Ex 82

PREPARED REBUTTAL TESTIMONY

OF

NATIONAL GRID'S RELIABILITY PANEL

CHERYL A. WARREN

DAVID WRIGHT

SCOTT LEUTHAUSER

KEITH MCAFEE

ON BEHALF OF

NATIONAL GRID plc

AND

KEYSPAN CORPORATION

CASE 06-M-0878

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RELIABILITY PANEL

I. Introduction and Qualifications

Q. Ms. Warren, please state your full name and business address.

A. Cheryl A. Warren, 1125 Broadway, Albany, NY 12201.

Q. Please state your position with the Company.

A. I am the Director of Asset Strategy and Performance in the Distribution Engineering and Asset Management organization within the National Grid USA Service Company, Inc. The Distribution Engineering and Asset Management organization provides support to Niagara Mohawk Power Corporation d/b/a National Grid ("National Grid" or "Company") on all technical and other support matters. My responsibilities as Director of Asset Strategy and Performance include provision of reliability assessment support, development of the reliability enhancement program (REP), and preparation of reliability results for regulatory filings.

Q. Please describe your educational background and training.

A. I received a Bachelor of Science Degree in Electrical Engineering in 1987 and a Master of Science in Engineering in 1990 from Union College in Schenectady, NY. I have lived in the Capital District region for most of my life.

Q. Please describe your professional experience.

A. I was employed by Central Hudson Gas and Electric from 1987 to 1989 in the System Protection Department where I was responsible for relay coordination on

the distribution system. In 1990, I accepted a position in the Distribution Engineering Group, part of the Consulting Group, with Power Technologies Inc. ("PTI"). My responsibilities included the study and analysis of distribution issues for numerous companies. My primary areas of responsibility were in power quality and reliability studies for clients. During this timeframe, I also assisted on the Rocket Triggered Lightning project that was sponsored by the Electric Power Research Institute ("EPRI"), and taught numerous courses on distribution systems, protection and coordination, and reliability analysis. In 1995, I transferred into the Software Group at PTI and assumed leadership of its distribution power flow software package (PSS/U). In that role I was responsible for all aspects of the program, including design, implementation, testing, training, support, manual creation, sales, marketing and user groups. In 1998, I transferred back to the Consulting Group where I was largely responsible for leading distribution reliability and information technology ("IT") integration engagements for clients. In 1999, I accepted a position as a Senior Engagement Manager with Navigant Consulting in Albany, NY. There I led reliability and IT system integration client engagements. In August 2002, I accepted my present position with National Grid USA.

Q. Please outline your professional activities.

A. I have participated extensively in the Institute of Electrical and Electronics

Engineers, Inc. ("IEEE") activities, which is the electrical engineering standards-making body in the United States. As part of IEEE, I have led the Working Group on System Design that has been renamed to the Working Group on Distribution Reliability ("Working Group") since 1990. This Working Group is the author of IEEE Std. 1366-2003, the *Guide for Electric Power Distribution Reliability Indices*. I am also the Chair of the IEEE Power Engineering Society Distribution Subcommittee. In June 2007, I will receive the IEEE PES Excellence in Power Distribution Award. I have authored and co-authored twenty-eight papers and spoken at numerous conferences on distribution reliability, power quality and IT integration issues.

Q. Have you previously testified before the Commission?

A. No, I have not.

Q. Mr. Wright, please state your full name and business address for the record.

A. My name is David Wright. I am employed by National Grid, and my business address is 25 Research Drive, Westborough, MA 01582.

Q. Please state your position within the Company?

A. I am Vice President Transmission Asset Management. The Transmission Asset Management organization parallels the Distribution Engineering & Asset Management group and provides support to National Grid in New York with respect to transmission assets. In that capacity I am responsible for 115kV and

above assets (69kV and above in New England) on National Grid's transmission system. This includes the development of policies and processes used to manage the transmission system; understanding the condition, age, and life cycle of our assets; planning for the future needs of the transmission system; investment in and maintenance of our transmission system, and evaluating risks to the system to ensure optimum service provision to our customers over the whole lifetime of the asset.

Q. What is your educational background?

A. I was educated in the United Kingdom. I graduated from Birmingham University in 1990 with a Bachelor of Science in Electrical and Electronic Engineering. I am a dual Chartered Engineer in both electricity and gas with the Institute of Engineering and Technology (IET) and the Institute of Gas Engineering Managers (IGEM).

Q. Please summarize your professional experience.

A. I joined National Grid in 1992 as an engineer in Grid System Management in the United Kingdom. In 1994 I was transferred to the national control centre where I undertook a variety of roles including a period on shift as a reactive management engineer. In 1999 I was appointed to my first of three managerial roles as the business was re-organized from a regional to a national model in which I became the Transmission Requirements Manager responsible for the operational planning

of the UK's England and Wales transmission network. In 2003 I transferred to gas and became the Strategy & Support manager for the UK's gas transmission control function. In 2005 I moved into Asset Management as the senior manager for Planning including responsibility for derivation of all work plans, the management of 40,000 annual rental and easement grantors and the management of safety for the system. In 2006 I was appointed to my current position as Vice President for transmission asset management for National Grid's US businesses in New York and New England.

Q. Have you previously testified before the Commission?

A. No, I have not.

Q. Mr. Leuthauser, please state your full name and business address for the record.

A. My name is Scott D. Leuthauser. I am employed by National Grid, and my business address is 300 Erie Blvd West, Syracuse, NY 13202.

Q. What is your educational background?

A. I am a licensed engineer in New York State. I graduated from Clarkson University in 1986 with a Bachelor of Science in Mechanical Engineering. In 1989, I received a Masters of Business Administration from State University of New York at Buffalo and in 2004 received a Masters Certificate in Power Systems Management from Worcester Polytechnic Institute.

Q. In what capacity are you employed at National Grid?

A. I am Vice President Project Management. In that capacity I am responsible for the supervision of professionals who provide management of electric distribution and substation projects for National Grid.

Q. Please summarize your professional experience.

A. I joined National Grid in 1986 as a Junior Engineer in Fossil Generation. In 1987 I was transferred to the C.R. Huntley Steam Station where I served as the station performance engineer and Assistant Station Shift Supervisor. In 1990 I was transferred to work as a Senior Fuel Supply Analyst. In 1993 I became a Senior Supply Planner in Supply Planning and shortly thereafter was promoted to Manager of Supply Planning. In 1997 I became Manager Supply (Power) Contracts, then, in 1998 was promoted to Director of Energy Transactions (power contracts, rates, and load research). In 2002, I was promoted to Vice President Distribution Planning & Engineering and in 2005, to Vice President Distribution Investment Management, and in August 2006 to Vice President Project Management.

Q. Have you previously testified before the Commission?

A. Yes, I have previously testified in proceedings pertaining to Long Run Avoided Costs, several rate case proceedings including supporting testimony to PowerChoice, the Merger Rate Plan, and Standby Service Rates. I submitted

testimony in connection with the Company's March 2006, Petition for Rate Relief in Case 04-M-0159, seeking recovery of costs incurred to implement stray voltage testing and facilities inspection programs, and most recently testified in the Deferral Audit case as part of 01-M-0075.

Q. Mr. McAfee, please state your name and business address for the record.

A. My name is Keith P. McAfee. I am employed by National Grid, and my business address is 1125 Broadway, Albany, NY 12204.

Q. What is your educational background?

A. I am a licensed engineer in New York State. I graduated from Clarkson University in 1985 with a Bachelor of Science in Electrical Engineering. I received a Masters of Business Administration from New Hampshire College in Manchester, New Hampshire in 1991.

Q. In what capacity are you employed at National Grid?

A. I am Director of Customer Operations for the Eastern Division. In that capacity I am responsible for the supervision of professionals and field forces that provide maintenance and construction of the Company's electric infrastructure in that area.

Q. Please summarize your professional experience.

A. I joined National Grid in 1992 as an Account Manager in Buffalo, NY. In 1994, I was promoted to Technical Services Manager in Albany, NY. In 1999, I was

promoted to Regional Manger for the Northeast Region in Glens Falls, NY. In 1999, I was promoted to my present position as Director of Customer Operations for the Eastern Division. Prior to National Grid, I was employed by Central Hudson Gas and Electric from 1985 through 1987 as an Associate Engineer in Newburgh, NY. Between 1987 and 1991, I held various operations management and engineering positions for Public Service Company of New Hampshire in Manchester and Nashua, NH.

Q. Have you previously testified before the Commission?

A. No, I have not.

Q. What exhibits are the Panel Witnesses sponsoring in support of this testimony?

A. The Reliability Panel is sponsoring the following exhibits:

Exhibit No. __ (Reliability Panel-1R) – Charts, Graphs and Tables

Exhibit No. __ (Reliability Panel-2R) – Summary of IR DPS-281

Exhibit No. __ (Reliability Panel-3R) – New York Lineworker Staffing

Exhibit No. __ (Reliability Panel-4R) – Table from IR DPS-281

Exhibit No. __ (Reliability Panel-1S) – Update State SAIFI and CAIDI Data

II. Purpose of Testimony

Q. What is the purpose of the Reliability Panel's testimony as it relates to the Company's filing?

A. The purpose of our testimony is to address various concerns raised by Department

of Public Service Staff regarding electric reliability, electric line workforce, and the maintenance backlog. Similar concerns regarding electric reliability were also raised by the Consumer Protection Board ("CPB"), IBEW Local 97 ("Local 97") and UWUA. In addition, Local 97 also raises concerns regarding system reliability and believes that the degradation in service is due to a reduction in operating staff. Our testimony is organized as follows:

- an explanation of the investment National Grid plans to make in New York and a description of programs that have been implemented by the Company to address the root causes impacting reliability performance;
- an analysis of the Company's performance as measured by CAIDI and SAIFI;
- an analysis of the Company's performance as compared to other utilities' in New York and nationally;
- a response to the assertions made by Witness Reulet concerning the maintenance backlog; and
- the various efforts that have been undertaken post-merger to improve transmission reliability within New York State.

We will also respond to Staff~~and the Unions~~' concerns about the electric line workforce, specifically:

- the Company's staffing to respond to customer outage events (herein "trouble") resulting from a typical day's weather and from weather storm

Since we filed this testimony, National Grid has reached agreement with Local 97 and the UWUA on terms that allows them to support the merger.

events (e.g., wind, lightning, snow, ice);

- the Company's current staffing levels relative to levels at the time of the merger between Niagara Mohawk and National Grid (more specifically calendar year 2001 versus 2006); and
- the Company's staffing plans and strategies to retain and sustain qualified workers (internal and external) prospectively to respond to trouble and complete the work outlined in the business plan.

III. Reliability Panel Rebuttal to Staff ~~and Union~~ Testimony

Q. Does National Grid recognize that there is an issue with electric reliability with respect to its New York State system?

A. Yes. National Grid recognizes that electric reliability with respect to its New York assets needs to improve. National Grid takes electric reliability very seriously and has spent significant resources on capital investments and maintenance in New York since the merger.

Q. Please explain.

A. From the moment the Niagara Mohawk acquisition was completed, National Grid has been committed to a strong program of investment in and maintenance of its NY Transmission and Distribution ("T&D") infrastructure.

Q. How do these expenditures compare with the merger rate settlement?

A. As summarized in the response to DPS-281, Exhibit No. __ (Reliability Panel-

4R), National Grid's annual capital expenditures in this regard during the first three years after the merger averaged 40% higher than the level that had prevailed in the six years before the merger. Exhibit No. ___ (~~Reliability~~ Rates Panel-4R) of ~~Mr. Laflamme's and~~ Mr. Molloy's testimony shows that National Grid has invested more capital in the system than was included in the rate plan. Specifically, National Grid's total 2002 to 2006 capital expenditures were more than 55% higher than those anticipated in the rate plan. Similarly, referring to Exhibit No. ___ (Reliability Panel-4R), our total 2002-2006 O&M expenditures were more than11% higher than if we held the expenditures to pre-merger levels, again adjusted for inflation.

Q. **Please summarize the approach National Grid is taking to ensure acceptable reliability performance on its electric transmission and distribution system?**

A. In addition to this commitment of resources, National Grid needed to improve its reliability results and the way it managed its assets. Dedicated asset management teams were established to improve the long-term performance and health of our assets and in 2004, the Company began to actively develop a program to return service quality to what it believed to be more acceptable levels. The results of these efforts were a Reliability Enhancement Program for distribution ("REP") and a portfolio of asset strategies to improve the reliability performance of the transmission system. Over the five year period starting with the current fiscal

year, the REP will add $360 million of capital and maintenance expenditures to baseline distribution reliability spending of $260 million, producing a total of $620 million committed to the reliability of distribution infrastructure. In addition, asset management strategies have yielded a targeted transmission capital plan of $576 million for the same five year period. When one adds other capital expenditures anticipated for the distribution system and projected transmission maintenance expenditures, the total planned capital investment and maintenance expenditures for the transmission and distribution infrastructure are expected to be $1.82 billion ($1.47 billion capital and $350 million maintenance), compared to an expenditure of $1.0 billion for comparable purposes in the previous five-year period. Exhibit No. __ (Reliability Panel-2R) outlines the year by year history and projections by major category.

These plans are continually being reviewed and updated to improve the efficiency of our investments based on the latest asset condition, reliability performance data and customer satisfaction results.

Q. Before describing National Grid's reliability-related programs in greater detail, please summarize the Company's recent reliability results. Does National Grid agree with the data provided in Witness Reulet's charts at DFR-1 and DFR-2?

A. There are some discrepancies between DFR-1 and DFR-2 and the performance

indices that Niagara Mohawk filed in its annual reliability filings. The reported SAIFI for calendar year 1997 was 0.93 and for 1999 was 0.94. The reported CAIDI for 1998 was 2.03, for 1999 was 1.87, for 2001 was 1.89, for 2003 was 1.99, and for 2005 was 2.33. The differences are minimal, but for the sake of accuracy, please see Figure 1 (Reliability Panel-1R) and Figure 2 (Reliability Panel-1R) below.

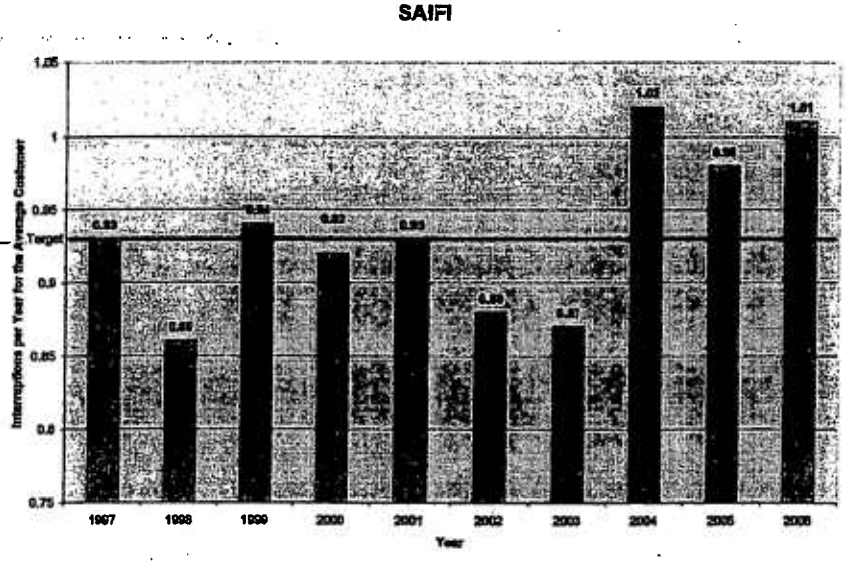

Figure 1. SAIFI - DFR-1

CAIDI

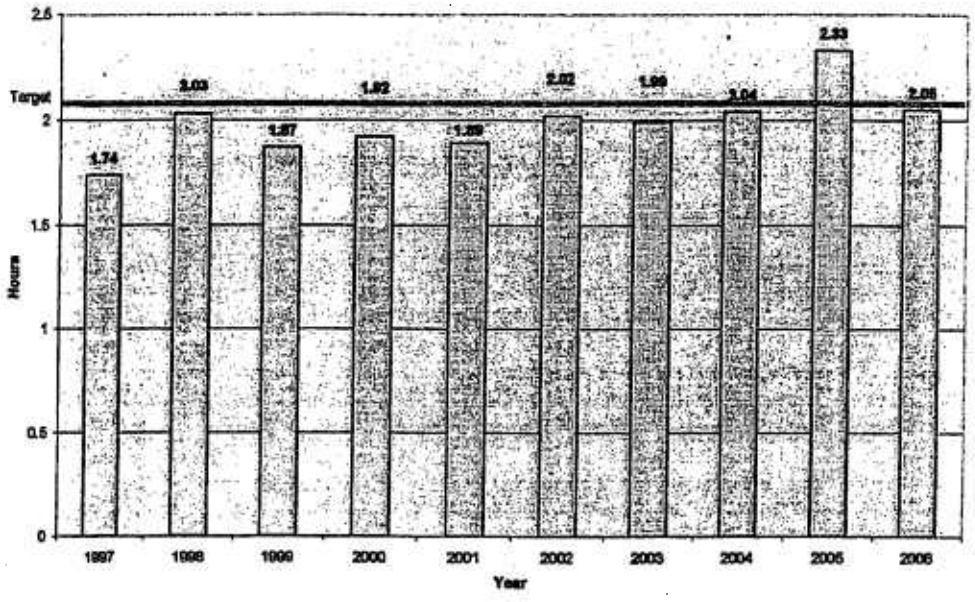

Figure 2. CAIDI - DFR-2

Q. Please provide a brief description of the Company's reliability performance since the time of the merger.

A. Following National Grid's merger with Niagara Mohawk, the Company has met the CAIDI target in all years except 2005, when CAIDI was an abnormally high 2.33 hours.

Notice that in all the other years CAIDI fluctuates around 2.03 hours. While there has been a minor degradation in performance since 2002, there is not a significant increasing trend. In fact, contrary to Witness Reulet at p. 8 lines 10-14, had 2005 not been an abnormal year, the CAIDI trend would have been flat and the five

year average would have been 2.02 hours.

In 2005, the Company experienced numerous subtransmission events on our radial subtransmission lines; two examples are in the Schroon – Chestertown area and in the Old Forge – Racquette Lake area. Because customers are served from radial lines (only one source of power) in these remote Adirondack areas, long duration events occurred.

Even though CAIDI rose to 2.33 in 2005 only, the Company took proactive measures to ensure that better performance results were achieved in 2006. The proactive measures included the implementation of one person crews, alternate off-shift schedules, proactive work practices such as performing extra feeder patrols and fixing the items found, and increased the number of crews held for weather events. The Company also performed additional vegetation management ("VM") activities including tree trimming and hazard tree removal as well as adding 25 more reclosers to the system to improve performance. The Company spent nearly $1.6 million incremental dollars to accomplish the additional VM and nearly $1 million on the additional reclosers.

Q. Why did the Company exceed the SAIFI target in 2004, 2005 and 2006?

A. There were three main reasons the Company exceeded the SAIFI target. They were: (i) increased tree-related and deteriorated equipment/lightning interruptions; (ii) abnormal weather; and (iii) changes in data recording.

Q. Please further describe the impact of the tree-related interruptions, deteriorated equipment/lightning interruptions and weather on SAIFI performance.

A. Reviewing root cause information presented in Figure 3 (Reliability Panel-1R) below, the key performance drivers are interruptions caused by trees, distribution equipment and subtransmission events.

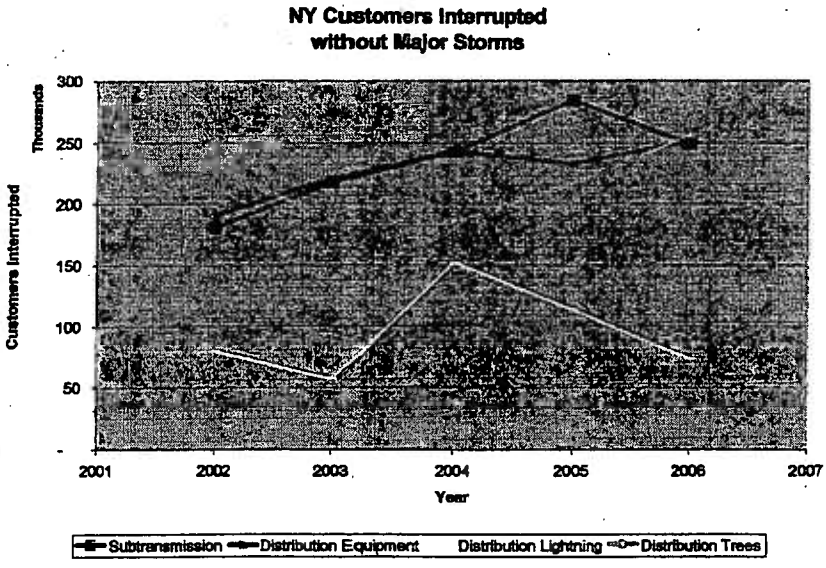

Figure 3. Some of the Major Causes of SAIFI Increase

In 2004 and to some degree in 2005, the Company experienced an abnormally high amount of lightning striking the service territory as can be seen in Figure 4 (Reliability Panel-1R) below.

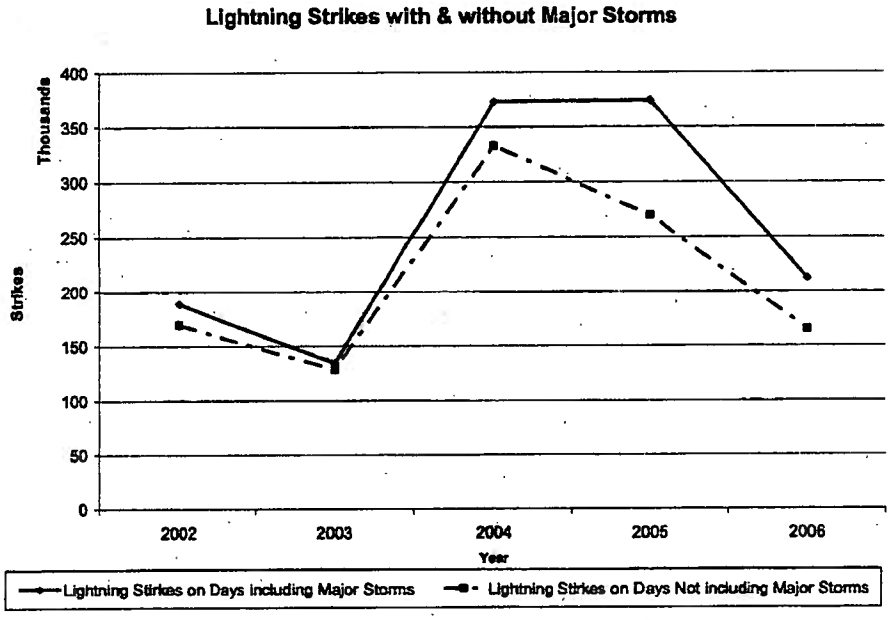

Figure 4. Number of Lightning strikes to the National Grid Service Territory per the Vaisala Lightning Detection Network

Not only was there an abnormally high amount of lightning strikes during major storm events, but also during non-major storm days. Lightning can strike near power system equipment without causing an immediate interruption to customers. In certain cases, these strikes can weaken the infrastructure and ultimately result in conditions that lead to an interruption that occurs at a later time. For example, extruded distribution cables frequently fail during or shortly after a thunder storm.[1] Transformers have also failed after lightning storms.[2] The

1 "Effects of voltage surges on extruded dielectric cable life project update"
Hartlein, R.A. Georgia Power Co., Atlanta, GA, USA ; This paper appears in: Power Delivery, IEEE

later interruption is attributed to deteriorated equipment because it cannot be definitively traced to lightning. These interruptions would contribute to a rise in SAIFI.

Between 2004 and 2006, the Northeast US has experienced different weather patterns than in other years. For example, in 2004, the Northeastern United States experienced a much colder than average summer, and in 2005, experienced a record wet October and heavy rain and flooding in April, and in 2006, experienced the wettest summer on record as well as record snow fall in New York city (February) and Buffalo (October).[3]

Consistent with these weather patterns, rainfall in the northeast region of the service territory was above average from 2004-2006. In 2004, a portion of I-87 above exit 23 washed away in June. In 2006, it was the wettest year on record. The rain fall, combined with less snow and cold weather, has provided a longer growing season for trees. In addition, the ground remained unfrozen for the majority of the winter months contributing to a high incidence of tree uprooting

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INSPEC Accession Number:4718372 Digital Object Identifier: 10.1109/61.296236 Posted online: 2002-08-06 19:25:34.0

2 "Reduction in distribution transformer failure rates and nuisance outages using improved lightning protection concepts" Cooper Power Syst., Pewaukee, WI, USA ; This paper appears in: Power Delivery, IEEE Transactions on
Publication Date: April 1995 Volume: 10 , Issue: 2 On page(s): 768 - 777 ISSN: 0885-8977 CODEN: ITPDE5
INSPEC Accession Number:4954031 Digital Object Identifier: 10.1109/61.400854 Posted online: 2002-08-06 19:44:26.0

due to the soft soil conditions. In January and February of 2006, the Company experienced the highest levels of customers interrupted due to tree-caused interruptions recorded for each of those two months in eight years.

We anticipate that tree-related interruptions will accelerate in the Buffalo area in 2007 and 2008 due to the October 2006 snow storm. Many of the trees affected by the Buffalo storm were severely damaged and could continue to drop limbs over that time period. The Company took a proactive approach to resolving certain of these VM issues and spent three months and $6.258 million performing additional vegetation work in the areas hardest hit by the recent Buffalo snow storm. The post storm hazard mitigation work focused on removing uprooted and leaning trees, broken limbs and storm damaged vegetation from above three phase primary lines on fifty-nine (59) circuits within the original storm footprint area. The majority of work was concentrated in backyard areas and required more than sixty (60) climbing crews, all supplemental to the crews performing our normal maintenance for the year. In addition, four (4) additional contract arborists were hired to supplement National Grid's management team on this process. Part of the project also included some work on transmission rights-of-way in the same area where edge tree damage was mitigated to prevent future outages.

During 2004 through 2006, the number of customers affected by

3 Source: National Climatic Data Center (http://www.ncdc.noaa.gov/oa/climate/research/monitoring.html)

subtransmission interruptions was higher than in previous years. The root causes of subtransmission interruptions are shown below in Figure 5~~Figure 5~~~~Figure 5~~ (Reliability Panel-1R).

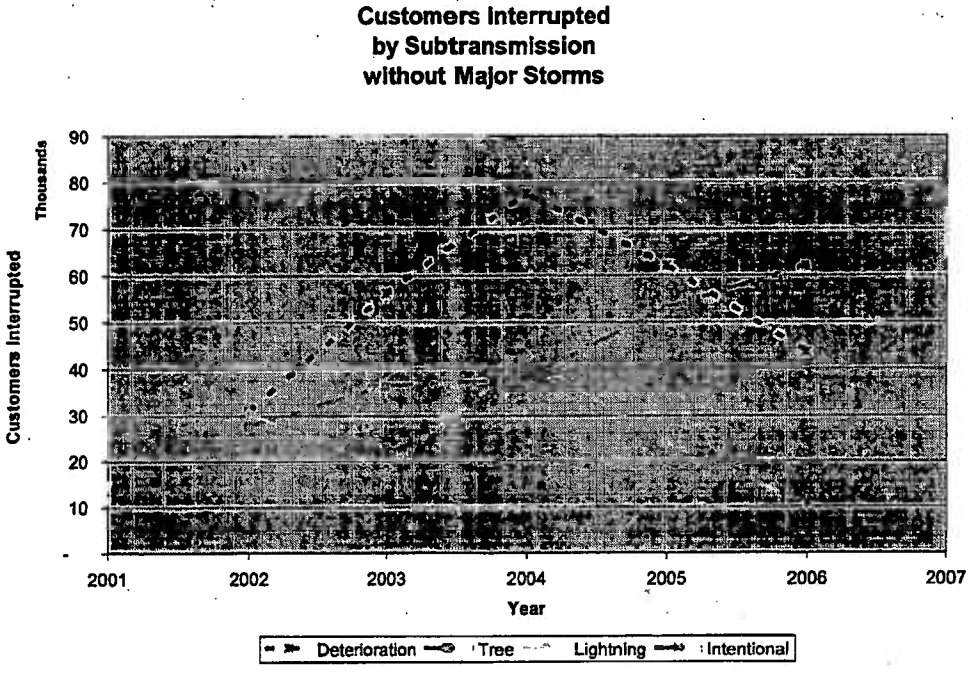

Figure 5. Customers Interrupted by Subtransmission Interruptions

As can be seen, lightning and deterioration are tracking on the same trend in 2004 – 2006. Tree related interruptions have been steadily rising because of the reasons outlined above. The Company is taking a proactive approach to widening the rights of way on the subtransmission system and currently plans to widen about 1,000 miles of subtransmission rights of way by 2011.

Q. Did intentional interruptions (i.e., planned maintenance) contribute to SAIFI in 2006?

A. Yes, the number of customers affected by intentional interruptions increased in 2006. These interruptions are consistent with good utility practice and necessary to complete required work however, they do contribute to the decline in reliability performance. The subtransmission capital budget has been more than doubled above the current rate plan to address load, asset replacement and reliability issues. These projects along with continued widening of the ROWs should make a significant positive impact on reliability over time.

Q. Can changing the interruption data collection methods affect reported performance on reliability indices?

A. Yes. Utilities across the nation that have been changing their outage management processes and their associated IT systems have experienced changes in their reported indices, which are considered inconsistent with their actual underlying reliability performance. Legacy outage management systems were implemented to assist operators with power restoration. As industry restructuring occurred, reliability index tracking became the mainstay of distribution regulation and hence the need for very accurate information from legacy systems became imperative. Since these systems were not originally designed for this purpose, they did not provide this extremely accurate information. As utilities move to improve

processes and replace legacy systems, in most cases they experience an index rise between 25% and 75% from previous numbers. A few have seen even higher rises. The Company does not yet know what impact the enhanced capabilities of the new system will have on future reliability statistics. However, it is possible that National Grid will see increases in reported SAIFI and CAIDI independent of actual underlying system performance, as has been the case at other utilities who have implemented similar systems.

The main sources of error in the legacy systems stem from: (i) missing events – those not captured in the system; (ii) lack of accurate numbers for customers interrupted – many legacy systems were paper-based and relied on field estimates for customers interrupted or did not have fully connected GIS models that help to provide accurate customer counts; (iii) lack of accurate recording of duration of events – legacy systems depend on the time the first customer calls to begin an event and the time the line personnel reports the end of the event; (iv) training – when new systems are implemented there is often a steep learning curve for those using it and the initially collected data often has numerous errors – these are corrected over time with experience and training.

Q. What type of system does National Grid use to collect interruption information?

A. Since 1993, interruption data has been collected in the legacy, paper-based system

interruption reporting (SIR) system. Historical results from this legacy system were used to develop the reliability performance targets contained in National Grid's existing rate plan. SIR is the system used to collect the information that is reported to the Public Service Commission, even today. This system relies on line personnel to: (i) fill out the trouble tickets; (ii) correctly estimate the customers affected; and (iii) report the interruption completed times.

For the reasons stated above, results from the legacy SIR system could have been affected by the types of errors described previously. During the hectic activity surrounding the restoration efforts of major and minor storms, it is possible that interruption tickets may have been misplaced and not entered into the system.

Q. Does National Grid plan to upgrade their paper-based system to a new state-of-the-art system?

A. Yes. National Grid plans to use GE's PowerOn product in the future, although it should be noted that National Grid is not reporting reliability results using this system in 2006. National Grid has been running its SIR system in parallel with its newly implemented PowerOn system, which has been tightly integrated with its interruption disturbance system (IDS) since April, 2004. In this time period, it is likely that some of the more accurate information now more readily available due to the PowerOn system is also being entered into the legacy system thereby

accounting for some of the rise in reported SAIFI.

Q. How does National Grid's SAIFI performance compare with other NY State utility performance?

A. As can be seen below in Exhibit No. ___ (Reliability Panel-1R), National Grid's reliability performance is consistent with that of other NYS utilities.[4] Except in 2002 and 2003, where there is some deviation that is most likely caused by several large storms, National Grid is trending almost exactly with the State average.

SAIFI data for 2006 are provided only for National Grid. The data from the other utilities will not be filed until March 31, 2007 and therefore are not included in this analysis. The State average is provided without including Consolidated Edison Company ("ConEd"). This is done because ConEd is composed of a mostly networked urban downtown area and their SAIFI is usually very small, thus the data are not reasonably comparable with other utilities in the state that do not have such an extensive downtown, underground, urban network.

An update including SAIFI and CAIDI state wide data for 2006 is included as Exhibit No. ___ (Reliability Panel-1S)

Q. How does National Grid's CAIDI performance compare with other NY State utilities?

A. As can be seen in Exhibit No. ___ (Reliability Panel-1R) below, National Grid's performance is almost exactly following the trend of the State average utility performance. While the trend is above the other utilities in the state, it has not

4 Based on information obtained from the NY PSC web site.

materially changed over the period. As shown in Exhibit No. ___ (Reliability Panel-1R), the upward deviation experienced by National Grid in 2005 was also experienced by customers served by other utilities in the State.

As with the SAIFI information, a 2006 result is available only for National Grid. The state average is provided without including ConEd, because of the very different characteristics of their operating territory.

Q. Please describe reliability performance trends across the nation.

A. (Reliability Panel-1R) below shows trend performance from an Institute of Electronic and Electrical Engineers ("IEEE") benchmark effort[5] that was conducted across North America. The IEEE is a national standards-making body.

In the 2005 benchmark effort, ninety-four companies provided raw data that were then analyzed by the IEEE Working Group on Distribution Reliability using the IEEE Std. 1366-2003 as the basis for the analysis, as opposed to individual State based criteria. Specifically, the group applied the same criteria (IEEE) across all data sets. Analyzing the data using the same methodology for all companies allows for more accurate comparison of results.

Fifty-eight of the ninety-four companies provided consistent data from 2000-2005. "Large" utilities, as defined in Exhibit No. ___ (Reliability Panel-

5 "Distribution Reliability Benchmarking based on IEEE Std. 1366-2003 – 2005 Survey Results", Accepted by the IEEE Transactions on Power Delivery for publication in 2007 and presentation in Tampa, Fl in June 2007.

1R), are those that serve one million customers or more like National Grid's NY territory; there were twenty-four of those companies in the benchmark effort. Those twenty-four companies served over 51 million customers in 2000 and over 54 million customers in 2005. The results from those companies were used to develop the trend charts shown in Exhibit No. ___ (Reliability Panel-1R).

As can be seen, the trend for reliability performance is worsening over time across the whole benchmark group. There has been considerable discussion about the phenomenon at the IEEE group with no definitive conclusions drawn. Members have suggested that changes in weather patterns, addition or modification of outage management systems, and other factors are likely to be contributing to the changes.

Q. How does National Grid's reliability performance compare to other utilities in the nation?

A. Using the information presented in (Reliability Panel-1R), National Grid's performance has been overlaid onto the national performance as shown in (SAIFI performance) Exhibit No. ___ (Reliability Panel-1R) and (CAIDI performance) Exhibit No. ___ (Reliability Panel-1R) below.

In Exhibit No. ___ (Reliability Panel-1R), with the Company's 2006 results included, it can be seen that the National Grid SAIFI oscillates but is a flat trend overall, while the comparison group of utilities has experienced a modest

deteriorating trend over a similar time period, showing that National Grid is performing better than the industry group.

In Exhibit No. ___ (Reliability Panel-1R), with the Company's 2006 results included, it can be seen that the National Grid CAIDI performance is almost exactly the same as the national average.

Q. What is the Reliability Enhancement Plan as referenced by Witness Reulet (p. 17)?

A. As we noted at the introduction of our testimony, the Company assembled a number of teams in 2004 to develop a program to bring service reliability to a more desired level. One of the products of that effort was the Reliability Enhancement Plan, a five-year program composed of both capital and maintenance spending initiatives. The key elements of the plan include: (i) a targeted program to enhance the worst performing feeders (Feeder Hardening); (ii) an enhanced vegetation management program; (iii) increased asset replacements; and (iv) increased maintenance and inspection.

Because the electric system is dynamic, the plans are also dynamic. The specific feeders and areas where work will be performed for fiscal year ending March 2008 (hereinafter "FY08") have been determined and detailed designs have been created. The potential work for FY09 has been identified and is being researched to ensure it will provide the greatest potential improvement for the

cost. At the end of FY08, the final selected projects will be sent to engineering and design for processing, and then on to operations for completion of the work in FY09. For FY10 and FY11, the broad categories of work are in place as budget place-holders. In FY09, the FY10 work list will be generated.

Q. What are the major underlying causes adversely impacting reliability performance that drove the creation of the REP?

A. Lightning, deteriorating distribution equipment, and tree contacts, in addition to changes in weather patterns and more accurate data collection due to an on-going initiative to implement a new outage management system ("OMS") were the main underlying causes of the change in performance as described previously in this testimony. Exhibit No. ___ (Reliability Panel-1R) shows the performance based on customer minutes interrupted, which is the product of customers interrupted and duration. In Exhibit No. ___ (Reliability Panel-1R), the upward, negative trend for trees, subtransmission, and deteriorated distribution equipment is clear. Lightning has also played a role in the deteriorated equipment interruptions in 2004 and 2005. It can also be seen that transmission (115 kV and above) interruptions were not significant contributors to the negative, upward trend in customer minutes interrupted. Based upon this information, the major programs for the REP were developed. Within the REP, work is evaluated on a dollars per change in customer minute interrupted ("$/Δ CMI").

Q. What is Feeder Hardening as referenced by Witness Reulet at p. 13 line 11 and how is it expected to affect reliability performance?

A. A subset of the REP, the Feeder Hardening Program assesses five year feeder reliability performance, with regard to deteriorated overhead equipment and lightning-caused interruptions, to select those feeders that can be improved through overhead maintenance activities and/or asset replacement. All feeders are ranked on: (i) the number of customers served; (ii) customer minutes interrupted per event; (iii) events per mile; and (iv) a dollars per change in reliability improvement metric allowing the Company to produce the greatest improvement in its reliability performance in the most efficient manner.

In FY07 (April 1, 2006 – March 31, 2007), the Company is hardening close to 600 miles of distribution line. In FY08 the Company plans to complete an additional 1,000 miles. The Feeder Hardening work plan is shown below in. As shown in (Reliability Panel-1R), work is planned across the state.

Q. In addition to the Feeder Hardening Plan, what other activity is the Company undertaking to improve reliability performance?

A. As a part of the REP, the Company also added 98 reclosers on its distribution feeders in FY07 and plans to add another approximately 100 in FY08. A focus has been placed on fusing side taps to improve reliability by further segmenting the circuits and reducing the number of affected customers during outages. This

work is intended to significantly improve overall customer reliability performance.

In addition to Feeder Hardening, the Company is also reviewing the PSC worst performing feeder list using an Engineering Reliability Review ("ERR") process. ERR reviews are evaluated strictly on the internal performance of the feeder itself. Major storms and supply issues are omitted from the study. The goal is to recommend projects that will reduce the number of faults, reduce customer minutes interrupted ("CMI") and/or improve the voltage performance of the feeder. The engineers typically recommend projects such as the installation of reclosers, the addition of side tap fusing, addition of capacitor banks and/or regulators to improve voltage performance and major projects, such as reconductoring or conversion to a different voltage. Major projects for FY08 include the creation of feeder ties, some with automatic loop schemes, and reconductoring from bare wire to tree wire or spacer cable.

Q. **What is the distribution asset replacement program and how is it expected to affect reliability performance?**

A. As with all utility companies, the Company's assets are deteriorating as they age. Aging alone does not necessitate replacement. In some cases, however, where it is inefficient or ineffective to provide a complete maintenance program, age is the primary indicator that replacement may be required. The Company has and is

continuing to develop asset-based programs to address specific asset classes to optimize the timing of asset replacement programs based on actual equipment condition and performance.

For example, distribution poles are evaluated and considered for replacement based on the following criteria: (i) age of the pole; (ii) type of equipment on the pole; (iii) proximity to the public; (iv) proximity to wetlands; (v) class of the pole; and (vi) condition of the pole. Other asset replacement programs include, but are not limited to: (i) cutouts; (ii) cable; (iii) substation breakers; (iv) transformers, and (v) conductor.

Asset replacement is intended to improve system performance over time.

Q. **What is an enhanced vegetation management program and how is it expected to affect reliability performance?**

A. The Company has trimmed trees on a cyclical basis since 1979. Starting in 1998, the Company changed its approach to vegetation management by extending the cycle time from five years to an average six year cycle. Some of the savings from this cycle extension were used to start up a new program know as the Tree Outage Reduction Operation or TORO. The program was implemented to remove trees that had a high probability of falling into the power lines, thereby interrupting customers. Based on analysis since the inception of the program, the Company believes that it needs to return to the five year trim cycle and that it must

incorporate the TORO program into this cycle program. To do that, the Company has allocated additional funding to accelerate the program such that by FY12 all circuits will have been trimmed within 5 years.

As I noted earlier, the Company has also refocused its efforts to sub-transmission right-of-way (ROW) widening, and plans to spend approximately $7.5 million between FY07-FY11 to accomplish this task.

Q. Can you please describe the inspection and maintenance ("I&M") program at National Grid?

A. The National Grid I&M program is a comprehensive program that requires inspectors to review 20% of National Grid facilities each year (a five year program) and to record every discrepancy that is found in the field, including those items that are not imminent failure risks or safety only items. In accordance with the Commission's Safety Orders in Case No. 04-M-0159, the Company's I&M program has been augmented for FY08 to have inspectors not only identify condition data but also to identify any deviation from existing internal construction standards.[6] For example, the Company requires arresters to be placed at the end of lines to protect for lightning. Inspectors now actively record where these items are missing. The inspection information directly links to our

6 Case 04-M-0159, Proceeding on Motion of the Commission to Examine the Safety of Electric Transmission and Distribution Systems, "Order Instituting Safety Standards" (January 5, 2005); "Order on Petitions for Rehearing and Waiver" (July 21, 2005) (the "Safety Orders").

asset replacement and reliability improvement processes and assists designers in developing comprehensive construction packages.

Q. What are the priority codes used within the I&M program (in the Computapole database)?

A. As described in DPS 281, defects found during the field inspections are prioritized in the Company's Computapole database in accordance with the following definitions: (i) A Priority - an identified facility/component or tree condition that must be repaired / replaced as soon as practicable; (ii) B Priority – an identified facility/component condition that shall be considered for repair/replacement as the feeder is scheduled for maintenance by Distribution Planning and Engineering. These identified conditions will be corrected as preventive maintenance and or facility life extension; (iii) C Priority – an identified facility/component condition that is being trended and reviewed by Distribution Planning and Engineering that may require replacement through the engineering process. Non-capital conditions identified under this priority will be corrected at the discretion of field operations; (iv) E Priority – an identified facility / component that must be replaced / repaired immediately to address public safety or system reliability; (v) F Priority – an identified forestry condition that should be scheduled as time permits, within the routine right-of-way maintenance and danger tree removal schedules. A

description of these codes has previously been provided to the Dept. of Public Service Staff in accordance with the Commission's Safety Orders.

Priority B and C are not necessarily potential reliability problems. The items that are identified as "B" maintenance items are those that shall be considered for repair/replacement as the feeder is scheduled for maintenance. These items do not require immediate attention and can be prioritized for remediation work. B maintenance items have been collected for numerous reasons including: (i) the existing infrastructure was built to the standards that existed at the time it was installed. As National Grid has evolved, so have the Company's and the Industry's standards, and therefore, during the inspection process items are identified that do not meet current standards. This does not mean that they are unsafe, less reliable, or require immediate attention or that these items are out of compliance with applicable standards (since the original construction standards may continue to apply). Over time these items will be addressed in a planned manner; (ii) the items have a possible safety impact with a very low probability of occurrence, but will have little impact on reliability; (iii) the items are not either safety or reliability related such as pole stenciling; or (iv) the items are good candidates for replacement sometime within the next five years, but, there is a need to review the inspectors' findings and to prioritize and schedule the work.

The items identified as "C" are those facility/component conditions that are being trended and reviewed by engineering that may require replacement through the engineering process over time. C maintenance items do not require immediate attention, but are noted so changes in performance can be tracked during the next inspection cycle. These items provide a broader view of asset condition to the Company and do not represent items that are likely to fail within the inspection cycle period. Only priorities A and E have short-term (within a year) impacts to reliability. The B items may or may not have a reliability impact. The C items are not short-term reliability-related but items for longer-term trending of an asset's condition. If an inspector feels that a specific maintenance item needs immediate attention, they are required to move the priority from B or C up to A or E. The Priority A items must be completed by November 30th of the year in which the item was found so long as it was found prior to November 1st. The Priority E items must be resolved immediately.

Q. **Please discuss the testimony of Mr. Reulet with regard to the category B and C priority maintenance.**

A. Mr. Reulet expresses concern over the effects on the Company's reliability due to the backlog of items categorized as Priority B or C. In particular, he notes that National Grid does not have any specific timeline to address all category B and C items. His concern is that these items become a reliability problem over time if

not addressed by the Company and, thus, should be addressed under a specified timeline.

Q. What is your opinion of Mr. Reulet's position on these priority B and C issues?

A. The company differs with his opinion that all category B and C items require a specified timeline for remediation. Each time these items are inspected, a new assessment of priority is performed, so items that may have been B or C, will be re-assigned a higher priority as necessary. In addition, certain of these items are being addressed in the context of other programs, such as the Feeder Hardening Program under the REP. Mr. Reulet correctly points out that B and C items are not immediate concerns for reliability but are indications that some conditions may need to be addressed during the next inspection cycle for category B items, and monitored over a longer period for category C items. The Company has category A and E for equipment that requires immediate attention. These must be fixed first. Items in category B and C, by definition do not require a set timeline to remediation.

Categories B and C provide the Company with a view to the condition of its assets and possible problems in the future. As such, they are effective tracking devices for the Company in plotting potential reliability issues. Since items in category B and C do not create an immediate risk to reliability and safety,

flexibility is necessary in handling the issues raised by equipment placed in category B and C. Mr. Reulet does state that the Company's Reliability Enhancement Program will work through some of the backlog of category B and, possibly, category C items. The REP will give National Grid the opportunity to clear some of the backlog for those items that have a greater impact on potential reliability problems in the future. However, the REP will select projects that have the greatest value for customers in terms of reliability impact first. As such category B and C items may remain if they are not causing problems in service.

Q **Why is there an apparent backlog in maintenance for overhead lines in Transmission (115kV and above)?**

A Table DW-1 Exhibit No. ___ (Reliability Panel-1R) shows a snapshot of transmission overhead line defects as percentages of the total transmission A, B, C, E and F priorities as listed in Computapole on March 1, 2007. As can be seen, only 2% of the defects are outstanding E priority and A priorities. The current percentages of B priority defects for transmission are listed by category in Table DW-2 Exhibit No. ___ (Reliability Panel-1R).

National Grid's experience has shown that for transmission wood poles (19%) and foundations (1%), it is not cost effective for customers to replace assets on visual inspections alone, as visual inspections are not necessarily an accurate indicator of an imminent reliability risk. National Grid therefore relies on

alternative condition assessment techniques in determining which assets are to be replaced. For foundations, National Grid has a separate on-going program to inspect and repair all foundations on a 20 year cycle. Additionally, National Grid has an instituted program to paint its steel structures on a 15 to 20 year cycle. These alternative strategies for foundation work and tower painting are intended to avoid earlier than necessary expenditures in replacing equipment for our customers, and are hence more efficient.

There are also a number of B transmission maintenance items that do not impact reliability. Two such categories ~~above~~, which make up 66% ~~61%~~ of B defects, include "Non-reliability" and "Insulators." The defects in the non-reliability category are issues that do not directly impact reliability such as missing signage. In addition, many of the transmission B maintenance insulator defects are insulators being out of plumb or one or two insulators missing or broken. A string of insulators may be made up of 8 or 9 insulators; although it would show up as a defect if only one insulator is broken or missing, it does not present a reliability risk and may not warrant immediate attention.

Vegetation related defects listed above (4%) are also handled outside of B maintenance work; we have a comprehensive transmission vegetation management program on which we currently spend $3.6 million annually.

The remaining B priority transmission defects (10% ~~12%~~), which could impact

reliability and are not resolved through other maintenance programs, are resolved within our annual B maintenance program or capital investment programs.

Q. Staff Witness Reulet (p. 13) says the following, "[h]owever, the timing of this program, in light of the merger petition, raises questions about National Grid's true commitment to this subject." Would you care to comment on the timing of this program and whether it is in any way connected to the timing of the merger?

A. Staff Witness Reulet's statement suggesting that the REP was timed to respond to the merger is based on a misinterpretation of the facts. REP development began in 2004, long before the proposed merger, and thus any implication that the REP was timed to coincide with the merger petition is entirely incorrect.

Q. Staff asserts that the Company appears to have reduced its commitment to the REP from $1B to $750M in the span of a few weeks in September of 2006. Is this accurate?

A. No, there was a misunderstanding of DPS-12 and other statements made by the Company. The Company has committed to undertake the Reliability Enhancement Program described above. The response to Request# DPS-12 question 1(b) states, "[i]n fact, National Grid is committed to investing $750 million in their new electric reliability enhancement program over the next five years. $360 million will be invested in the existing NY electric infrastructure on

reliability programs." The $750 million referred to in DPS-12 is to be spent across all of National Grid's US territory in NY, MA, NH and RI. $360 million is specifically targeted to NY distribution reliability over the next five years to accomplish the distribution REP described above. As noted earlier in this testimony, this commitment adds $360 million to the baseline distribution reliability spending of $260 million yielding a total of $620 million focused on the reliability of distribution infrastructure over a five year period.

A complete summary of the Company's capital and reliability maintenance spending associated with the reliability enhancement program is included in the response to information request DPS-281. The table from that response is summarized and attached in Exhibit No. __ (Reliability Panel-2R). This table shows all components of the Reliability Enhancement Program and the total capital spending for the Niagara Mohawk service territory. The components of reliability spending that were referenced in Mr. Edwards letter (Reulet Exhibit DFR-7) included the total distribution reliability spending of $621 million shown on line 3 plus the transmission capital spending of $576 million shown on line 6. The $360 million of distribution capital spending corresponds to the amount for distribution capital shown on line 1, which together with the $265 million of maintenance expense shown on line 2 provides the total amount of spending on the reliability of the distribution infrastructure. The transmission capital spending

of $576 million over the next five years is also included in that analysis.

We recognize that the presentation of these numbers has created confusion. The problem stems from including both capital and O&M figures in the total spending and including New England and New York together in some cases, and not in others. This confusion will continue as we move forward with the programs, because to track spending we would have to identify specific O&M expenses or capital expenditures as associated with reliability enhancement as distinguished from other functions. To avoid this administrative burden, but still demonstrate our progress in implementing the plan, we are focusing on the total capital spending over the fiscal years ending in March 2007 through March 2011. As shown on the exhibit the total capital spend equals $1,470,000. This figure should be easily verifiable on National Grid's accounts. Thus, in the merger condition that we propose associated with the Reliability Enhancement Program we propose to track total capital spending over the period ending March 2011, and report those expenditures to the Commission. We will also explain any deviations from these levels in the reports to the Commission. In that way, the Commission should be apprised of our progress in the implementation of the Reliability Enhancement Program with an easily verifiable comparison.

Q. Could the level of spending change from the planned number?

A. Yes. The value is drawn from our business plan, and we review that plan

continually. However, in this case, we are committing to maintain at least the level of projected spending over the period to $1.4 billion. Our ability to spend this money will also depend on several factors including the ability to permit the projects and maintain the construction forces necessary to implement the work. The planned spending also depends on the prices and availability of materials. Each of these factors could cause the level or the timing of the spending to change from one year to the next. Nevertheless, our commitment is to implement a sustained investment program of $1.4 billion over the five years of the plan. That is the basis for the condition.

Q. Would you summarize National Grid's structure and processes for asset management across the system?

A. Yes, National Grid implements a focused and proactive approach to asset management across the business. Recognizing that the transmission and distribution functions serve distinctly different purposes, require specialist expertise, and each requires a devoted management focus, the Company has established dedicated Asset Management functions in Transmission and Distribution on each critical function. Distribution, on one hand is made up of many small facilities that distribute power in a radial fashion to many end users. It needs to manage many thousands of similar, small projects each with a relatively small cost (compared to transmission) but higher cost in aggregate.

Transmission on the other hand consists of much larger, more complex, harder to site, higher cost (per item) equipment with "regional impact." The Transmission function must manage a much lower number of higher cost, regionally critical projects. In many cases, different skills and expertise are needed in planning the two systems. Therefore, the Company has established dedicated Asset Management functions in Transmission and Distribution to manage the specific assets and asset types on a portfolio basis. Our approach is a systematic one, where we seek to continually update our understanding of the condition of an asset in a coordinated manner across all our assets. Decisions are made on a risk and criticality basis to maximize the long-term benefit to our customers over the whole lifetime of an asset. This means we not only optimize on asset risk, but we also consider the criticality of the asset to the customer both now and in the future, and optimize our approach to provide the least-cost solution to customers over the whole lifetime of an asset.

Q. How is the Asset Management approach applied at National Grid?

A. This approach is applied through a cyclical process that consists of collecting asset condition data, monitoring network performance, analyzing and developing strategies to address asset conditions and changing power flows, developing a coordinated plan, quantifying resources needed, obtaining approvals as required, and implementing the plan as designed. These programs are combined,

prioritized, put through a rigorous governance process for management approval, and developed into a work plan for execution by our engineering, project management and field forces.

Q. Please explain the time frame over which this current process works.

A. The process itself runs on an annual cycle with a business planning and work plan development process. Within the annual cycle, studies, analyses, project prioritization, and work plan adjustments are constantly undertaken. However, the results of this process may take many years to implement and be realized: in many cases five, ten, or even twenty years. A well thought out and justified transmission project can take three years to go through the stages of conceptual analysis, permitting and licensing to final implementation. Many larger projects on transmission can take ten years or more to go through their project development lives. To be cost efficient, asset condition data are typically collected over several years. For example, some of our line inspections are done on a five year cycle; if we need to find specific information for the entire system, it might take this period to collect all the information we need. Another example is forestry: in transmission we have been cycling our tree trimming and vegetation management programs on a 6-8 year cycle based on the height of the conductors and the distance from the cleared edge of the right-of-way. This cycle differs from the distribution cycle mentioned previously in this testimony. The

transmission cycle is consistent with the Commission's June 20, 2005 Order in Case 04-E-0822.[7] Hence it could take a number of years for a change in vegetation management approach to be fully implemented on the system. Of course, where we identify an immediate need for investment, a project receives top priority and moves ahead in the cycle.

It is also worth noting the condition of an asset tends to change slowly over many years, although there may be a point when the condition starts to deteriorate very quickly. Performance of an asset can change for a number of reasons including changes in the environment it is subjected to, its use over a long period of time, and how it has been maintained. While performance can change rapidly due to some of these factors (and will be addressed on a priority basis if it does), it is more likely that performance degrades slowly with the exact timing of ultimate failure unknown. Therefore the condition and performance of many of the assets on the system today are a result of practices and decisions made over the past twenty years or more. The same holds true for increasing performance. The performance of a given piece of equipment can be changed in a step fashion; however, an increase in the overall performance of the system can not always be turned around quickly and usually evolves with the regular cycle of data

7 Case 04-E-0822, In the Matter of Staff's Investigation into New York State's Electric Utility Transmission Right-of-Way Management Practices, filed in Case 27605, "Order Requiring Enhanced Transmission Right-of-Way Management Practices by Electric Utilities" (June 20, 2005).

collection, engineering, permitting, obtaining access to the system to take lines out of service, and construction phased over many years given the size of the system. Understanding this, one can see that the decisions being made today or even over the past five years, can only be expected to move performance in the right direction and the results might not be able to be seen for a number of years. This is a key element of Asset Management: that the assets that make up the power system are long-lived and decisions typically take some time to yield performance results.

Q. How does National Grid leverage its Asset Management expertise for its customers in New York?

A. National Grid benefits its customers in New York by leveraging its world wide knowledge and experience by sharing and deploying best practices across its businesses and functions. This best practice sharing leads to a diversity of ideas and the identification of common practices from which we can benefit. An example of this best practice sharing is Aerial Laser Survey. This technology has recently been deployed in the US and we are currently surveying the entire 115kV and above New York transmission system. Through best practice sharing National Grid has committed to continually improve its decision-making and mature its Asset Management system so decisions are made on a risk and criticality basis with the long-term consideration over the life of assets. This

approach is designed to deliver the least cost solution for customers to achieve maximum reliability over the whole lifetime of the assets.

Q. Can you give examples of other activities National Grid has undertaken since the merger to improve its management of its assets and thereby provide customer reliability benefits?

A. Directly related to active management of the assets, in 2005 we implemented an Asset Information and Maintenance Management System (AIMMS). This system provides us with the ability to manage planned and unplanned maintenance work on equipment in substations, on relay and telecommunications equipment, and in the HVDC installations. The system keeps track of the maintenance and number of operations of the substation equipment and automatically generates work requests based on maintenance needs calculated daily. The system has significantly enhanced and enabled us to prioritize our substation maintenance practices.

We have also modified our long established ComputaPole application, which is the overhead line inspection system. This system has been improved by, among other upgrades, the use of hand-held devices used by field inspectors to input field data directly into the application reducing the need to key in information later, a process that is inefficient and prone to mistakes in the transfer of data.

Q. What is the benefit to customers from this best practice approach?

A. The benefit to customers is value for money. The aim of this asset management approach is to manage our assets to deliver safe and adequate electric service at the lowest reasonable cost. This is often an area of reasonable engineering and business judgment on the part of decision makers. This is quite different from providing the highest reliability at any cost or the lowest possible cost with poor reliability; it is striking the balance that meets both objectives. The process needs to be applied consistently over the typical lifetime of our assets to achieve long-term customer benefits. Other benefits to customers include increased robustness in the transmission and distribution system to better withstand extreme events (such as storms).

Q. What capital and maintenance investments have National Grid made in the system since the merger?

A. National Grid has funded a program of investment in, and maintenance of, the Niagara Mohawk T&D infrastructure from the beginning of the merger. Exhibit __ (~~Reliability~~ Rates Panel-4R) of ~~Mr. Laflamme's and~~ Mr. Molloy's testimony shows that National Grid's annual O&M and capital expenditures increased significantly from 2001 to 2006 and its total expenditures in 2006 were $138 million higher than those in 2001 after adjusting for inflation. These numbers include the transmission and distribution investments for both maintenance and capital

investment. These increases in capital and O&M expenditures demonstrate a strong commitment to increasing reliability for National Grid's customers.

Q. Will the performance of the National Grid transmission system as measured by reliability indices (CAIDI and SAIFI) improve as a result of these expenditures?

A. As can be seen from earlier testimony, we are committed to a systematic approach to the management of our assets and improving their long-term performance as measured through these indices. Our objective has been to put in place a portfolio of asset programs which we are now implementing to progressively improve the condition and reliability of our assets in an efficient manner for our customers. Our efforts encompass all different asset types of capital replacement, for example pole and tower replacements, circuit breakers, transformers, spares, lightning performance, etc., and maintenance policies such as tower painting. We are also working to improve our inspection / condition assessment techniques and frequencies. While each targets a specific system need, they all have a different time period over which they will be effective.

As discussed previously, building and maintaining transmission is complex and the full results may not be evident in a short period of time. As an example, if we were to refurbish our top 10 worst performing transmission lines to make them perform comparably to our best performing lines, the cost would be

on the order of $400 million and would decrease the overall transmission system SAIFI by no more than 2.3% and have a negligible affect on CAIDI. This again demonstrates the significant lead time and resources necessary to make even a nominal difference to the improvement of our reliability statistics given the current asset age and condition.

Q. What transmission expenditures are National Grid planning to make that will improve reliability?

A. As shown in Exhibit No. __ (Reliability Panel-2R), we are forecasting to spend approximately $576 million to improve reliability, maintain asset health, accommodate load growth and load shift, and meet regulatory requirements. This level of spending shows we are committed to improving the performance of the system. It is also worth noting that in our capital spending plan provided to the PSC in 2005 we provided a 5-year forecast on transmission. Notwithstanding the comments of Witness Reulet (p. 13) suggesting that efforts to improve reliability are a response to the merger petition, our current spending forecast and the 2005 5-year forecast referenced above show that our capital spending plans have and are continuing to develop over time and are not just a short-term response to the merger filing. Based on our understanding of current and future needs, we believe that this level of spending is required to carry out the work necessary to have a transmission system capable of meeting the needs of consumers. It should also be

noted that, while we intend to spend overall at this level, the actual annual expenditures are periodically updated and might shift based on the latest available data and as a result of other factors such as availability of permits and outages to carry out the underlying work.

Q. What projects do you foresee will be included in future capital expenditure?

A. The future expenditure includes a number of incremental projects and programs developed over the last 5 years that will impact reliability. It includes programmatic replacements of facilities such as steel towers, wood poles, relays, switches, and breakers; it also includes specific major incremental projects such as work to ensure reliability of the 115 kV system following the retirement at the Huntley station, a substantial refurbishment of our two Porter-Rotterdam 230 kV lines (Porter-Rotterdam 30 & 31), and the asset replacement of the Clay 345kV station.

Q. Witnesses Leuthauser and McAfee, can you please provide further discussion regarding Exhibit No. __ (Reliability Panel-3R)?

A. This exhibit presents a tabular comparison of the staffing levels of line workers between 1999 and 2006. It also corrects and updates Reulet Exhibit DFR-3. The internal employees are reflected as a snap-shot of employee count at each calendar year-end, while the contractor count is based upon the average for the year.

Q. In response to Staff Witness Reulet's testimony that the Company fails to

have ample staff to respond to trouble, can you provide a comparison between the staffing for electric operations pre-merger versus today?

A. Yes. As shown in Exhibit No. __ (Reliability Panel-3R), the Company has not made significant cuts to its internal line workforce, i.e., 683 internal plus 0 contractors in 1999, to 663 internal plus 116 contractors in 2006. In fact, the Company has demonstrated its commitment to fill positions once they become vacant, by filling the majority of "Total Line Worker Terminations or Retirement" illustrated at the bottom of the exhibit. This has allowed the Company to maintain adequate levels by continually filling vacancies as well as complementing the workforce with contractor crews for targeted projects. The exhibit highlights that with the addition of contractor crews, the Company has effectively increased its workforce. In our agreement with Local 97, we have agreed to use more internal line mechanics in the future.

Q. What is a "Qualified" lineworker?

A. A "Qualified" lineworker has progressed to a level "C" or higher through on-the-job training and class room training, while levels "A" or "B" or "helper" are considered "Unqualified" lineworkers. The process of progressing from an entry level lineworker to a C lineworker takes about three and a half years. After an additional two years of experience and training, a C lineworker receives the hotstick rating. Contractor crews and other utilities follow a similar progression. Certain tasks require a one-person Qualified crew, while other tasks require a two-

person Qualified crew. As such an Unqualified lineworker is essentially an extra worker in a crew, permitting the crew to do more work in a given period of time. An Unqualified lineworker cannot serve as a substitute for a Qualified lineworker. However, the Company can supplement its complement of Qualified lineworkers with Qualified contractors. While our percentage of Qualified lineworkers is lower than historical levels, our number of Qualified contractors to offset this is considerably higher.

Q. **Witness Reulet suggests that using contractors may not be effective and specifically, at page 10 line 2 states, "[a]dditionally, the number of available contractors can vary and hiring additional contractors can be delayed as a result of the bidding process." Do you agree with these assertions?**

A. No. To the contrary, the contractor workforce provides select flexibility that is not offered by internal crews. Specifically, contractor crews can be sited in any geographic location and can be increased or decreased more readily. The Company has in place pre-negotiated agreements, referred to as "alliance contracts," which eliminate any delay that might result from continual re-bidding of contracts. Indeed, the time requirement for retaining a Qualified contractor (i.e., the "bidding process") is much quicker than the time it takes to qualify a lineworker. Furthermore, contractors tend to encourage the internal Company employees to remain competitive with respect to cost and productivity. The

Company has found through experience that utilizing a combination of both internal workers and contractors offers the greatest flexibility and ability to efficiently complete the work.

Q. **Has the Company made changes to enhance the productivity and coverage of its internal workforce?**

A. Yes. The Company has effectively made strategic changes to its workforce complement, including the addition of a new job classification of One Person Line/Trouble Mechanic Crews (OPCs). These OPCs have helped support and maintain outage & trouble response by increasing the availability of crews in the 24 hour day period. Essentially, the addition of the approximate 44 OPCs in New York has increased the coverage for emergency response. In addition the Company has added shifts increasing the use of flexible schedules to cover more hours.

Q. **How can you assure the contractor will continue to work for National Grid when contractors are called upon to assist others during trouble or weather events?**

A. The contract terms for these services are designed to bind the contractor to the Company, specifically, with the following provision:

"Emergency Assistance

60.1. If the Contractor is notified and requested to provide emergency assistance, by a company other than the Owner [National Grid], the Contractor shall request a

temporary release from the Agreement. It will be the Owner's decision as to whether this request will be granted. If the Owner agrees to temporarily authorize the release of the Contractor from its current obligations, both parties shall sign a Temporary Release Document. This Document will state for whom the Contractor will be working, the anticipated release period, that the Owner will not incur any costs or legal implications due to the Contractor's release and that the release will cause no significant delay in the completion of the Owner's Project."

Q. What are the Company's plans for future hiring for the line workforce?

A. The Company's current plan over the next three years is to add approximately 70 to 80 line worker positions to the New York service territory. The Company also anticipates that it will need to replace approximately 20 to 30 positions due to anticipated retirements over the same period of time. Overall the Company expects the resulting line worker total in New York to be in the range of 730 to 750. While this is the Company's goal, the projection must be considered approximate, given the difficulty in predicting the number of retirements that will actually take place. We have increased this commitment in our recent agreement with Local 97. The Company and Local 97 agreed to finalize the details of a memorandum that allows union workers to move voluntarily to transmission work and be backfilled one-for-one in distribution. In addition, the agreement provides that: "The Company intends to maintain a staffing level of 700 positions in the Distribution Line Department located in upstate New York, and seek to add at least 30 positions annually over each of the next three years."

The Company feels that at any one time 10 to 20 percent of these workers would be in a progression cycle. This would be an acceptable percentage and would allow the Company to stabilize its workforce attrition over the long-term. The plan is further supported and complemented by the Company's current contracting strategy as discussed earlier in this testimony.

While the Company's plan entails replacing retiring employees, it is extremely challenging to accurately estimate how many employees may choose to

retire at any given point in time. The retirement attrition process is further complicated by recent federal changes to pension reform. These changes have created an uncertainty which has caused employees to retire sooner than they may have otherwise. The Company could not have predicted the passage of new laws or their impact on the Company's workforce. Facing this uncertain attrition, the Company is establishing alliances with local community colleges to establish programs for lineworker training and education. Until such programs mature and retirements stabilize, the Company will continue to rely on the competitive market of Qualified contractors to address this volatility in workforce needs. The Company manages the staffing process to maintain a Qualified workforce presence. The Company recognizes that the percentage of its Qualified workers has been higher in prior years and as a result it needs to supplement its newer workforce with Qualified contractors while these new line mechanics complete the progression and training process.

Q. Do you believe that the integration team's staffing recommendations will adversely affect reliability in upstate New York?

A. No. The integration team's recommendations do not affect lineworker staffing. Estimated FTE reductions are focused on streamlining and consolidating back office, clerical and dispatch operations. In addition, the team has made a number of recommendations related to technology upgrades and adoption of best practices

intended to lead to better service.

Q. Can you elaborate on the Company's ability to respond to weather storm events?

A. The merger of National Grid and Niagara Mohawk expanded the pool of internal labor that is available for response to weather events. Although the number of internal T&D employees in New York is down slightly, the larger company provides a much greater number of internal crews that can respond to trouble and weather events. For example, in the recent storms in Buffalo beginning October 12, 2006, the Company utilized 154 FTEs (73 crews) from our New England operations. Again, in the ice storm beginning January 15, 2007, that plagued the state, especially in our Eastern New York Division, the Company utilized 51 FTEs (22 crews) from our New England operations. In addition, while Exhibit No. __ (Reliability Panel-3R) only shows contract resources in New York, the pool of contractors available during major weather events would include contractors on the Company's property both in New York and New England.

Pre-merger, mutual aid from National Grid - New England to assist customers in New York may not have been a priority. As a result of the merger, affiliated companies can be asked to prepare in advance of a storm, thus minimizing delays in crew movement as well as ensuring support that can now be planned and deployed strategically. With the addition of Keyspan, this will be

further enhanced by their workforce. In fact, with the most recent weather storms in Buffalo and Eastern Division, Keyspan/LIPA crews were used.

The Company utilizes consistent work practices, standards and operating procedures across our system. For example, with common clearance and control policies across the system we do not need to provide local line supervision to ensure that safe and proper tagging is taking place, as these crews are already trained in these work practices. The supervisor resources can now be used to support areas of restoration that have a more significant impact to shortening the restoration effort.

Q Does the contractor work schedule preclude them from being available Fridays or weekends as suggested by Witness Reulet at page 9, line 28?

A. In the event that a storm is predicted to hit on a particular weekend, the Company has the ability to hold contractor crews that would otherwise be completing their planned work for the week and has implemented this practice for all recent storms. Regardless of where the contractor lives, they can be retained to work on National Grid property.

Q. Witness Reulet at page 7 line 10 – 27 comments on the Company's performance in the aftermath of the February 17, 2006 windstorm. Can you comment on the Company's performance in major storms that followed the February 2006 windstorm.

A. Yes. Following the February 2006 Storm, the Company has adopted additional processes to respond to storms. In the more recent storms in Buffalo in October 2006, where approximately 262,800 customers were without power and recently in the Eastern Division starting on January 15, 2007, where approximately 85,000 customers were without power, the Company faced severe system damage and a large number of outages. The Company utilized an increased number of crews from many sources (internal, mutual aid and contractors). Specifically over 800 line crews were used in Buffalo and over 400 in the Eastern Division storm. The Company established centralized staging areas to manage and assign work to the crews. The Company has also reached further into the organization to provide support for field operations. In addition, the Company has enhanced its communication process with local governmental authorities (i.e., local mayors, town supervisors, etc.) by hosting daily conference calls with them. The Company has also used its website to post information on outages and restoration efforts. The Company has placed its communication trailer at readily accessible sites for local leaders to come and communicate with our Business Service personnel to exchange information. Increased communication channels have been implemented with positive feedback received.

Q. Has the Company received any recognition for its efforts to improve weather and storm response?

A. Yes. The Company received positive feedback from the media and the local governmental leaders in both of the recent storms in Buffalo and the Eastern Division. In addition, the Company received several awards over recent years for successful response. In particular, the Company won the Emergency Recovery Award for 2006 (presented in January of 2007) for its response to the October snowstorm in Buffalo, New York. Indeed, in a February 27, 2007, article in the Press Republican, Essex County Officials complimented the Company's restoration of power after storms and emergencies as well as the Company's progress in implementing its reliability enhancement plans for customers in the County.

Q. Do you agree with the assertion of Local 97 that reductions in the operating staff will result in a continual degradation in electric service reliability and safety?

A. No. Local 97 and Witness Reulet suggest that the correlation between reductions in internal line workforce and declining reliability performance is equivalent to causation, i.e., that the reductions cause the declining performance. This is not accurate. As discussed by Witness Warren previously, there are many other factors, not unique to National Grid, contributing to declining performance on the reliability indices. Local 97 provides no empirical or other evidence of a causal connection linking internal staffing directly with performance on the reliability

indices. As discussed previously in my testimony, the Company's commitment to line workforce is unabated. Moreover, the Company seeks to maintain a line workforce adequate to improve and maintain service quality and reliability performance, and to add additional line workers, where appropriate.

Q. **Do you have any clarifications that you would like to make regarding Mr. Falleta's testimony pertaining to a December 2006 "Rollins Avenue," Saratoga Springs motor vehicle accident, and in particular regarding the role that concern about "rest time' played in the Company's actions that morning?**

A. Yes. I'd like to provide a more complete description of the event in question. Our records indicate that Witness Falleta is referring to a pole strike on "Rowland Street" rather than "Rollins Avenue." At approximately 0230 on Sunday December 17, 2006, a motor vehicle accident (MVA) occurred at pole 63 on Rowland Street, Saratoga. At approximately 0300, a metering services representative was dispatched to the scene to assess the damage. The employee reported back to Eastern Regional Control that the pole had some damage approximately 4 feet above ground line and felt that it could be assigned to a crew that was scheduled to come in later that day. A crew from Glens Falls that was scheduled to work on that day arrived on site at 1100, evaluated the pole and made a decision not to undertake repairs at that time. No consideration of limiting

overtime hours worked was at play, since this crew continued to work until 1800 that day on other scheduled and emergency work. Later that day a supervisor visited pole 63 on Rowland Street to evaluate the pole and determine whether a work order should be created. Unfortunately, he entered the wrong pole number on the work order, and the work was not completed. While this outcome was regrettable, it was not the result of a conscious management decision not to undertake necessary repairs of damaged facilities. It is also worth noting that, at approximately 0830 on the same day, a second MVA occurred at pole 18, Route 9, Malta. Separate crews from Saratoga were called out to effect repairs at the Malta location. In light of the Company's willingness to dispatch crews to respond to these and other events, the Company was not restricting the dispatch of crews to do necessary work because of "rest time" or any other such concerns.

Q. **Do you have any clarifications that you would like to make regarding Mr. Falleta's testimony pertaining to a January 6, 2007 pole being struck by a vehicle at approximately 11:00 p.m.?**

A. We would like to provide a more complete description of the event in question. We requested information from Local 97, so we could identify the incident in question and provide a more thorough explanation. However, the information was not available in time to research the second incident and prepare a response.

Q. **Has the Company implemented a downsizing program of its line workforce**

as alluded to by Witness Reulet ~~and Local 97~~.

A. No. The Company has experienced volatility in retirements as shown on Exhibit No. __ (Reliability Panel-3R). As discussed previously in our testimony, to combat this, the Company has hired additional employees (both Qualified and Unqualified) into the line department, established alliances with community colleges, and retained additional Qualified contractors. In aggregate, the Company has now effectively increased its line workforce since the merger.

Q. Does this conclude the testimony of the Reliability Panel?

A. Yes it does.