0	\$25,000
		05475 Canajoharie D-Line Work	C28837	\$70,000	\$0	\$0	\$0	\$0	\$70,000
		06212 Middleburgh 52 - Kelsey Hill Road	C35083	\$18,000	\$0	\$0	\$0	\$0	\$18,000
		06543 Rock City Falls 40415 - Armer Road	C20071	\$425,000	\$0	\$0	\$0	\$0	\$425,000
		06623 Sharon 52 - Rebuild Routes 20 & 145	C06680	\$115,000	\$0	\$0	\$0	\$0	\$115,000
		07009 NR-Samaritan Keep Nursing Home	C36846	\$108,000	\$432,000	\$0	\$0	\$0	\$540,000
		09221 Market Hill Convert Load	C36638	\$50,000	\$0	\$0	\$0	\$0	\$50,000
		09228 Warrensburg 51 - E Schroon River Rd	C35271	\$0	\$280,000	\$385,000	\$35,000	\$0	\$700,000
		09242 Carthage Replacoe Struct Footings	C36183	\$950,000	\$750,000	\$0	\$0	\$0	\$1,700,000
		09254 Hoag Station Rehab	C36050	\$50,000	\$0	\$0	\$0	\$0	\$50,000
		09258 Lockport Road 216 - Install TB#2	C36057	\$100,000	\$0	\$0	\$0	\$0	\$100,000
		10829 Distribution Transfers on Line #308 Rebuild	CD0082	\$325,000	\$0	\$0	\$0	\$0	\$325,000
		11122 Greenbush 07854 - Best Road Conversion	CD0152	\$100	\$100	\$0	\$100	\$0	\$200
		11257 Buffalo Station 12 - 25 Cycle Retirement	PPM 11257	\$50,000	\$100	\$0	\$0	\$0	\$150
		11258 Buffalo Station 14 - 25 Cycle Retirement	PPM 11258	\$50,000	\$100	\$0	\$0	\$0	\$150
		11299 Buffalo Station 122 Rebuild - Sla	PPM 11299	\$10,000	\$0	\$0	\$0	\$0	\$10,000
		11300 Buffalo Station 122 Rebuild - Line	PPM 11300	\$5,000	\$0	\$0	\$0	\$0	\$5,000
		11314 Amsterdam 54 - Langley Rd 30 Extension	CD0169	\$650,000	\$475,000	\$0	\$0	\$0	\$1,125,000
		11458 MV- Poland 62258 Route 8 Reconnector	PPM 11458	\$0	\$0	\$0	\$0	\$0	\$0

Spending Rationale	Program	Project Name	Project #	FY13	FY14	FY15	FY16	FY17	TOTAL
		11460 Conkling Station relief	PPM 11460	\$203,846	\$0	\$0	\$0	\$0	\$203,846
		11496 Burgoyne 51 - Rebuild Durkeetown Rd.	CD0222	\$745,000	\$0	\$0	\$0	\$0	\$745,000
		1695 Feed 2762 - #6A reconductoring	CD0353	\$600,000	\$0	\$0	\$0	\$0	\$600,000
		11805 Stow F5261 & Chautauqua F5762 transfer underbuilt of	CD0452	\$134,000	\$0	\$0	\$0	\$0	\$134,000
		12835 Station 66 (Union Rd) Rebuild - Sub	PPM 12835	\$281,000	\$282,000	\$0	\$0	\$0	\$563,000
		13180 MV Dyke Rd - Schuyler 66356	PPM 13180	\$5,096	\$117,385	\$0	\$0	\$0	\$122,481
		13273 Steamburg Rebuild	PPM 13273	\$20,000	\$189,615	\$2,153,846	\$0	\$0	\$2,363,461
		15684 Orangeville Substation - Upgrade Bypass Switch	PPM 15684	\$68,288	\$0	\$0	\$0	\$0	\$68,288
		17054 Grand St. 51 - Route 7 Gap Closing	CD0374	\$225,000	\$0	\$0	\$0	\$0	\$225,000
		17808 Lenox Station 513 - Station Improvement	PPM 17808		\$989,000	\$230,000	\$776,000		\$1,006,000
		17815 Hancock Station 137	PPM 17815			\$989,000			\$1,978,000
		17820 Rock City Falls Station - Improvement	PPM 17820				\$510,000	\$510,000	\$1,020,000
AC Other Total				\$5,420,530	\$3,615,100	\$3,857,846	\$1,421,100	\$510,000	\$14,824,976
Blanket		05498 Cent NY-Dist-Asset Replace Blanket	CNC017	\$2,420,000	\$2,495,000	\$2,580,000	\$2,656,000	\$2,735,000	\$12,886,000
		06809 East NY-Dist-Asset Replace Blanket	CNE017	\$2,176,000	\$2,244,000	\$2,320,000	\$2,389,000	\$2,460,000	\$11,589,000
		06893 West NY-Dist-Asset Replace Blanket	CNW017	\$2,602,000	\$2,683,000	\$2,774,000	\$2,856,000	\$2,941,000	\$13,856,000
Blanket Total				\$7,198,000	\$7,422,000	\$7,674,000	\$7,901,000	\$8,136,000	\$38,331,000
Cable Replacement		05365 Brook Road 36954 Getaway cable repl	C29113	\$400,000	\$0	\$0	\$0	\$0	\$400,000
		05982 Henry St. 36 - River Crossing	C29432	\$415,000	\$0	\$0	\$0	\$0	\$415,000
		06044 IE-NC Cable Replacements Placeholde	C13822	\$680,000	\$20,000	\$0	\$0	\$0	\$700,000
		06046 IE-NE Cable Replacements Placeholde	C11099	\$0	\$184,000	\$2,245,500	\$2,750,000	\$2,750,000	\$7,929,500
		06338 NR-Mill St-Failed Ducline	C32650	\$400,000	\$0	\$0	\$0	\$0	\$400,000
		06686 Stonehenge URD	C28826	\$100,000	\$0	\$0	\$0	\$0	\$100,000
		06917 Whitaker 51 River Crossing	C06850	\$95,000	\$0	\$0	\$0	\$0	\$95,000
		09220 Liberty St. UG Cable Replacement	C36469	\$1,316,000	\$1,316,000	\$0	\$0	\$0	\$2,632,000
		09224 Riverside 28855 UG Cable Replacement	C36468	\$1,500,000	\$0	\$0	\$0	\$0	\$1,500,000
		09226 Utica UG Cable Replacement	C36446	\$20,000	\$980,000	\$1,200,000	\$1,700,000	\$1,700,000	\$5,600,000
		09276 Trinity TB4 UG Cables	C36390	\$250,000	\$0	\$0	\$0	\$0	\$250,000
		11500 Buffalo Station 22 - Recond 4 KV Getaways	CD0472	\$207,843	\$0	\$0	\$0	\$0	\$207,843
Cable Replacement Total				\$5,383,843	\$2,500,000	\$3,445,500	\$4,450,000	\$4,450,000	\$20,229,343
Conductor Replacement		06015 IE - NC Replace open wire primary	C31861	\$0	\$0	\$500,000	\$500,000	\$0	\$1,000,000
		06027 IE - NE Replace open wire primary	C31860	\$0	\$0	\$500,000	\$500,000	\$0	\$1,000,000
		06037 IE - NW Replace open wire primary	C31862	\$0	\$0	\$500,000	\$500,000	\$0	\$1,000,000
		17785 CR- Small & steel wire replacement on 27853	CD0551	\$200,000	\$0	\$0	\$0	\$0	\$200,000
		17851 SW - Replace Steel Conductor on Cuba Lake 3761 - Bl	PPM 17851	\$220,000					\$220,000
		17867 SW - Replace Steel Conductor on Cuba Lake 3761 - Ja	PPM 17867	\$470,000					\$470,000
Conductor Replacement Total				\$890,000	\$0	\$1,500,000	\$1,500,000	\$500,000	\$4,390,000
Cutout Replacement		06010 IE - NC Cutout Replacement	C12967	\$100,000	\$0	\$0	\$0	\$0	\$100,000
Cutout Replacement Total				\$100,000	\$0	\$0	\$0	\$0	\$100,000
ISO Capacitor Banks		06977 NE NYISO 13.2kV Sub Cap Banks	C36827	\$0	\$0	\$0	\$0	\$0	\$0
		07004 NE NYISO Dist Line Cap Banks	C36831	\$0	\$0	\$0	\$0	\$0	\$0
ISO Capacitor Banks Total				\$0	\$0	\$0	\$0	\$0	\$0
Network		05519 Central Div. Syr. Ash LVAC. Trans	C36604	\$200,000	\$0	\$0	\$0	\$0	\$200,000
		05520 Central Div. Syr. Temple LVAC. Trans	C36605	\$200,000	\$0	\$0	\$0	\$0	\$200,000
		05522 Central Div. Watertown LVAC. Trans	C36602	\$200,000	\$0	\$0	\$0	\$0	\$200,000
		06258 Network Protector Replacement - C36651	C36651	\$175,000	\$0	\$0	\$0	\$0	\$175,000
		06260 Network Transformer Replacement - C36636	C36636	\$75,000	\$0	\$0	\$0	\$0	\$75,000
Network Total				\$850,000	\$0	\$0	\$0	\$0	\$850,000
Substation Battery and Related		04606 BatteryRpISirategyCo36DxT	C33846	\$300,000	\$300,000	\$300,000	\$300,000	\$300,000	\$1,500,000
		04607 Batts/Charg- NY Central	C32013	\$250,000	\$250,000	\$250,000	\$125,000	\$125,000	\$1,000,000
		04608 Batts/Charg- NY West	C32014	\$250,000	\$250,000	\$250,000	\$250,000	\$250,000	\$1,250,000
		04609 Batts/Charg-NY East	C32012	\$250,000	\$250,000	\$250,000	\$250,000	\$250,000	\$1,250,000
Substation Battery and Related Total				\$1,050,000	\$1,050,000	\$1,050,000	\$925,000	\$925,000	\$5,000,000
Substation Breaker		04902 NC ARP Breakers & Reclosers	C32253	\$1,000,000	\$1,500,000	\$2,000,000	\$2,250,000	\$2,250,000	\$9,000,000
		04947 NW ARP Breakers & Reclosers	C32261	\$1,000,000	\$1,500,000	\$2,000,000	\$2,250,000	\$2,250,000	\$9,000,000
		11619 NY Circuit Breaker Replacement	C37883	\$0	\$2,000,000	\$1,000,000	\$0	\$0	\$3,000,000
Substation Breaker Total				\$3,000,000	\$6,500,000	\$7,000,000	\$6,750,000	\$6,750,000	\$30,000,000

Spending Rationale	Program	Project Name	Project #	FY13	FY14	FY15	FY16	FY17	TOTAL
Substation Circuit Switcher	04703 Circuit Switcher Strategy Co-36 Dxt		C18850	\$0	\$2,000,000	\$1,000,000	\$0	\$5,000,000	\$8,000,000
Substation Circuit Switcher Total				\$0	\$2,000,000	\$1,000,000	\$0	\$5,000,000	\$8,000,000
Substation Indoor	04635 Buffalo Indoor Sub. #29 Refurb.		C06722	\$1,998,000	\$0	\$0	\$0	\$0	\$1,998,000
	04636 Buffalo Indoor Sub. #43 Refurb.		C25660	\$300,000	\$0	\$0	\$0	\$0	\$300,000
	04637 Buffalo Indoor Sub. #62 Refurb.		C25659	\$1,608,630	\$0	\$0	\$0	\$0	\$1,608,630
	04654 Buffalo Station 27 Rebuild - Sta		C33473	\$1,500,000	\$2,750,000	\$750,000	\$0	\$0	\$5,000,000
	04657 Buffalo Station 31 Rebuild - Sub		PPM 04657	\$0	\$0	\$0	\$300,000	\$1,500,000	\$1,800,000
	04663 Buffalo Station 37 Rebuild - Sub		C33474	\$375,000	\$0	\$3,850,000	\$750,000	\$0	\$4,975,000
	04665 Buffalo Station 41 Rebuild - Sub		PPM 04665	\$0	\$0	\$0	\$300,000	\$0	\$300,000
	04670 Buffalo Station 59 Rebuild - Sub		C33475	\$480,000	\$0	\$640,000	\$1,760,000	\$1,200,000	\$4,080,000
	05411 Buffalo Station 27 Rebuild - Line		C33476	\$1,000,000	\$100,000	\$75,000	\$0	\$0	\$1,175,000
	05413 Buffalo Station 29 Rebuild - Fdrs		C06723	\$450,000	\$150,000	\$0	\$0	\$0	\$600,000
	05419 Buffalo Station 31 Rebuild - Line		PPM 05419	\$0	\$0	\$0	\$50,000	\$1,500,000	\$1,550,000
	05430 Buffalo Station 37 Rebuild - Line		C33477	\$1,000,000	\$700,000	\$500,000	\$100,000	\$0	\$2,300,000
	05434 Buffalo Station 41 Rebuild - Line		PPM 05434	\$0	\$0	\$0	\$50,000	\$1,500,000	\$1,550,000
	05438 Buffalo Station 43 Rebuild - Fdrs		C27948	\$75,000	\$0	\$0	\$0	\$0	\$75,000
	05447 Buffalo Station 52 Rebuild - Fdrs		C27949	\$200,000	\$25,000	\$0	\$0	\$0	\$225,000
	05451 Buffalo Station 59 Rebuild - Line		C33478	\$340,000	\$1,364,154	\$2,156,471	\$230,000	\$0	\$4,090,625
	11877 Rock Cut #286 2nd Trant and Metalclad		PPM 11877	\$9,326,630	\$5,089,154	\$7,971,471	\$3,600,000	\$5,820,000	\$31,807,255
Substation Indoor Total				\$9,326,630	\$5,089,154	\$7,971,471	\$3,600,000	\$5,820,000	\$31,807,255
Substation Metal-Clad Sv	04582 Altamont Sub Metalclad Replacement		C32296	\$750,000	\$960,000	\$940,000	\$100,000	\$0	\$2,200,000
	04867 Market Hill Sub Metalclad Replacement		C32298	\$200,000	\$960,000	\$940,000	\$100,000	\$0	\$2,200,000
	05269 Altamont Switchgear Replacm D_Line		C33746	\$150,000	\$0	\$0	\$0	\$0	\$150,000
	05846 Emmet St - Repl TB1 and mclad		C17952	\$0	\$345,865	\$1,303,077	\$602,885	\$123,750	\$2,375,577
	09244 Chrisler Metal Clad Replacement		C36213	\$0	\$314,423	\$1,250,000	\$548,077	\$0	\$2,112,500
	13341 Union St 376 - Replace Metalclad Gear		PPM 13341	\$0	\$0	\$20,000	\$341,731	\$1,361,250	\$1,722,981
	13342 Johnson Rd - Replace Metalclad Gear		PPM 13342	\$0	\$0	\$20,000	\$341,731	\$1,361,250	\$1,722,981
	13343 Pinebush - Replace Metalclad Gear		PPM 13343	\$0	\$0	\$20,000	\$20,000	\$341,731	\$381,731
	13345 Hopkins 253 - Replace Metalclad Gear		PPM 13345	\$0	\$20,000	\$335,000	\$1,326,000	\$619,000	\$2,300,000
	13346 Whitesboro 632 - Replace Metalclad Gear		PPM 13346	\$0	\$0	\$0	\$20,000	\$341,731	\$361,731
	17828 Henny Street Station 316 - Replace Metalclad		PPM 17828	\$20,000	\$335,000	\$1,326,000	\$619,000	\$0	\$2,300,000
Substation Metal-Clad Switchgear Total				\$1,120,000	\$1,975,288	\$5,214,077	\$3,919,424	\$4,148,712	\$16,377,501
Substation Mobile	11331 New NY Mobile Substation 69kV - 13.8x4.8x4.16kV		PPM 11331	\$1,000,000	\$1,000,000	\$0	\$0	\$0	\$2,000,000
	17809 Mobile Sustain 7C - Refurbish and Upgrade		PPM 17809	\$700,000	\$0	\$544,000	\$394,000	\$0	\$938,000
	17811 Mobile Substation 2E - Replacement		PPM 17811	\$0	\$0	\$526,000	\$659,000	\$0	\$1,185,000
	17812 Mobile Substation 4E - Refurbish and Upgrade		PPM 17812	\$0	\$0	\$0	\$0	\$0	\$0
	17821 Mobile Substation 6E - Rewind		PPM 17821	\$0	\$0	\$0	\$0	\$0	\$0
Substation Mobile Total				\$1,700,000	\$1,000,000	\$1,070,000	\$1,053,000	\$0	\$4,823,000
Substation Power Transf	04962 NY ARP Spare Substation Transformer		C26055	\$1,679,000	\$900,000	\$0	\$0	\$0	\$2,579,000
	09248 Cuyler#24 Inst 34/4kV Substation		C36102	\$300,000	\$200,000	\$0	\$0	\$0	\$500,000
	09251 Fisher Ave Replace 34/13kV Trans		C36101	\$917,000	\$0	\$0	\$0	\$0	\$917,000
	09275 TRANS REPL NY		C36043	\$0	\$0	\$0	\$0	\$0	\$0
	17796 Liberty Street Station 94-Replace Transformer		PPM 17796	\$917,000	\$0	\$0	\$0	\$0	\$917,000
	17798 Summit Station Transformer Replacement		PPM 17798	\$0	\$765,000	\$0	\$0	\$0	\$765,000
	17805 Station 124 - Alameda Ave Transformer Replacement		PPM 17805	\$0	\$0	\$0	\$0	\$2,806,000	\$2,806,000
	17806 Rock City Station 623 - Transformer Replacement		PPM17806	\$0	\$0	\$1,012,000	\$0	\$0	\$1,012,000
	17807 Indian Lake - Replace Transformers		PPM 17807	\$0	\$0	\$1,012,000	\$0	\$0	\$1,012,000
Substation Power Transformer Total				\$3,813,000	\$1,865,000	\$1,012,000	\$1,012,000	\$2,806,000	\$10,508,000
Substation RTU	04969 NY RTU Program - Dxt Subs		C22151	\$2,200,000	\$500,000	\$0	\$0	\$0	\$2,700,000
Substation RTU Total				\$2,200,000	\$500,000	\$0	\$0	\$0	\$2,700,000
TBD	05061 Reserve for Asset Replacement Unidentified Specifics	RESERVE 036_017 SUB		\$8,500,000	\$6,500,000	\$9,896,480	\$2,448,742	-\$416,952	-\$22,864,690
	06508 Reserve for Asset Replacement Unidentified Specifics	RESERVE 036_017 LINF		-\$6,890,003	\$5,012,458	\$10,918,586	\$10,350,734	\$8,700,240	\$28,092,015
TBD Total				-\$15,390,003	-\$1,487,542	\$1,022,106	\$12,799,476	\$8,283,288	\$5,227,325
Buffalo Street Light	18022 Buffalo Street Light Cable Replacement		PPM 18022	\$2,500,000	\$2,500,000	\$2,500,000	\$2,500,000	\$2,500,000	\$12,500,000
Buffalo Street Light Total				\$2,500,000	\$2,500,000	\$2,500,000	\$2,500,000	\$2,500,000	\$12,500,000
Asset Condition Total				\$29,162,000	\$34,529,000	\$44,317,000	\$47,831,000	\$49,829,000	\$205,668,000
Non-Infrastructure	04508 Cent NY-General-Genl Equip Blanket		CNC070	\$1,085,000	\$746,000	\$778,000	\$806,000	\$1,272,000	\$4,687,000
	04525 East NY-Genl Equip Budgetary Reserv		CNE070	\$865,000	\$594,000	\$621,000	\$643,000	\$1,015,000	\$3,738,000

Spending Rationale	Program	Project Name	Project #	FY13	FY14	FY15	FY16	FY17	TOTAL
		04559 Telecom and Radio Equipment	C04157	\$1,075,000	\$1,110,000	\$1,150,000	\$1,150,000	\$1,150,000	\$5,635,000
		04563 West NY-General-Genl Equip Blanket	CNW070	\$1,135,000	\$780,000	\$814,000	\$844,000	\$1,331,000	\$4,904,000
		05509 Cent NY-Dist-Telecomm Blanket	CNC021	\$14,000	\$15,000	\$16,000	\$17,000	\$18,000	\$80,000
		05821 East NY-Dist-Telecomm Blanket	CNE021	\$11,000	\$12,000	\$13,000	\$14,000	\$15,000	\$65,000
		06905 West NY-Dist-Telecomm Blanket	CNW021	\$9,000	\$9,000	\$10,000	\$10,000	\$10,000	\$48,000
Blanket Total				\$4,194,000	\$3,266,000	\$3,402,000	\$3,484,000	\$4,811,000	\$19,157,000
Non-Infrastructure		17519 Belfry Mountain-site revamp	PPM 17519	\$0	\$0	\$200,000	\$0	\$0	\$200,000
		17521 Altica Roadway Re-build	PPM 17521	\$200,000	\$0	\$0	\$0	\$0	\$200,000
		17522 Jordanville Site Purchase/Rebuild	PPM 17522	\$0	\$0	\$0	\$200,000	\$0	\$200,000
		17523 Duaneburg Site Purchase/Rebuild	PPM 17523	\$0	\$0	\$0	\$200,000	\$0	\$200,000
		17524 Expand VHF Coverage - Northeast	PPM 17524	\$0	\$0	\$400,000	\$0	\$0	\$400,000
		17525 Bald Mountain Tower Replacement	PPM 17525	\$0	\$0	\$400,000	\$0	\$0	\$400,000
		17526 Recloser Communication RF Links	PPM 17526	\$100,000	\$100,000	\$0	\$0	\$0	\$200,000
Non-Infrastructure Total				\$300,000	\$100,000	\$1,000,000	\$400,000	\$0	\$1,800,000
TBD		04546 Reserve for General Equipment Specifics & Schedule	RESERVE 036_070 LINE	\$250,000	\$250,000	\$250,000	\$250,000	\$250,000	\$1,250,000
TBD Total				\$250,000	\$250,000	\$250,000	\$250,000	\$250,000	\$1,250,000
Non-Infrastructure Total				\$4,744,000	\$3,616,000	\$4,652,000	\$4,134,000	\$5,061,000	\$22,207,000
Grand Total				\$2,350,000,000	\$2,397,850,000	\$2,526,640,000	\$2,636,930,000	\$2,777,000,000	\$1,268,120,000



**Rebuttal Testimony of the Electric Infrastructure and Operations Panel**

Exhibit \_\_ (EIOP-3R)

Mid-span mowing table of planned sites

## Lines Scheduled for Mid-Span Mowing in FY14

FY14 Mid-span Mowing			
ROW #	Line Number	Line Name	Division
11016	14	Clay - GE	NYCE
11018	11	Clay - Teall #11	NYCE
11038	3	Oneida - Cortland	NYCE
11040	4	Oswego - Clay	NYCE
11048	2	SUNY - Cortland	NYCE
11310	1 & 2	Boonville - Porter	NYMV
11328	6	Porter - Terminal	NYMV
11336	7	Terminal - Schuyler	NYMV
11506	12	Alcoa - Dennison	NYNO
11518	22	Browns Falls - Newton Falls	NYNO
11530	9	Colton - Carry Falls	NYNO
11550	1	Raymondville - Norfolk	NYNO
11600	4	Thousand Is - Coffeen	NYNO
12756	12	Geres Lock - Onon. CoGen	NYCE
12026	15	Grooms - Inman Rd	NYCA
12028	13	Grooms - Johnson	NYCA
12036	2	Menands - Reynolds Rd	NYCA
12050	17	Rotterdam - Albany	NYCA
12052	14 & 15	Rotterdam - GE	NYCA
12056	35	Rotterdam - Woodlawn	NYCA
12064	5 & 9	Trinity - Albany	NYCA
12506	12	Clinton - Marshville	NYNE
12510	6	Inghams - St Johnsville	NYNE
10040	129	Packard - Huntley #129	NYFR
10042	182	Packard - Union Carbide (Grand Isl)	NYFR
10202	117 & 119	"Batavia - Golah #117 119"	NYGN
10402	158	Valley - Ischua #158	NYSW

Mid-span Mowing will be performed on sections of the above lines according to the Company's Part 84 Transmission ROW Management Plan



**Rebuttal Testimony of the Electric Infrastructure and Operations Panel**

Exhibit \_\_ (EIOP-4R)

Copy of Response to IR DPS-449 (CVB-1)

Date of Request: July 19, 2012  
Due Date: July 30, 2012

Request No. DPS -449 (CVB -1)  
NMPC Req. No. NM 630

NIAGARA MOHAWK POWER CORPORATION  
Case No. 12-E-0201 and 12-G-0202 - Niagara Mohawk Power Corporation  
d/b/a National Grid - Electric and Gas Rates

Request for Information

FROM: Christian Bonvin  
TO: Electric Infrastructure and Operations Panel  
SUBJECT: Tree Trimming

Request:

1. Please provide the budgeted and actual expenditures, on an annual basis, related to the vegetation management for 2010 through 2012 and the annual forecasted spending levels for 2013 through 2015. The information may be provided on a calendar year or fiscal year basis.
  - a) Distribution Cycle Trimming
  - b) Hazard Tree On-Cycle
  - c) Hazard Tree Off-Cycle
  - d) Worst Feeders
  - e) Interim/Spot Trim
  - f) Sub-T On-road
  - g) Sub-T Off-road
  - h) Police/Flagman Detail
  - i) Customer Requests
  - j) Trouble Maintenance
  - k) Other

Response:

1. The annual budgeted and actual expenditures related to the vegetation management for FY10, FY11 and FY12 along with the forecasted annual spending levels for these items FY13 through FY15 is provided in Attachment 1 to CVB-1.

Name of Respondent:  
Craig M. Allen

Date of Reply:  
July 27, 2012

**CVB-1 Response**

	Fiscal Year						
	2010	2011	2012	2013 Forecast	2014 Forecast	2015 Forecast	
a) Activity Roll up							
b) Distribution Cycle Trim	\$ 26,429,359	\$ 26,634,563	\$ 26,995,792	\$ 27,495,085	\$ 27,770,036	\$ 28,047,736	
c) Hazard Tree - On Cycle	\$ 3,957,321	\$ 5,060,275	\$ 6,323,465	\$ 6,322,210	\$ 6,385,432	\$ 6,449,286	
d) Hazard Tree - Off Cycle	\$ 12,346	\$ 3,561					
e) Worst Feeders	\$ 131,916	\$ 75,789	\$ 105,550	\$ 105,549	\$ 106,604	\$ 107,671	
f) Interim/Spot Trim	\$ 2,409	\$ 658	\$ 487	\$ 487	\$ 492	\$ 497	
g) Sub-T On-road	\$ 33,435	\$ 12,984	\$ 9,496	\$ 9,495	\$ 9,590	\$ 9,686	
h) Police/Flagman Detail	\$ 492	\$ 430					
i) CustomerRequests	\$ 2,092,406	\$ 2,238,870	\$ 2,735,181	\$ 2,356,969	\$ 2,380,539	\$ 2,404,344	
J) Trouble Maintenance	\$ 1,373,522	\$ 1,358,040	\$ 1,276,967	\$ 1,116,554	\$ 1,127,720	\$ 1,138,997	
k) Core Crew - contractors	\$ 287,344	\$ 242,877	\$ 266,458	\$ 265,317	\$ 267,970	\$ 270,650	
Core Crew - all other activities	\$ 2,166,163	\$ 2,136,046	\$ 1,975,704	\$ 2,119,768	\$ 2,140,966	\$ 2,162,376	
Total Actual Spend*	\$ 36,486,712	\$ 37,788,261	\$ 39,689,098				
Total Distribution Veg Budget**	\$ 38,958,000	\$ 39,825,901	\$ 40,557,568	\$ 39,791,434	\$ 40,189,349	\$ 40,591,242	
					1% inflation	1% inflation	

\* Non Major storm spend is reclassified out of the Vegetation Operations budget at year end.

\*\* The Vegetation Operations budget is not allocated down to the activity level.



**Case 12-E-0201**

**Rebuttal Testimony of the Electric Infrastructure and Operations Panel**

Exhibit \_\_ (EIOP-5R)

I&M Repair Performance CY2009-Aug. 31, 2012

Summary of Deficiencies and Repair Activity - 2009 through Aug. 31. 2012									
Calendar Year	Priority Level / Repair Expected	Deficiencies Found (Total)	Repaired In Time Frame	Repaired - Overdue	Not Repaired - Not Due	Not Repaired - Overdue	Made	Missed	Not Due yet
<b>2009</b>									
	II Within 1 year	20358	19814	544	0	0	97.33%	2.67%	0.00%
	III Within 3 years	59068	48981	309	4534	5244	82.92%	9.40%	7.68%
<b>2010</b>									
	II Within 1 year	21435	19961	1471	0	3	93.12%	6.88%	0.00%
	III Within 3 years	41057	11083	0	29974	0	26.99%	0.00%	73.01%
<b>2011</b>									
	II Within 1 year	28082	22095	1149	4650	188	78.68%	4.76%	16.56%
	III Within 3 years	22101	4451	0	17650	0	20.14%	0.00%	79.86%
<b>2012</b>									
	II Within 1 year	27936	1653	0	26283	0	5.92%	0.00%	94.08%
	III Within 3 years	23375	517	0	22858	0	2.21%	0.00%	97.79%

Rebuttal Testimony of  
Service Company Panel

**Before the Public Service Commission**

**NIAGARA MOHAWK POWER CORPORATION d/b/a NATIONAL GRID**

**Rebuttal Testimony**

**of the**

**Service Company Panel**

**Case 12-E-0201**  
**Case 12-G-0202**

**Rebuttal Testimony of the Service Company Panel**

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**Rebuttal Testimony of the Service Company Panel**

1 **I. Introduction**

2 **Q. Please identify the members of the Service Company Panel.**

3 A. The Panel consists of David B. Doxsee, James M. Molloy, and Sharon  
4 Partridge.

5

6 **Q. Is this the Service Company Panel that testified previously in these**  
7 **proceedings?**

8 A. Yes, this Panel provided direct testimony as part of Niagara Mohawk's  
9 April 27, 2012 filing.

10

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

12 A. The Panel responds to certain issues raised by the Department of Public  
13 Service Staff Accounting Panel ("Staff") in its Direct Testimony dated  
14 August 31, 2012. Specifically, we are addressing Staff's concerns with: 1)  
15 the Company's service level agreements; (2) the review and approval of  
16 the monthly service company bill; and (3) the monthly budgeting and  
17 review process.

18

19 **II. Service Level Agreements**

20 **Q. Staff expresses concerns (at 151, 158) that Niagara Mohawk does not**  
21 **treat the service company as it would "any other non-affiliated third-**

**Rebuttal Testimony of the Service Company Panel**

1           **party vendor” and that Company’s current SLAs “contain no**  
2           **provision for bench marking or market testing of the services that are**  
3           **provided . . .” and do not contain “pricing information such as price**  
4           **and quantities of services to be provided.” Does the Panel have**  
5           **comments regarding these concerns?**

6    A.    National Grid’s service company differs from non-affiliated, third-party  
7           vendors in important respects that should not be lost sight of in arriving  
8           at the appropriate governance structure. Unlike non-affiliated, third-  
9           party vendors, the service company charges out its services at cost and is  
10          not a profit-seeking venture that is compensated for risks that non-  
11          affiliated, third party vendors can be expected to absorb. In some cases,  
12          it would not be practicable for National Grid to meet each of Staff’s  
13          proposals for each and every service company function. That being said,  
14          while progress has been made on the SLAs, National Grid recognizes  
15          that further improvements can be achieved. National Grid understands  
16          Staff’s concerns and agrees that it must demonstrate to the Commission’s  
17          satisfaction that the service company’s charges to Niagara Mohawk are  
18          just and reasonable. National Grid commits to working with Staff to  
19          develop SLAs that will contain costs and more detailed service  
20          descriptions and, to the extent practicable, establish meaningful  
21          performance metrics to ensure that the services provided by the service

**Rebuttal Testimony of the Service Company Panel**

1 companies achieve reasonable levels of cost and quality and provide a  
2 basis for comparing the cost of services, along with other important  
3 criteria, provided by the service companies to appropriate market  
4 alternatives. To the extent one or more of such comparisons indicates  
5 that the National Grid service company function does not provide  
6 reasonable value to Niagara Mohawk, National Grid will develop a plan  
7 to address the discrepancy. We believe that the recent audits conducted  
8 by NorthStar Consulting Group, Liberty Consulting and Overland  
9 Consulting will provide information and suggestions that are likely to be  
10 useful in establishing SLAs that address Staff's concerns while affording  
11 National Grid the flexibility needed to manage its operations in a  
12 constantly evolving business environment and to continue to leverage the  
13 synergies of a large organization.

14

15 **Q. Does the Company agree with Staff's recommendation (at 164-165)**  
16 **that after the consolidated accounting system has been in place long**  
17 **enough that twelve months of cost data are available, the Company**  
18 **should undertake an analysis that will show that Niagara Mohawk is**  
19 **not cross subsidizing its affiliates?**

20 A. Once the U.S. Foundation Project is in place for a sufficient period, the  
21 Company would be willing to provide an analysis demonstrating that its

**Rebuttal Testimony of the Service Company Panel**

1 cost allocation policies and procedures have been successfully  
2 implemented and that, as a consequence, National Grid’s affiliates are  
3 being assigned costs that are accurate, transparent and consistent with  
4 those policies and procedures. As discussed in the Panel’s direct  
5 testimony (at 48), National Grid’s revised cost allocation policies and  
6 procedures are intended to achieve a cost causative allocation process  
7 that will be consistently applied throughout National Grid and will rely  
8 on a general allocator only when there is no readily determinable cost  
9 causative basis available to allocate costs. By successfully implementing  
10 these policies and procedures, National Grid believes that it will ensure  
11 that no cross subsidization is occurring in the National Grid organization.

12  
13 **III. Review and Approval of the Monthly Service Company Bill /**  
14 **Monthly Budgeting and Review Process**

15 **Q. Does the Panel have any comments with respect to Staff’s assertion**  
16 **(at 157) that the problem with the current review of monthly service**  
17 **company bills is that “there is no one from the Niagara Mohawk**  
18 **operating company who is objectively or independently reviewing**  
19 **and making sure the charges it is incurring from the service**  
20 **companies are correct”?**

21 **A.** There is no reason to believe that a service company employee is less

**Rebuttal Testimony of the Service Company Panel**

1 capable of or less interested in representing the interests of Niagara  
2 Mohawk than a Niagara Mohawk employee. In recognition of Staff's  
3 ongoing concerns, however, National Grid will assign a Niagara  
4 Mohawk employee to review the Company's bills and charges from the  
5 service company.

6

7 **Q. Does the Panel agree with Staff's claim (at 157-158) that the review**  
8 **process for service company bills is problematic because the bills are**  
9 **"automatically paid in lieu of any review"?**

10 A. No. Staff incorrectly equates the timing of the review of a bill with the  
11 absence of any review. The service company bill review process is  
12 ongoing and multiple levels of review occur. Whether this review occurs  
13 before or after the service company bill is paid makes very little  
14 difference as long as the review takes place within a reasonable period of  
15 time. If, after review, a correction is necessary to a bill that has already  
16 been paid, a manual journal entry is prepared and run through the billing  
17 in the month it is entered. From National Grid's perspective, this is an  
18 administratively preferable way to perform service company billing  
19 compared to holding up bills while the various layers of review take  
20 place. National Grid believes that it should be afforded the flexibility to  
21 manage its service company billings in accordance with its current

**Rebuttal Testimony of the Service Company Panel**

1 practice as long as it maintains procedures that will assure that service  
2 company bills are accurate.

3

4 **Q. Does the Panel agree with Staff's assertion (at 163) that the monthly**  
5 **reporting of actuals versus budget does nothing to ensure that**  
6 **service company charges are appropriately allocated?**

7 A. No. When variances from budgets are identified, they receive a closer  
8 review. In the preparation of the monthly financial report to the  
9 President of the New York Jurisdiction, each functional area of the  
10 service company provides detailed analysis and variance explanations  
11 that are reviewed by the New York Finance team to ensure that the  
12 charges are in line with expectations and that the variance explanations  
13 adequately address deviations from budgeted and prior year expense  
14 levels. To the extent that variances result from an erroneous allocation of  
15 affiliate costs, they would be identified and corrected as a result of the  
16 monthly review of actuals versus budget.

17

18 Furthermore, the New York Finance monthly budgeting process is more  
19 than a reporting of actuals versus budget. The New York Finance team is  
20 also able to compare prior year actuals for Niagara Mohawk and the  
21 allocations to all other National Grid companies to review allocation

**Rebuttal Testimony of the Service Company Panel**

1 shifts and identify and address any improper allocations or cross-  
2 subsidization concerns. It should be noted that the New York Finance  
3 team is comprised of highly experienced personnel dedicated to the New  
4 York operating companies.

5

6 **Q. Has National Grid recently implemented any additional in-depth**  
7 **analyses that will enhance the internal review of service company**  
8 **charges?**

9 A. Yes. A more in-depth analysis began in fiscal year 2013. Specifically, a  
10 report was developed to sample service company accounts payable costs  
11 (direct or allocated) charged to Niagara Mohawk. The sampling includes  
12 all line items that allocate more than \$10,000 to Niagara Mohawk, as  
13 well as any line items under \$10,000 that appear unusual based on the  
14 vendor name and/or allocation percentage. The sample comprises more  
15 than 75 percent of the accounts payable costs charged to Niagara  
16 Mohawk. Line items are sorted by functional area and by vendor name  
17 to facilitate the review. Decision support teams representing each service  
18 company function perform a line by line review of the items for their  
19 respective functions to determine whether the charges are correctly  
20 allocated to Niagara Mohawk, and submit their findings to New York  
21 Finance with a brief description of the nature of the charge, whether each

**Rebuttal Testimony of the Service Company Panel**

1 line item is correct, and when a correction will be processed if the charge  
2 is incorrect.

3  
4 This additional analysis provides improved attention to line item detail in  
5 the review of service company charges. National Grid hopes to build on  
6 this new process to develop service company budgeting and billing  
7 processes that will address the concerns identified by Staff and improve  
8 the accuracy of service company billings.

9

10 **IV. Conclusion**

11 **Q. Does this conclude the Panel's rebuttal testimony?**

12 **A. Yes.**

Rebuttal Testimony of  
Michael E. Barrett

**Before the Public Service Commission**

**NIAGARA MOHAWK POWER CORPORATION d/b/a NATIONAL GRID**

**Rebuttal Testimony**

**of**

**Michael E. Barrett**

**Case 12-E-0201**

**Case 12-G-0202**

**Rebuttal Testimony of Michael E. Barrett**

1 **Q. Please state your name and business address.**

2 A. My name is Michael Barrett. I am a Partner with the accounting firm of  
3 Ernst & Young LLP (“E&Y”). My business address is 55 Ivan Allen  
4 Boulevard, Atlanta, GA 30308.

5  
6 **Q. Please describe your professional and educational qualifications.**

7 A. My curriculum vita, which fully details my academic and work  
8 experience, is attached as part of Exhibit \_\_ (SCP-5), which is sponsored  
9 by the Service Company Panel.

10

11 **Q. What is purpose of your rebuttal testimony?**

12 A. E&Y was previously retained by National Grid Service Company, Inc.  
13 (“National Grid”) to analyze service company operating & maintenance  
14 (“O&M”) costs being allocated to the various National Grid entities and  
15 related business units. E&Y performed an analysis of these costs, which  
16 was included in Niagara Mohawk’s April 2012 filing in these proceedings  
17 as Exhibit \_\_ (SCP-5). The purpose of my testimony is to rebut the  
18 testimony of the Staff Accounting Panel and Staff Witness Richard  
19 Schuler Jr. concerning that E&Y analysis.

20

21 **Q. Please summarize your response to Staff’s claims concerning the**

**Rebuttal Testimony of Michael E. Barrett**

1           **E&Y analysis.**

2       A.     The arguments advanced by Staff in support of its recommendation that  
3           the Commission reject the Company's proposed normalization  
4           adjustments that were supported by E&Y's analysis are without  
5           foundation. In claiming that E&Y did not demonstrate that its analysis  
6           was statistically valid, Staff fails to recognize that the normalization  
7           adjustments derived from E&Y's analysis are not the product of an  
8           extrapolation of random sample data; they are directly observed  
9           adjustments. Staff does not dispute the directly observed adjustments. In  
10          addition, Staff's claim that E&Y's analysis of service company O&M  
11          costs should be rejected because E&Y failed to analyze capital costs is a  
12          *non-sequitur*. It was appropriate for E&Y to confine its analysis and  
13          proposed adjustments to O&M costs.

14  
15          Staff's criticisms of E&Y's approach are unwarranted. E&Y's risk-  
16          based approach was better and more effective than a random sampling  
17          approach. E&Y applied random selection statistical sampling at the  
18          vendor level when it determined the specific vendor population was  
19          sufficiently homogenous and it was appropriate to do so. E&Y also  
20          performed additional sampling or complete validation beyond the  
21          statistical sample when errors were identified. There is no basis for Staff

**Rebuttal Testimony of Michael E. Barrett**

1 to assume that the application of a randomly selected statistical sample  
2 approach would have resulted in a more representative conclusion.

3

4 To summarize, the normalization adjustments proposed by the Company  
5 and supported by E&Y's analysis are completely reasonable.

6

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

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

10 (i) Exhibit \_\_ (MB-1R) presents an analysis of the impact of  
11 transactions discussed by the Staff Accounting Panel (at 80 to 82)  
12 on Niagara Mohawk's test year expenses; and

13 (ii) Exhibit \_\_ (MB-2R) presents an analysis of the transactions  
14 discussed by the Staff Accounting Panel (at 80 to 82) and  
15 demonstrates why the Staff Accounting Panel's criticisms of  
16 E&Y's testing of these transactions are not valid.

17

18 **Q. What specific claims in Staff's testimony do you disagree with?**

19 A. E&Y assisted Niagara Mohawk in reviewing its Historic Test Year O&M  
20 charges from the service companies. E&Y's analysis supports  
21 normalization adjustments that increased Rate Year O&M expenses for

**Rebuttal Testimony of Michael E. Barrett**

1 the Company's electric operations \$2.420 million and decreased Rate Year  
2 O&M expenses for its gas operations \$0.673 million. The Staff  
3 Accounting Panel does not accept these adjustments based on claims that:

- 4 ○ Although E&Y states that they sampled \$1.023 billion of  
5 transactions, in fact they only tested a fraction of that amount  
6 (Staff Accounting Panel at 80),
- 7 ○ The examination that E&Y performed on a small number of  
8 samples was not sufficient (Staff Accounting Panel at 82),
- 9 ○ E&Y's analysis only looked at O&M expenses; they made no  
10 examination of capital related charges. By excluding 40  
11 percent of the total charges from the testing population, the  
12 validity and completeness of the analysis is further  
13 compromised (Staff Accounting Panel at 87), and
- 14 ○ E&Y has not shown that its study is reasonably representative,  
15 unbiased or statistically valid (Staff Accounting Panel at 80).

16

17 I disagree with these claims as well as Staff's overall recommendation that  
18 the Company's proposed normalization adjustment as supported by  
19 E&Y's analysis should be rejected.

20

21 **Q. The Staff Accounting Panel, citing Staff Witness Schuler's testimony,**

**Rebuttal Testimony of Michael E. Barrett**

1           **states (at 80), “E&Y has not shown that the study is reasonably**  
2           **representative, unbiased or statistically valid.” Do you agree that this**  
3           **is a valid reason to reject the normalization adjustments that are the**  
4           **product of that analysis?**

5    A.    No, I do not. The normalization adjustments that result from E&Y’s  
6           analysis are not the product of an extrapolation of random sample data.  
7           The adjustments identified by E&Y are directly observed and are fully  
8           supported on that basis. The Staff Accounting Panel does not take issue  
9           with the specific cost errors corrected by the E&Y analysis.

10

11   **Q.    Did E&Y use a statistical approach to the overall analysis conducted**  
12           **in this case?**

13    A.    No. We did not use a pure random selection statistical sampling approach.  
14           We concluded that based on the nature of the costs, the lack of  
15           homogeneity among the costs, and the resulting difficulty of drawing  
16           random samples that would be representative of the population, a  
17           statistical sampling approach would not be effective. We followed a  
18           sampling approach that in part was based on a risk-based screening to  
19           identify costs to review and utilized random selection statistical methods.

20

21   **Q.    Please explain.**

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1 A. We took a risk-based approach based on the nature of the various types of  
2 costs included in the service company O&M costs (*e.g.*, payables, labor,  
3 and employee expenses) that was designed to achieve adequate coverage  
4 of those total amounts and allow us to express a conclusion on that total.  
5  
6 We worked with National Grid management to gain an understanding, for  
7 each of these categories of costs, of the general approach used by National  
8 Grid to account for costs, to validate the costs charged to the particular  
9 cost centers, and to define the business relationship with vendors retained  
10 and the nature of the services or goods provided. Further, we reviewed  
11 and discussed internal controls over procurement, labor cost allocations,  
12 and accounts payable processing to inform ourselves as to potential risks  
13 of improper cost direction by time period, business unit, or cost type.  
14  
15 We then reviewed data in each of the categories, and validated this data  
16 through our testing. We believe that sufficient data was tested to reach a  
17 conclusion through a combination of selecting the largest items in a  
18 population and judgmental sampling from the remaining items. Using this  
19 risk based sample selection methodology, we reviewed sufficient records  
20 to obtain a target percentage of review coverage that we deemed adequate  
21 for us to draw a conclusion on each of the categories.

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1 For each category of cost, specific items were selected (such as the  
2 specific vendors selected for our accounts payable review). We gained or  
3 confirmed our understanding of the nature of the transactions by  
4 evaluating the relationship with the specific vendor in question (*e.g.*, the  
5 nature of the vendor and services they were hired to perform) as well as  
6 how the associated costs were developed, documented, allocated and  
7 reported. Based on that information, we were able to use our professional  
8 judgment to identify an appropriate sample of the vendors/transactions  
9 where the risk of inconsistency or error in recording or allocating these  
10 costs was higher. We then focused on additional review of the highest risk  
11 areas. We were thus able to achieve adequate review coverage to support  
12 our conclusions through testing rigor correlated with the level of risk.  
13 Where extensive review of documentation was warranted by the level of  
14 risk, based on our review of all supporting documentation, we performed  
15 more rigorous and extensive testing.

16

17 **Q. How does the specific cost information affect the risk based analysis?**

18 A. The specific cost information affects the risk based analysis in a number of  
19 ways.

- 20 • The invoice or other corroborating information informs the risk  
21 analysis. Other corroborating information are provided to National

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1           Grid by the vendor and are utilized by National Grid as the basis for  
2           payment, and include, for example, summary contractor charge data  
3           (for temporary labor vendors), telephone line charges by employee (for  
4           cellular telephone charges), and vendor and lease payment schedules  
5           (for leases).

6           • Some costs are recurring under the terms of a contract, some vendors  
7           perform recurring services that vary within some bounds, and some  
8           costs are simply one time purchases. The significance of the  
9           recurrence of the cost is the impact it has on the risk of error or  
10          inconsistency in cost allocation, and thus on the need for additional  
11          testing. For example, once compliance with the contract terms is  
12          determined, costs under an annual service contract that are direct  
13          charged to a particular function exhibit little risk of error if the  
14          subsequent monthly invoices are similar. Costs charged by a recurring  
15          vendor also exhibit lower risk of outlier invoices. Whereas for one-  
16          time costs, there are fewer comparable costs or corroborating cost  
17          information to help assess risk, and as such, additional testing may be  
18          warranted.

19          • Charging can either be by a direct charge or by applying an allocation  
20          methodology. Purely random sampling methodologies would take no  
21          account of the method by which a cost was charged to a cost center.

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1           However, there is a lower risk of incorrect charging for a cost related  
2           to a good or service that is used in a specific program and in a specific  
3           business unit when that cost is direct charged to that business unit. At  
4           the same time, there can also be a lower risk in a purely allocated cost,  
5           such as the provision of benefit plan management services, which are  
6           established in well-defined bill pool/allocation codes. Moreover, a key  
7           risk reducing element results from the consistent application of  
8           consistent direct charge or bill pool/allocation code methodologies  
9           over a long period of time. Our risk based sampling approach  
10          appropriately considers these factors.

11          • In the payroll cost area, job profiles within a department are expected  
12          to be allocated to business units in certain ways. Where individuals  
13          input their own allocation of costs, outliers from the expected charging  
14          are higher risk and may require further testing. Conversely, where  
15          departments had default cost allocations in place and individuals  
16          would have to manually enter exceptions to deviate from the default  
17          allocators, the higher risk items related to individuals that never  
18          charged the default allocator.

19          • In the employee expense cost area, the type of cost and the description  
20          facilitated the use of key word searches to identify costs that would not  
21          normally be charged to customers. These techniques were applied to

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1           the population of employee expenses to highlight higher risk items for  
2           further testing.

3

4   **Q.   The Staff Accounting Panel (at 80-82) identifies a number of test items**  
5       **for which it contends that E&Y only tested a small portion of the costs**  
6       **for particular vendors. Do you have any comments concerning these**  
7       **illustrations?**

8   A.   The Staff Accounting Panel’s examples are not representative of vendors  
9       charging costs to Niagara Mohawk.

- 10       • As shown on Exhibit \_\_ (MB-1R), only three of the eight vendors in  
11       the Staff Accounting Panel’s examples had any costs charged to  
12       Niagara Mohawk at all, and one of those three charged costs that were  
13       immaterial. Accordingly, these provide no basis for the Staff  
14       Accounting Panel to assess our work or the validity of our conclusions.
- 15       • Based on the nature of the vendor costs in the cited examples, the costs  
16       had a low risk of misapplication.
- 17       • Exhibit \_\_ (MB-1R) provides a table that sets forth the impact of the  
18       specific examples cited by the Staff Accounting Panel on Niagara  
19       Mohawk’s electric and gas operations in the Historic Test Year. As  
20       shown in the exhibit, the total charges associated with the items that  
21       the Staff Accounting Panel takes issue with is approximately \$4.5

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1 million in the Historic Test Year to Niagara Mohawk's electric and gas  
2 operations and, of those charges, E&Y made adjustments of \$(15,664)  
3 and \$(163) for the electric and gas segments, respectively, of the total  
4 \$2.420 million in electric O&M adjustments and \$(0.673) million in  
5 gas O&M adjustments identified in our analysis. The Staff  
6 Accounting Panel inappropriately draws a conclusion concerning our  
7 analysis and proposed Rate Year adjustments based on these eight  
8 items that have virtually no impact on Niagara Mohawk's costs. In  
9 addition, the Staff Accounting Panel does not contend that E&Y's  
10 adjustments of \$(15,664) and \$(163) relative to these eight examples  
11 are not accurate.

12  
13 **Q. Have you prepared an exhibit that describes the basis of the**  
14 **transactional analyses conducted by E&Y for each of the eight**  
15 **vendors identified by the Staff Accounting Panel at pages 80-82?**

16 A. Yes, Exhibit \_\_ (MB-2R) sets forth E&Y's analysis and demonstrates why  
17 we believe that our risk-based sample approach was appropriate and our  
18 analysis was correct with respect to each vendor.

19  
20 **Q. Are there examples of testing performed on other specific vendors**  
21 **where the risk analysis indicated a higher level of risk that you would**

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1           **like to discuss?**

2    A.    Yes. The nature of the costs underlying the examples cited by the Staff  
3           Accounting Panel was such that it resulted in a low risk of inconsistency  
4           or error; therefore, we deemed that effective coverage of the vendor could  
5           be achieved, even with limited testing, to be able to conclude on the  
6           population for those vendors. There were other vendors where the nature  
7           of the costs made the risk higher and the level of required testing to  
8           achieve effective coverage of those vendors was much more extensive.  
9           Examples of these vendors include:

10           1.    The Portland Group Inc. (Workbook C1.171, \$9,520,197 in total  
11                   costs, 7,290 total transactions, and \$1,030,054 in total allocation  
12                   adjustments of which \$2,060 affected Niagara Mohawk Gas) – The  
13                   Portland Group Inc. is an example of a vendor similar to A F  
14                   Supply (*i.e.*, a vendor that provides gas conversion supplies whose  
15                   costs are direct charged to the appropriate business unit based on  
16                   the location the items were physically shipped to or where services  
17                   were actually provided), which was identified by the Staff  
18                   Accounting Panel and discussed in Exhibit \_\_ (MB-2R). Based on  
19                   our original assessment, we initially deemed the level of risk of  
20                   error for the vendor to be low and designed our testing  
21                   accordingly. We selected a limited sample within each of the six

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1 business units to confirm our understanding. However, we noted  
2 errors in our limited testing and deemed that full testing of all  
3 transactions for the vendor was required. Ultimately, 100 percent  
4 of invoices available for testing were reviewed for appropriate  
5 allocation of costs.

6 2. Gardner Nelson (Workbook C1.171, \$3,755,883 in total costs, 122  
7 total transactions, and \$107,642 in total allocation adjustments of  
8 which \$4,881 affect Niagara Mohawk Gas and \$32,188 affected  
9 Niagara Mohawk Electric) – Gardner Nelson is a vendor that  
10 provides marketing related services and costs were charged to the  
11 appropriate business unit based on whether the business unit  
12 ultimately benefitted from the marketing program. We determined  
13 it was necessary to test 100 percent of these transactions because  
14 there were various marketing programs benefitting multiple  
15 business units and both methods of charging (*i.e.*, direct charges  
16 and charges using bill pool/allocation codes).

17 3. Graybar Electric Company Inc. (Workbook C1.071 & C1.292,  
18 \$909,023 total cost, 2,441 in total transactions, and \$73,716 in total  
19 allocation adjustments of which \$25,800 impacted Niagara  
20 Mohawk Electric) – Graybar Electric Company Inc. is a vendor  
21 similar to Stuart C. Irby Company, which was identified by the

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1 Staff Accounting Panel, in that Graybar is also a distributor of  
2 components for the electric industry. As with Irby, the majority of  
3 Graybar transactions were small in dollar amount. Again, we  
4 decided to apply a combined sampling methodology using both  
5 judgmental key item sampling for coverage and random sampling.  
6 This approach resulted in selecting the largest invoices (*i.e.*, key  
7 items) and representative samples from the remaining population.  
8 We noted exceptions in this representative sample pool related to  
9 the purchase of rubber gloves and sleeves, and we therefore  
10 expanded our testing of transactions found to exhibit traits similar  
11 to those exceptions noted for rubber gloves and sleeves. For the  
12 testing of the roll forward period, we tested all transactions  
13 believed to have risk of similar exceptions noted in the purchase of  
14 rubber gloves and sleeves.

15

16 **Q. The Staff Accounting Panel also suggests (at 82-83) that the**  
17 **examination that E&Y performed on a number of items that it**  
18 **actually tested was not sufficient. Do you agree?**

19 A. No. As set forth below, we dispute the Staff Accounting Panel's claim  
20 with respect to each of the items that it deemed to be insufficient:

21 1. HSBC (Workbook C1.013) – P-Card Transactions

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1                   • With respect to the Staff Accounting Panel’s claim that E&Y  
2                   never reviewed actual receipts for these transactions, we  
3                   utilized other corroborating information that was sufficient to  
4                   support our conclusion. This was in the form of detailed credit  
5                   card vouchers provided to National Grid by the vendor, which  
6                   is utilized by National Grid as the basis for payment. This  
7                   equates to a detailed electronic version of a credit card  
8                   statement. Our approach was threefold: 1) to test for  
9                   completeness of the data files, 2) to utilize the total payables  
10                  amount in the credit card voucher detail from the vendor and  
11                  reconcile the charges and charged bill pool/allocation code  
12                  and/or business units to the employee charged bill  
13                  pool/allocation code and/or business units for their payroll time  
14                  charging, and 3) to test storm-related costs. We also gained an  
15                  understanding of the National Grid policies regarding P-Cards.  
16                  At the end of each month, logs detailing all transactions are  
17                  required to be completed by all employees who have a P-Card.  
18                  These transaction logs include receipts for all purchases and a  
19                  valid business purpose for the transaction. This transaction log  
20                  is approved and signed off by the immediate  
21                  supervisor/manager and sent to Accounts Payable for

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1 processing. The P-Card Program is also subject to audit by the  
2 Corporate Audit department. Any exceptions noted during the  
3 manager review and/or Corporate Audit review is subject to  
4 adjustment as part of those processes. As there are various  
5 mechanisms to check the validity of receipts, we deemed this  
6 low risk and detailed testing of the receipts was not conducted.  
7 Additionally, our testing to confirm that the employees in  
8 question were appropriately charging time to these bill  
9 pool/allocation codes further supports that there was low risk  
10 of improper inclusion of these expenses in the bill  
11 pool/allocation code, as any errors noted would have resulted  
12 in an adjustment.

13 • While the Staff Accounting Panel (at 83) concludes that three  
14 items were not tied back to the individual vouchers and  
15 therefore should have been considered unsupported, we do not  
16 believe these should be considered as errors or unsupported  
17 costs. We noted that the costs as presented on the HSBC  
18 voucher transaction detail were reported at a different level of  
19 detail than in National Grid's PeopleSoft Accounts payable  
20 ("AP") sub ledger. The HSBC voucher detail costs were  
21 "rolled up" into summary amounts before posting to the

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1 PeopleSoft AP sub ledger. We determined that National Grid  
2 used varying criteria to calculate these AP summary rolled up  
3 postings of the HSBC voucher transaction detail. For example,  
4 some detail would roll up by employee or by date, others by  
5 expense type or business unit, etc. In testing of the time to  
6 expense comparison described in Exhibit \_\_ (MB-2R), we  
7 manually sorted and filtered the HSBC voucher transaction  
8 details to tie transactions back to National Grid's AP sub ledger  
9 costs. For the three specific sample items questioned in the  
10 Staff Accounting Panel testimony, we were able to tie out the  
11 totals on an aggregate level as indicated by our transaction  
12 completeness testing coverage described in Exhibit \_\_ (MB-  
13 2R). However, because of the AP sub ledger roll up, it is not  
14 possible to tie out each invoice in the dollar total to the AP sub  
15 ledger values for those specific HSBC voucher transaction  
16 details. As the sample was judgmental based on dollar amount,  
17 E&Y appropriately selected three additional higher dollar  
18 transactions to complete sample testing.

19  
20 For all these reasons, the Staff Accounting Panel's criticisms of  
21 these transactions are incorrect and we performed adequate testing

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1 to validate our findings.

2

3 2. Pro Unlimited (Workbook C1.004) – Temporary Labor

- 4 • While the Staff Accounting Panel (at 84) contends that E&Y  
5 did not review actual transactions, we utilized other  
6 corroborating information that was fully sufficient to support  
7 our conclusion. This other corroborating information was in  
8 the form of summary contractor charge data provided to  
9 National Grid by Pro Unlimited, which is utilized by National  
10 Grid as the basis for payment. Our approach was to reconcile  
11 the contractor charge data from Pro Unlimited to the  
12 contractors' charges and charged bill pools/allocation codes  
13 and/or business units paid by National Grid. We then  
14 compared 100 percent of these charges to the contractors'  
15 managers' charged bill pools/allocation codes and/or business  
16 units for consistency. In all cases, the contractors' managers  
17 were National Grid employees. Where the bill pools/allocation  
18 codes and/or business units information did not agree, we  
19 contacted the managers to inquire about the project description  
20 and the correct accounting string to be assigned to the  
21 contractors. If necessary, we then reallocated the time as

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1 appropriate or reallocated it to non-utility operations if a proper  
2 allocation could not be determined.

3 • While the Staff Accounting Panel further criticizes E&Y for  
4 failing to remove certain Pro Unlimited items from the test  
5 year, we disagree. The two transactions in question relate to  
6 time cards for time worked in December 2010, but the  
7 payments were not processed until Calendar Year 2011. Due  
8 to the nature of the invoicing process, whereby there is a one-  
9 month lag for receipt of invoices from Pro Unlimited and  
10 because the volume of transactions is relatively similar  
11 throughout the year, only 12 months of data were included in  
12 the Historic Test Year. Therefore these two transactions do not  
13 require an adjustment to the Historic Test Year as described by  
14 the Staff Accounting Panel.

15

16 For all these reasons, the Staff Accounting Panel's criticisms of E&Y's  
17 analysis of these transactions are unfounded and incorrect.

18

19 **Q. Are there any other specific comments from the Staff Accounting**  
20 **Panel testimony that you would like to discuss?**

21 A. Yes. As noted in our original report, we were not engaged to conduct a

**Rebuttal Testimony of Michael E. Barrett**

1 review of capital expenses, only service company O&M charges.

2

3 **Q. If you did not review capital expenses, did you infer conclusions about**  
4 **the entirety of Historic Test Year expenses, including capital expense?**

5 A. No, our conclusions are on the accuracy of the service company O&M  
6 charges only. Contrary to the suggestions of the Staff Accounting Panel  
7 and Mr. Schuler, the fact that we did not review capital expenses in no  
8 way detracts from the accuracy of our review of O&M charges. The  
9 review of O&M charges was completely independent of a review of  
10 capital charges.

11

12 **Q. Does this conclude your rebuttal testimony?**

13 A. Yes.



**Rebuttal Testimony of Michael E. Barrett**

**List of Exhibits**

- Exhibit \_\_ (MB-1R)      Analysis of the Impact of Transactions Discussed by  
the Staff Accounting Panel on Niagara Mohawk's Test  
Year Expenses
- Exhibit \_\_ (MB-2R)      Analysis of the Transactions Discussed by the Staff  
Accounting Panel



**Case 12-E-0201**  
**Case 12-G-0202**

**Rebuttal Testimony of Michael E. Barrett**

Exhibit \_\_ (MB-1R)

Analysis of the Impact of Transactions Discussed by the Staff Accounting Panel  
on Niagara Mohawk's Test Year Expenses

Analysis of Vendor Charges

Discussed by the Staff Accounting Panel

On NMPC Test Year Results

#	Workbook Ref	Vendor	Total Charges	Total Transactions	Original Allocation to NMPC			Allocation Adjustments <sup>1</sup>		
					NMPC Electric	NMPC Gas	NMPC Total	NMPC Electric	NMPC Gas	NMPC Total
1	C1.184	AF Supply	\$3,357,997	4,254	\$-	\$-	\$-	\$-	\$-	\$-
2	C1.013	HSBC Corporate Card Services	\$8,202,485	7,127	\$3,343,252	\$429,334	\$-	\$(955)	\$(163)	\$(1,118)
3	C1.182	Blackman, Inc.	\$3,408,255	8,431	\$43	\$10	\$-	\$-	\$-	\$-
4	C1.178	FW Webb CO	\$4,634,857	4,013	\$-	\$-	\$-	\$-	\$-	\$-
5	C1.047	Stuart C Irby Company	\$1,002,001	1,465	\$670,945	\$-	\$-	\$(14,709)	\$-	\$(14,709)
6	C1.001	Energy Federation Inc.	\$21,126,202	1,485	\$-	\$-	\$-	\$-	\$-	\$-
7	C1.008	Action Inc	\$4,792,649	251	\$-	\$-	\$-	\$-	\$-	\$-
8	C1.010	Conservation Services Group Inc.	\$4,208,980	301	\$-	\$-	\$-	\$-	\$-	\$-
<b>TOTALS</b>			<b>\$50,733,426</b>	<b>27,327</b>				<b>\$(15,664)</b>	<b>\$(163)</b>	<b>\$(15,827)</b>

<sup>1</sup> The allocation adjustments are the amounts adjusted out of Niagara Mohawk's cost of service before application of general inflation of 4.2785% for the Rate Year.



**Case 12-E-0201**  
**Case 12-G-0202**

**Rebuttal Testimony of Michael E. Barrett**

Exhibit \_\_ (MB-2R)

Analysis of the Transactions Discussed by the Staff Accounting Panel

### **Description of E&Y's Testing Methodology For Transactions Identified By Staff Accounting Panel**

1. A F Supply – A F Supply is a vendor that provides gas conversion supplies. Costs associated with A F Supply are direct charged to the appropriate business unit based on the location the items were physically shipped to or where services were actually provided. As such, we determined that all of the charges for 2011 were charged directly to two business units (both legacy KeySpan companies) and confirmed that this was correct with the process owners. Based on this analysis and the fact that there were over 4,200 transaction line items of a similar nature, we deemed the level of risk of error to be low and designed our testing accordingly. We selected a limited sample within each of the two business units (*i.e.*, total of four transactions) used to confirm our understanding. We did not find any errors in the allocation of cost and therefore concluded that the costs associated with this vendor were allocated appropriately to the business units in question. As we believe the sample selected was representative of the population of transactions and no errors were identified in the sample, it was reasonable to apply the same conclusion to the population of transactions. In accordance with our risk based approach, as we tested other vendors with transaction characteristics similar to A F Supply (*e.g.*, Blackman Inc, FW Webb CO, *etc.*) throughout our testing period, we reduced our sample sizes for those vendors consistent with how we sampled for A F Supply.
  
2. HSBC Corporate Card Services – HSBC is a vendor that supplies purchasing cards (P-cards) to National Grid for use by employees for day-to-day purchases as well as storm-related activities. These P-Cards are utilized to buy “low dollar” goods that cannot be purchased via other buying channels. We determined that due to the nature of use of procurement cards, we could conclude the cost is allocated appropriately by performing the following procedures:
  - *Transaction Completeness Testing*: We judgmentally selected a sample of 25 line items from the PeopleSoft database based upon dollar value (getting approximately 25% coverage of HSBC costs). We then tied these PeopleSoft line items back to the HSBC P-card transaction files. The purpose of performing this step was to reasonably conclude that the data from HSBC transactions were accurately being captured in PeopleSoft. We also agreed the files in total, only noting some immaterial differences, thereby validating completeness of the files.
  - *Payroll to Cost Comparison*: We judgmentally selected a sample of 25 line items from the PeopleSoft database based upon dollar value. This resulted in testing of approximately \$365,000 of total transactions or approximately 5% of the total population of dollars for the vendor. From within the judgmental sample of 25 line items, we identified the employees responsible for the P-card transactions. We compared the employee's PeopleSoft payroll allocations with the P-card expense allocations, and concluded on each sample as to whether or not the P-cards were appropriately being used and expensed by the employees. We also confirmed the charging with the employee directly where necessary. In instances where the bill pool/allocation code and/or business

**Description of E&Y's Testing Methodology  
For Transactions Identified By Staff Accounting Panel**

unit information did not agree, we contacted the employee and/or employee's manager to determine if the bill pool/allocation code required adjustment. The purpose of performing this step was to reasonably conclude that procurement card charges were in line with employee payroll allocations. As we did not note any exceptions, further testing was not deemed necessary.

- *Storm Costs Coverage:* As storm costs follow storm accounting as opposed to normal employee payroll cost allocations, we identified all storm charges, and followed up with management on the allocation codes utilized in expensing storm P-card charges. We selected 100% of these costs for allocation testing. This resulted in testing of approximately \$680,000 of total transactions or approximately 8% of the total population of dollars for the vendor. We performed this step to reasonably conclude that storm charges were allocated to the appropriate businesses based on the storm in question.
3. Blackman, Inc. – Blackman, Inc. is a vendor that provides gas conversion supplies. Costs associated with Blackman, Inc. are direct charged to the appropriate business unit based on the location the items were physically shipped to or where services are actually provided. As such, we determined that all of the charges for 2011 were charged directly to three business units (all legacy KeySpan companies) or used an allocation code based on the building location and confirmed that this was correct with the process owners. Based on this analysis and the fact that there were over 8,400 transaction line items of a similar nature, we deemed the level of risk of error to be low and designed our testing accordingly. We selected a limited sample within each of the three business units and the allocation code based on building location used to confirm our understanding (*i.e.*, total of 16 transactions). We did not find any errors in the allocation of cost and therefore concluded that the costs associated with this vendor were allocated appropriately to the business units in question and that no additional testing was needed.
  4. F W Webb CO – F W Webb CO is a vendor that provides gas conversion supplies. Costs associated with F W Webb CO are direct charged to the appropriate business unit based on the location the items were physically shipped to or where services are actually provided. As such, we determined that all of the charges for 2011 were charged directly to six business units (all legacy KeySpan companies) and confirmed that this was correct with the process owners. Based on this analysis and the fact that there were over 4,000 transaction line items of a similar nature, we deemed the level of risk of error to be low and designed our testing accordingly. We selected a limited sample within each of the six business units (*i.e.*, total of eight transactions) used to confirm our understanding. We did not find any errors in the allocation of cost and therefore concluded that the costs associated with this vendor were allocated appropriately to the business units in question and that no additional testing was needed.

**Description of E&Y's Testing Methodology  
For Transactions Identified By Staff Accounting Panel**

5. Stuart C Irby Company – Stuart C Irby Company (“Irby”) is an electrical distributor of a variety of electrical products to serve their clients, including commercial entities, independent contractors, and utilities such as National Grid. Irby had over 1,400 line items of consistently low dollar amounts in the population that were charged directly to eight different business units (combination of legacy National Grid and legacy KeySpan companies). The majority of these charges were for small parts and tools including such items as safety gloves. Because of the wide variety of charging to multiple business units, we decided to apply a combined sampling methodology incorporating both judgmental key item sampling for coverage and random sampling. This approach resulted in selecting the largest invoices (*i.e.*, total of 17 invoices) and representative samples (*i.e.*, total of 24 invoices) from the remaining population. We noted an exception during testing of the interim period related to the purchase of rubber gloves and sleeves. As a result, we expanded our sample for the interim period, and for the testing of the roll forward period, we chose to test all invoices that could potentially result in similar exceptions. For the interim period, we judgmentally selected an additional sample of items, based on the previously identified exceptions, (*i.e.*, total of 73 invoices) noting no further exceptions and concluded the testing was sufficient for this vendor for this period. For the testing of the roll forward period, we tested all transactions found to be at risk of having similar exceptions. This resulted in testing of 100% of the transactions in the roll forward period.
6. Energy Federation Inc. – Energy Federation Inc. provides services related to energy efficiency rebate programs. We note that any expenses incurred by National Grid for these vendors are presented as a separate line item during the rate case process and not included as part of the cost of service. Costs associated with Energy Federation Inc. are direct charged to the appropriate business unit based on the location to which the rebates relate. As such, we determined that all of the charges for 2011 were charged directly to eight business units (mainly legacy KeySpan gas companies) and confirmed that this was correct with the process owners. Based on this analysis, we deemed the level of risk of error to be low and designed our testing accordingly. We selected a limited sample (*i.e.*, total of two transactions) used to confirm our understanding. We did not find any errors in the allocation of cost and therefore concluded that the costs associated with this vendor were allocated appropriately to the business units in question and that no additional testing was needed. In accordance with our risk based approach, as we tested other vendors similar to Energy Federation Inc. (*e.g.*, Action Inc., Conservation Services Group, Inc., *etc.*) throughout our testing period, we reduced our sample sizes for those vendors consistent with how we sampled for Energy Federation Inc.
7. Action Inc. – Action Inc. provides services related to energy efficiency rebate programs. We note that any expenses incurred by National Grid for these vendors are presented as a separate line item during the rate case process and not included as part of the cost of service. Costs

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- associated with Action Inc. are direct charged to the appropriate business unit based on the location the rebates relate to. As such, we determined that all of the charges for 2011 were charged directly to five business units (legacy KeySpan gas companies) and confirmed that this was correct with the process owners. Based on this analysis, we deemed the level of risk of error to be low and designed our testing accordingly. We selected a limited sample (*i.e.*, total of 64 transactions) used to confirm our understanding. We did not find any errors in the allocation of cost and therefore concluded that the costs associated with this vendor were allocated appropriately to the business units in question and that no additional testing was needed.
8. Conservation Services Group Inc. - Conservation Services Group Inc. provides services related to energy efficiency rebate programs. We note that any expenses incurred by National Grid for these vendors are presented as a separate line item during the rate case process and not included as part of the cost of service. Costs associated with Conservation Services Group Inc. are direct charged to the appropriate business unit based on the location to which the rebates relate. As such, we determined that all of the charges for 2011 were charged directly to seven business units (legacy KeySpan gas companies) and confirmed that this was correct with the process owners. Based on this, we deemed the level of risk of error to be low and designed our testing accordingly. We selected a limited sample (*i.e.*, total of 99 transactions) used to confirm our understanding. We did not find any errors in the allocation of cost and therefore concluded that the costs associated with this vendor were allocated appropriately to the business units in question and that no additional testing was needed.