APPENDIX A

David C. Parcell Cost of Capital Testimonies

Year	Utility	Jurisdiction	Case or Docket No.	Client
1998	United Water of Delaware	Delaware	98-98	Staff
2001	Artesian Water Co	Delaware	00-649	Staff
2001	Chesapeake Utilities Corp	Delaware	01-307	Staff
2002	Tidewater Utilities Co	Delaware	02-28	Staff
2002	Artesian Water Co	Delaware	02-109	Staff
2003	Conectiv Power Delivery	Delaware	03-127	Staff
2005	Delmarva Power & Light Co	Delaware	05-304	Staff
2006	Tidewater Utilities	Delaware	06-145	Staff
2006	United Water Delaware	Delaware	06-174	Staff
2007	Delmarva Power & Light --	Delaware	06-284	Staff
2007	Chesapeake Utilities	Delaware	07-186	Staff
2008	Artesian Water	Delaware	08-96	Staff
2009	Artesian Water	Delaware	Regulation No. 51	Staff
2009	Tidewater Utilities	Delaware	09-29	Staff
2009	United Water Delaware	Delaware	09-60	Staff
2011	United Water of Delaware	Delaware	10-421	Staff
2011	Artesian Water	Delaware	11-207	Staff
2012	Delmarva Power & Light	Delaware	11-528	Staff
2013	Delmarva Power & Light (G	Delaware	12-546	Staff
2013	Delmarva Power & Light	Delaware	13-115	OPC

APPENDIX B

delmarva power

A PHI Company

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August 26, 2005

VIA E-MAIL and FIRST CLASS MAIL

Mr. Bruce H. Burcat
Executive Director
Delaware Public Service Commission
861 Silver Lake Boulevard
Cannon Building, Suite 100
Dover, DE 19904

Re: Informal Comments on Draft Proposed Regulations in Regulation Docket No. 50

Dear Mr. Burcat:

Attached are comments that have been prepared with respect to draft proposed regulations that Staff provided to us earlier this month. We certainly appreciate the opportunity to comment prior to the time when proposed regulations are officially published and, in that same spirit, we gladly participated in the workshop process that Staff used to explore these issues over the last several months. This letter is intended to highlight a few issues, including an issue regarding the workshop process itself.

First, I would note that there are a large number of issues that do not appear to be close to a consensus resolution and will require additional proceedings. I do not see any realistic possibility that this can be accomplished before the end of the year when the interim regulations expire. For that reason, Delmarva would suggest that the parties may wish to propose jointly to the Commission that the interim regulations be extended until superseded by whatever regulations are finalized out of this process.

Second, while Delmarva has not yet attempted to quantify the dollar impact of the proposed regulations, it is not difficult to see that the amounts involved could be many millions, even tens of millions of dollars. Requiring the Company to install certain types of equipment and directing that its vegetative management, inspections and maintenance of facilities be done in a particular way not only suggests micro-management, but would impose significant additional costs with no clear benefit. A congestion hours standard that has no cost-benefit criterion could require tens of millions in capital costs in an attempt to meet a standard that may be unobtainable in any event due to the actions of third parties.

Third, and related to the first point, Delmarva would request that the Staff seriously consider the possibility that no additional regulations are necessary and that the interim regulations could be repromulgated as final regulations. In support of that concept, Delmarva would note that its attached comments set forth customer satisfaction statistics, including statistics tied directly to reliability, which show customer satisfaction at relatively high levels and significantly up from 1999. It is certainly not clear to Delmarva that the workshop process identified any particular need suggesting that major changes, or even any changes, are needed to the interim regulations. Alternatively, but along the same lines, Staff may wish to consider the merits of focusing the rest of this proceeding on establishing a reasonable penalty/reward structure around the existing interim standards.

Fourth, with respect to the proposed regulations themselves, Delmarva's single largest issue is going to be the method by which the CAIDI and SAIFI statistics are set. Stripped of verbiage about how the standards were developed, the end proposal is that the standard for each year will be based solely on the prior three-years of actual experience. That means that even a slightly "worse" statistic in year 4 relative to one of the years incorporated into the average may result in a violation of the statistic. E.g., the proposed regulations initially set the SAIFI standard at 1.80, but if the SAIFI results over the next few years were 1.74, 1.70, 1.60, and 1.69, the 1.69 statistic in Year 4 would violate the standard. It would be above the 1.68 average over the prior three years even though: 1) there was no single year that was above the initially set SAIFI standard of 1.80; 2) the 1.69 figure is better than the initially set SAIFI standard and two of the previous three years; and 3) that degree of variability is well within what would be expected given differences in weather, statistical variability in the failure of system components, and so on. Moreover, this structure creates a perverse incentive by enhancing the likelihood of future penalties if there is a particularly good performance in one year -- the 1.60 statistic from Year 3, almost guarantees that the utility will violate the standard in Years 5 and 6. The Company strongly urges Staff to reconsider its proposal and restore the use of a standard deviation band around a statistic. The interim regulations use a one year statistic and a 1.75 standard deviation. The Company has proposed the use of a 5-year average and a 1.75 standard deviation. No matter what the final result may be, however, it has to incorporate a standard deviation band of some reasonable size in order to avoid creating "violations" that are the result of weather and normal statistical variations.

Delmarva will also continue to oppose the imposition of a congestion hours standard. Congestion is simply not a reliability issue – it is a pricing issue. The FERC fact finding investigation speaks to this point as well. Moreover, since congestion is only partially within Delmarva's control, it is inequitable to impose a standard that Delmarva would "violate" whenever other entities take actions in their own self interest that cause an increase in congestion.

Other substantive issues are addressed in the attached comments, some of which will also be noted here in the context of a broader concern regarding the workshop process itself. Unlike the workshop process that led to the recent settlement in Docket No. 04-391, the workshop process here appears not to have moved much toward a consensus. Perhaps this can be seen best in the context of the proposal to create a standard regarding the percentages of customers to be restored within a defined period after a major event. This concept was first floated by a member of Staff during workshops held as part of the Hurricane Isabel proceeding. In that proceeding, the Company repeatedly explained that every major event has unique characteristics and it presented data to Staff to show that other utilities faced with major events have had outages with durations of two weeks or more affecting many customers. For that reason, the Company urged in those Hurricane Isabel workshops that no major event restoration standard be recommended. Notwithstanding the data provided to Staff, Staff continued to push for such standards and it became a litigated issue before the Hearing Examiner. The Hearing Examiner did not recommend and found no reason to pursue Staff's proposal for developing major event restoration standards. While the Commission subsequently directed the parties to continue to look at this issue, there was no directive that some standard was required to be developed irrespective of the outcome of this review. In a workshop that covered this subject, Delmarva, DEC and representatives of the Local Union, spoke against having a major event restoration standard. In addition to the arguments presented in the Hurricane Isabel proceeding, Delmarva and the Union representatives identified a potential safety issue – no one would want to create a regulatory incentive for a utility to reduce in any way its emphasis on safety in order to meet some arbitrary percentage of customers restored in a certain period of time. While there appeared to be a consensus on this point at the workshop, the proposed regulations seemingly ignore this input and consensus to propose major event restoration standards.

While the foregoing is perhaps the clearest example, there are a number of other areas where it is difficult to discern that the workshop process has actually led to a proposal that reflects the views of the workshop participants. I do not believe that any participant other than the member of Staff leading the workshop has supported the intrusion of the Commission into the business practices of the utility in the form of telling a utility how often to do tree trimming and inspect facilities and what kinds of equipment should be installed on the system.

Last, but certainly not least, the Company continues to oppose in this and any other context proposals that are asymmetrical in creating potential penalties with no potential for rewards.

I hope that this letter highlights and clarifies some of the Company's key concerns that are discussed in the attached comments.

Respectfully submitted,

Randall V. Griffin

cc: Connie McDowell
James McC. Geddes
Janis Dillard
Robert Howatt
David Bloom
Arthur Padmore
Bo Shen
Bill Andrew
Cynthia Longobardi
David Rosenstein
Mike Dennis
John Citrolo
John Stutz
Ken Ellers
Kevin Neilson
Wayne Hudders
Paul Simon

DELMARVA POWER & LIGHT COMPANY
COMMENTS ON

STATE OF DELAWARE

DELAWARE PUBLIC SERVICE COMMISSION

Electric Service Reliability and Quality Standards

Staff Report

Version Received August 4, 2005

(August 26, 2005)

Contents

Summary

The process of determining electric service reliability and quality standards for Delaware customers began in 1999, and since that time there have been white papers, workshops, proposals, hearings, recommendations, orders, and interim standards. Throughout this process, Delmarva Power & Light (DPL) has been an active participant, because we believe reliability is a critical issue for our customers, employees, and shareholders. Like Staff, we believe that if reliability service and quality standards are to be established, they must be fair and equitable to the public and utilities. We received the Staff's latest reliability standards proposal on August 4, 2005. We have concluded that the standards proposed are **not** fair and equitable for the following reasons:

1. DPL is already meeting, and has met, the reliability expectations of our customers.
2. Staff has not provided a rationale for why a standard should be implemented.
3. Staff has not reflected many of the positions put forward by DPL during the workshops.
4. Staff has proposed that the Commission micromanage DPL's maintenance and inspection programs by mandating when and how a program is to operate.
5. Staff has recommended implementing technology without regard to the burden the cost of implementing that new technology may place on the public.
6. Staff has proposed implementing standards in areas where DPL has limited authority or control.
7. Staff has not addressed weather and other aspects of variability that are outside DPL's control.
8. Staff has proposed that the Commission be responsible for assessing penalties for violating the standards while being arbitrary with respect to the size, extent. and duration of the penalties
9. Staff has, with no discussion, eliminated the possible of DPL earning a reward for exceeding benchmarks.

DPL proposes, because of the unfair and inequitable nature of the standards, and because in many cases there is limited rationale supporting the creation of the standards, that current interim standards be extend through 2007.

Electric Service Reliability and Quality Standards

(August 4, 2005 Draft)

This section of DPL's commentary addresses specific issues within Staff's August 4, 2005, proposed Electric Service Reliability and Quality Standards. DPL raised these issues at the workshops, but, to a large extent DPL's comments appear to have had little effect on influencing Staff's proposals. However, based on the assumption that Staff wants feedback on the August 4, 2005, version of the proposed regulations, we have commented below on the following areas:

1. Why change?
2. Inconsistencies in Staff's papers over the last six years.
3. Rationale for SAIFI and CAIDI benchmarks
4. Rationale for Constrained Hours of Operation
5. Rationale for Enhanced Maintenance and Inspection requirements
6. Rationale for Establishing Restoration benchmarks
7. Rationale for Notification of and Reporting Major Events
8. Rationale for SCADA expenditures
9. Penalties and Rewards

<u>Why change?</u>
As noted in earlier parts of this commentary, the Commission began this regulatory process as a result of legislation regarding maintenance of levels of reliability. The Staff was asked to explore whether electric service reliability and quality standards are required. Interim standards were established in November 2003. As has been demonstrated in the section DPL Performance, DPL's performance has been maintained since 1999, customers appear to be satisfied with DPL's overall performance, and even more satisfied with DPL's reliability; therefore, DPL questions why the interim standards should not be made permanent.

In the proposed regulations, Staff identified two plausible reasons as to why the standards approved in November 2003 should change: a) to ensure that DPL provides service that is consistent with pre-restructuring service levels and b) to ensure DPL is in compliance with National Electrical Safety Code Standards and transmission operating policies and standards. Staff has never indicated that DPL was not in compliance with all appropriate standards; therefore, we assume b) is not a rationale for changing the interim standards. Similarly, electric service reliability and the customer's perception of that level of reliability is consistent with pre-restructuring levels; therefore, DPL meets the only other test put forward by Staff for proposing new standards.

<u>Inconsistencies in Staff's paper's over the last six years</u>
In the proposed August 4 regulations, Staff puts forward revised reliability standards (e.g. SAIFI) and adds a number of new standards (e.g., Major Event), but in so doing they are inconsistent with earlier positions. For example, in the minutes of the January 19 workshop "... penalties and rewards around the benchmark were an integral part of the

overall effort and would have to be taken into consideration when establishing benchmarks." Yet the August 4 draft establishes standards without any consideration of rewards. In its March 20, 2001, White Paper, Staff states, "How best to achieve compliance with the standards would be left to the discretion of the utility." Yet the August 4 draft establishes SCADA, Equipment, and Vegetation standards. Another example can also be taken from the March 20, 2001, White Paper where Staff states, "The Commission should allow the distribution companies to determine the appropriate level of tree trimming. It should not dictate tree trimming schedules, but should allow Staff's proposals to direct the utilities needs." Yet the August 4 proposal in Section G, paragraph 3) mandates inspection and trimming standards. Staff has not provided any rationale as to why it is proposing to make changes from its original March 20, 2001, recommendations.

Rationale for SAIFI, CAIDI and other reliability benchmarks

Staff has proposed a SAIFI benchmark of 1.8, and a CAIDI benchmark of 134 minutes for DPL is set so low that it virtually guarantees DPL will violate the standards every year that its annual CAIDI is even marginally more than the CAIDI standard. Staff also proposes that DPL report performance against these benchmarks for the current year and on a three-year rolling average. The rationale for the Staff benchmarks seems to be overly complicated to arrive at a simple average for the last three years (2002-2004) of performance. While Staff states that it arrived at these benchmarks by creating an OMS adjustment factor that is a ratio of DPL's five-year (1995-1999) average performance to its most recent three-year (2002-2004) average; the resulting OMS factor is then applied to the historic five-year performance. The resulting SAIFI (1.79) benchmark is no different than if Staff had merely calculated the average of the last three years' performance. While DPL agrees that there needs to be an adjustment factor applied to historic reliability performance for the introduction of a new OMS, Staff needs to provide a rationale for the approach it adopted. DPL also agrees that the benchmark needs to be based on more than one year's performance. Further, using a three-year average does not allow for normal variability in weather and other factors beyond DPL's control. There should be a minimum of five years of post OMS. Therefore, DPL has proposed using a five-year rolling average. As noted earlier, Staff has failed to incorporate any allowance for normal variability. DPL proposes that a band around the five-year rolling average benchmark be established. The band width should be +/- 1.75 standard deviations about the 5-year average.

Staff has based its benchmark determination on DPL's actual performance. DPL agrees with this approach, but as noted, DPL believes there should be five years of actual data (2002-2007). Therefore, DPL proposes that the interim standards be extended through 2007, and at that point a five-year rolling average standard be determined and used starting January 1, 2008.

DPL also wants to correct the definition of $CELID_8$ and $CEMI_8$ put forward by the Staff. $CELID_8$ represents the total number of customers that have experienced a cumulative total of more than 8 hours of outages. $CEMI_8$ is an index that reflects the total number of customers having 9 or more outages. Mathematically, this is given in the following equation[1]:

$$CEMI_8 = \frac{\text{Total number of customers that experienced more than 8 sustained interruptions}}{\text{Total number of customers served}} \quad \frac{500}{300{,}000}$$

Rationale for Constrained hours of Operation benchmarks

Staff proposes establishing a constrained hours of operation benchmark of 600 hours for DPL. DPL strongly opposes any constrained hours standard because:

1. Congestion is a pricing mechanism and not an issue of reliability; and
2. Congestion is only partly controllable by DPL. For example, if NRG closed down Indian River, congestion hours would likely increase significantly. This summer a change in the way PJM dispatches Chesapeake Commonwealth's Virginia unit appears to have affected the level of congestion on the peninsula.

Current provisions relating to congestion merely trigger a study to find a potential cost effective solution. This concept is totally absent from the approach, and proposes one which results in a violation for exceeding the standard. Throughout the workshops, DPL raised jurisdictional, definitional, and practical issues regarding the adoption of any constrained hours of operation standards. The Staff has not addressed these issues. For the reasons stated in the workshops and in prior discussions, DPL continues to believe that there should not be a standard for constrained hours of operation.

Rationale for Enhanced Maintenance and Inspection requirements

Staff introduced equipment and vegetation inspection and maintenance standards. The only rationale provided for these standards was, "Each EDC shall have an inspection and maintenance program designed to maintain delivery facilities' performance at an acceptable level." The Staff-proposed regulations then go on to state, "...The program shall be based on industry codes, national electric industry standards, manufacturer's recommendations, sound engineering judgment and past experience." DPL sees no reason for these standards since DPL has, since its inception, followed the criteria put forward by the Staff for making maintenance and inspection decisions. In addition—and specifically with reference to vegetation management—DPL has already been recognized by the Commission, Staff, and others for its outstanding vegetation management program. The Hurricane Isabel hearings included an extensive review of DPL's reliability-centered approach to vegetation management. Staff appears to have established vegetation management benchmarks with limited reference to DPL's existing practices, and without taking into consideration the potential cost to the public of implementing a two-year inspection and four-year trim cycle. DPL does not believe it is necessary to adopt any maintenance and inspection standards.

Rationale for Establishing Restoration benchmarks

Staff has introduced a number of requirements related to restoration. Staff has proposed that 95% of all customers experiencing a major outage be restored within three days, and

[1] IEEE 1366-2003, page 6.

100% within five days. Staff offers little rationale for why the 95% and 100% benchmarks have been chosen. In the workshops, Staff's presentations recognized that no two major events are the same, and that there is significant variability in weather-related events. Staff appears to have based its rationale for these metrics on an EEI survey which reviewed a number of major events between 1989 and 2003. The study was based on 44 voluntary responses and failed to include, for example, the Hydro Quebec ice storm of 1998, and Hurricane Andrew of 1992—both of which resulted in outage durations of greater than 30 days. The survey also did not take into consideration any of the four hurricanes to hit Florida in 2004. The range of outage duration for these four events was from 8 days to 15 days. DPL does not believe it is possible to establish major event restoration benchmarks, based on all the factors Staff has identified that contribute to no two events being the same. DPL also believes that creating arbitrary benchmarks for rates of restoration does not take into consideration a factor that is of concern to all parties—working safely!

Rationale for Notification of and Reporting Major Events

DPL continues to support the need to report major events to the Commission. As noted in DPL's response to Hurricane Isabel, major events are community events; therefore, the DPL should report to the Commission. Staff has correctly identified that the IEEE 1366 (2003) methodology results in more consistent and mathematically supportable reliability statistics. DPL will continue to use IEEE 1366 (2003) to report reliability statistics. But because the exclusion criteria vary from year to year and it is difficult to determine when the Commission should be notified regarding a major event based on actual performance, DPL will—for **major event reporting** purposes—report to the Commission when there is a sustained outage to more than 10% of DPL's customers during a 24-hour period.

Rationale for SCADA expenditures

Staff has proposed mandating the use of SCADA. Staff has incorporated the following definition into the proposed regulations:

"The SCADA system, at a minimum, shall consist of a remote monitoring and operating ability for all major transmission, substation and distribution circuit components integral to maintaining the reliability of the system. The system will have the ability to:

a. Monitor and record critical system load data and major equipment status;
b. Provide remote operational control over major equipment; and
c. Incorporate generally accepted utility industry safety and security standards."

Applying this requirement to all major substations could cost millions of dollars. Depending as to how one interprets the ambiguous terms (e.g., distribution circuit component), the costs could be multiples of that amount. DPL raised similar concerns over a Staff proposal that was similarly broad and similarly ambiguous in the February 10, 2005, workshop. While the words have changed, the problems of ambiguity and the lack of a cost benefit test remain. Staff still has not addressed whether the additional cost to be incurred provides a commensurate value to the customers. For reasons similar to those already articulated above in the Inconsistencies, and Maintenance and Inspection sections, DPL does not support the adoption of SCADA deployment standards.

Penalties and Rewards

Staff's proposal does not address rewards, and the penalties that could be applied are undefined as to size, when they would be applied, and on what basis the Commission would be able to determine such matters. As noted above and as stated at the January 19, 2005, workshop, establishing standards without knowing the philosophy, rationale, and methodologies for penalties and rewards means that an integral part of determining the standards is not addressed. In addition, not addressing normal variability through the use of upper and lower performance bands means that an integral part of determining standards has not been addressed. DPL continues to propose that if penalties are to be introduced, then equity dictates that DPL must have an opportunity to earn a reward. If penalties and rewards are not to be included, then it must be made clear that Staff is recommending only reporting standards.

Docket 50 History

As noted earlier, the process of establishing reliability standards for electric utilities operating in the State of Delaware began in 1999 with the opening of Docket 99-328 (Order No. 5480). Since then, the Staff has issued and revised a white paper concerning reliability standards, held workshops, and most recently, proposed Standards. The DPSC has issued a number of Orders related to Docket 50 and promulgated interim reliability standards with Order No. 6298 on November 4, 2003.

The March 20, 2001 Staff white paper entitled ***Electric Reliability White Paper,*** and revised and released by Staff on May 1, 2002, primarily addressed generation and transmission capacity and load issues. For example, in Section IV of the white paper entitled **Possible Solutions to Address Reliability Concerns,** the topics discussed included the following: "Increasing Generation Capacity on the Peninsula", "Changing the PJM Rules", "Increasing Transmission Import Capability", and "Load Management". There is very little reference to reliability standards for the distribution system. The white paper contained fifteen recommendations, none of which dealt directly and explicitly with the establishment of distribution system reliability standards (See Appendix I). The only potential reference is incorporated in recommendation #1, but even here the Staff leave it to utility… *"How best to achieve compliance with the standards would be left to the discretion of the utility."* DPL agreed with this statement at the time and continues to agree with it today.

Since there is no reference to specific reliability standards, there is no reference to penalties or rewards associated with the performance of the distribution system. It is interesting to note that on page 26 of the white paper, the Staff stated, *"The Commission may want to consider supporting a proposal by the TOs at the FERC for performance-based ratemaking for transmission enhancements."* And within the same paragraph, it was noted, *"The baseline used in the PBR plan proposed by the TOs should be reviewed to determine its reasonableness. (All available historic data should be incorporated in the development of an appropriate baseline for any performance based ratemaking plan, so that the baseline is not artificially depressed. There is an incentive to reduce performance during a period in which a service provider is knowingly establishing a baseline against which future performance will be measured.)"*. From these statements DPL concludes that the Staff was supporting three critical issues in situations where penalties or incentives are applied. They are:

1. Before implementing any performance mechanism, a baseline has to be developed, based on a sufficient amount of historic data to insure the baseline reflects reality.
2. Both rewards and penalties should be incorporated in any mechanism designed to maintain a certain standard of performance.
3. It is acceptable for a utility to earn an incentive beyond its return on equity, should it perform above a baseline.

DPL agrees with the underlying thinking on which Staff recommendations were made in the white paper.

Also, as noted above, the process of determining an appropriate set on reliability standards continued and culminated in the creation of interim reliability standards in November 2003. In their order, the Commission accepted the recommendation of the Hearing Examiner. In summary, the Hearing Examiner recommended:

1. The establishment of interim reliability standards for DPL that were developed based on DPL's "distinct operating characteristics";
2. That the industry reliability indices System Average Interruption Frequency Index (SAIFI) and Customer Average Interruption Frequency Index (CAIDI) be adopted as the DPSC reliability standards;
3. That there be a band of 1.75 standard deviations for data availability;
4. That the SAIFI target should be 2.3 and the CAIDI target should be 141 minutes;
5. That the SAIFI and CAIDI targets not be used to penalize DPL;
6. That DPL submit annual Planning and Studies and Performance Reports;
7. That IEEE 1366, once adopted by IEEE, be used to determine SAIFI and CAIDI; and that
8. The interim reliability standards should apply through 2005.

The Hearing Examiner made no recommendations concerning Constrained Hours of Operation.

DPL agreed with, and accepted all of the Hearing Examiner's recommendations.

In late 2004, the Staff launched a series of workshops to begin the development of permanent reliability standards, to be implemented on January 1, 2006.

Summary of December 2004 – April 2005 Workshops

On November 19, 2004, the DPSC Staff informed the Public that a series of six workshops would be held between December 2004 and April 2005; the purpose of which was "to offer members of the public an opportunity to express their viewpoints" on reliability, as well as Staff and public utilities "where several issues had been identified as issues that could benefit from further discussion." The six workshops were structured as follows:

Day – Date – Time	Discussion Topics
Thursday December 16, 2004, 9:00 AM	Regulation overview Company performance General issues/comment
Wednesday January 19, 2005, 9:00 AM	Benchmark standards Service level minimums
Thursday February 10, 2005, 9:00 AM	Infrastructure adequacy Operating constraints
Wednesday March 2, 2005, 9:00 AM	Major event standards (storm & disaster response)
Thursday March 24, 2005, 9:00 AM	Generation interconnection Generation supply adequacy
Wednesday April 14, 2005, 9:00 AM	Reward/penalty structure Attachments Miscellaneous items

As noted earlier, DPL was an active participant on all workshops.

Each of the positions DPL put forward in the workshops has been summarized below:

1. <u>December 16, 2004 (Regulation Overview, Company Performance)</u>
   The primary purpose of this meeting was to launch the series of workshops and to review the history of Docket 50. Staff noted that the goal of the workshops was to create a proposed set of reliability standards regulations that were: "…fair and equitable regulations for the public and utilities". DPL was, and continues to be aligned with Staff's goal for the workshops and the regulations.

2. <u>January 19, 2005 (Benchmark Standards, Service Level Minimums)</u>
   This meeting focused on the reliability standards. Staff noted that "…penalties and rewards around the benchmark were an integral part of the overall effort and would have to be taken into consideration when establishing benchmarks". Staff also noted that they had "…arbitrarily made the three adjustments (from the interim standards) to arrive at new proposed benchmarks." The three arbitrary adjustments were: reduce the standard deviation from 1.75 to 1.0; OMS adjustment factors; and one uniform standard for both utilities (SAIFI 2.0 and CAIDI 120

minutes). In addition, the Forced Outage Rate (FOR) was reduced to no more than 0.1%. The Staff also proposed standards for vegetation management, and construction and maintenance practices.

While continuing to support the process and Staff's desire to have reporting requirements for reliability, DPL raised numerous concerns about the proposed benchmarks. DPL also expressed concerns as to how the benchmarks had been derived, because in some cases it appeared to be—as the Staff noted—arbitrary, and did not take into consideration the randomness of events that affect reliability. DPL proposed that the standards continue to be based on historical performance. DPL also proposed that customer satisfaction measures and complaints to the commission should possibly be taken into consideration in setting reliability targets.

3. February 10, 2005 (Infrastructure Adequacy, Operating Constraints)
At this meeting, DPL presented additional information concerning the standards. Specifically, DPL proposed that the interim regulations be made permanent with the following adjustments:
   - "Using post-OMS data only;
   - Performance targets for each utility based on historical post OMS data;
   - Performance targets based on a rolling five-year average;
   - Abandon Forced Outage Rate, Vegetation Mgmt, and New Construction metrics;
   - Maintain current CELID standard of 24 hours (with $25 penalty);
   - Consider inclusion of the proposed CEMI standard
   - Penalty or reward should be subject to a different standard;
   - Use 2006 as the test year;
   - Set targets and bands for reporting starting in 2007."

   Staff proposed three measures related to the reliability of transmission infrastructure (hours of constrained operation; planning and construction—weather load criteria; and planning and construction—variable reserve margin). In addition, Staff proposed that DPL be mandated to implement a SCADA system to the substation level. DPL raised issues with respect to both the transmission infrastructure benchmarks and to the SCADA proposal. DPL noted that the implementation of SCADA to the substation level could be a significant expenditure for customers to bear.

4. March 2, 2005 (Major Event Standards)
DPL expanded on our objections to some of the specific proposals put forward by Staff at the February 10, 2005 workshop. DPL explained

that we already have in place processes and plans to address worst performing circuits, equipment failures, and pole inspections, and that annual maintenance plans are available to the DPSC. DPL concluded by stating "...adequate procedures were in place to monitor and review equipment failures and their impact. SCADA systems were well positioned to support restoration activities and current transmission system infrastructure exceeds load requirements and pre-restructuring capacity."

Staff went on to review their proposed standards for restoration, but did recognize that there were major differences between major events.

Staff proposed the following restoration standards:

- "80% of customers restored in five days;
- 120 customers restored per crew per day;
- 40 customers restored per responder per day; and
- 95% of customers restored in R days where R-function of damage or storm type or customers out."

Staff noted that a response measure tied to level of damage was probably best, but that there is no clear cut standard available. DPL noted that we already have effective restoration plans in place. Given the variability in major events, DPL saw no reason to establish restoration standards.

5. <u>March 24, 2005 (General Interconnection, Generation Supply Adequacy)</u>
Staff presented the history behind, and their rationale for proposing energy supply standards. The standards proposed were to "...maintain an average facility or source availability factor of at least 85%"; "...maintain an average facility or source forced outage rate of no more than 15%"; and to report performance annually. DPL could not support the proposals because the definition of "electric supplier" used by Staff was not consistent with the legislation; the Equivalent Availability Factor was incorrect; and a number needed to be worked on with PJM.

6. <u>April 14, 2005 (Reward/Penalty Structure)</u>
At this workshop, Staff "...noted that it had taken a worse case situation so that all parties would be aware of the potential impacts of the rewards/penalties to be discussed." Dr. Stutz, a DPSC consultant, reviewed the Rhode Island case and proposed, as was decided in Rhode Island, that a log normal approach to the outage frequency performance curve would lead to a more symmetrical balance between penalties and offsets. DPL reported that if the proposed benchmarks had been in place, DPL would have, for 2004, missed three of the eight standards. DPL reiterated the following adjustments:

- Use post OMS data;
- Use a 1.75 standard deviation to adjust for "normal noise/variability";
- Use a five-year rolling average;
- Maintain the current CELID standards;
- Introduce CEMI;
- Only introduce penalties if rewards are incorporated, and apply penalties to reinvestment in the system and rewards to non-revenue producing investments;
- Do not introduce Major Event, Forced Outage Rate, Constrained Hours of Operation, % Vegetation outages , % Equipment failure outages as standards; and
- The standards should begin in 2008.

Staff concluded the workshop process by indicating that a first draft of the final regulations would be available for comment in approximately 45 days.

Workshop Process

As noted earlier, the Staff has held informal workshops since the beginning of the Commissions exploration as to how electric reliability in Delaware should be addressed. As also noted earlier, DPL has been an active participant and has believed that the workshop process contributed to the understanding of issues, quality of discussion, and ultimately to improved regulatory processes. DPL went into the latest series of workshops believing—as Staff suggested at the initial workshop on December 16, 2005—that the purpose was to have a discussion of issues and create "fair and equitable regulations for the public and the utilities." After reviewing the Staff's August 4, 2005, proposal, DPL wonders whether Staff took any of our views into consideration when finalizing their recommendations. By proposing to mandate additional expenditures which may not contribute to a corresponding improvement in reliability, Staff appears to be asking the public to pay for system enhancements that are of questionable value (e.g., SCADA). Staff also appears to have discounted DPL's reliability and customer satisfaction performance since 2000. DPL believes the workshop process is an effective way of addressing issues and promoting understanding among the parties, but this is only true where all parties can conclude that their comments have had an effect on the outcome.

DPL Performance

Since the beginning of this process, the Commission, Staff, and DPL have all argued that reliability was very important to DPL's Delaware customers and to other stakeholders within the State. In support of this idea, studies by market research organizations and other utilities who have analyzed the relationship between reliability and customer satisfaction have concluded that where there is deterioration in reliability, there is a corresponding reduction in customer satisfaction. Therefore, in considering whether to mandate any standards beyond the interim standards established by Order 6298, it seems to us that DPL's performance and customer satisfaction should be taken into consideration. Below, both DPL's reliability performance and customer satisfaction are presented.

Prior to the implementation of the standards DPL presented data to the Staff demonstrating that the implementation of OMS could cause measured performance to vary by between 0% and 28% for SAIFI and 12% and 48% for CAIDI.

The following tables demonstrate that since 1999, DPL's performance has changed in line with that prediction.

DPL Reliability Performance

Reliability Performance (Excluding Major Events)							
		Pre-OMS			Post OMS		
		1999	2000	2001	2002	2003	2004
DPL	SAIFI	0.98	1.17	.94	1.83	2.15	1.64
	CAIDI	74	89	92	120	131	127
Delaware	SAIFI	1.17	1.01	0.84	1.88	1.87	1.61
	CAIDI	79	76	80	122	127	152

77%
1.01 1.79
78.3 133.7
70.1%

Reliability Performance (Excluding Major Events and Adjusted for OMS*)							
		Adjusted Pre-OMS			Post OMS		
		1999	2000	2001	2002	2003	2004
DPL	SAIFI	1.61	1.92	1.54	1.83	2.15	1.64
	CAIDI	147	178	184	120	131	127
Delaware	SAIFI	1.92	1.65	1.37	1.88	1.87	1.61
	CAIDI	158	152	161	122	127	152

- Adjustment factor of 1.638 applied to SAIFI and 2.003 applied to CAIDI for 1999, 2000 and 2001

61%

Because the "true" impact of OMS on the SAIFI and CAIDI statistics is impossible to determine an indirect approach is the best evidence of whether or not reliability has actually changed over time.

The survey below demonstrates that the customer is generally satisfied with DPL performance

Customer Satisfaction Performance (Market Strategies Inc.)

	ACE and DPL				
Positive ratings (6-10)	**2000**	**2001**	**2002**	**2003**	**2004**
Outcomes					
Overall Satisfaction Measures					
Overall satisfaction	65%	75%	75%	77%	80%
Reliability & Restoration Measures					
Providing reliable electric service	85	86	90	84	89
Having enough electrical capabilities to meet needs	79	78	82	71	76
	Delaware				
Positive ratings (6-10)	**2000**	**2001**	**2002**	**2003**	**2004**
Outcomes					
Overall Satisfaction Measures					
Overall satisfaction	58%	72%	74%	75%	78%
Reliability & Restoration Measures					
Providing reliable electric service	79	86	89	80	88
Having enough electrical capabilities to meet needs	73	80	84	78	85

Implementation Timetable

There continue to be many unresolved issues associated with the exploration and creation of electric service reliability and quality standards within Delaware. Given the normal regulatory process, DPL believes it will be difficult to implement revised standards by January 1, 2006. Therefore, DPL recommends that the interim standards be continued through 2007, and that any revised standards not be put in place until January 1, 2008.

Conclusion

As noted earlier, DPL appreciates the opportunity to comment on Staff's proposed regulations. DPL will continue to be an active participant in this process because we believe electric service reliability and quality are critical to our customers, our employees, and our shareholders. We went into Staff's workshop process believing that the purpose was to establish standards that were fair and equitable to the public and the utilities. We do not believe that the August proposed standards are fair and equitable. We have reached this conclusion because:

1. DPL is already meeting, and has met, the reliability expectations of our customers.
2. Staff has not provided a rationale for why a standard should be implemented.
3. Staff recommendations do not seem to reflect many of the positions put forward by DPL during the workshops.
4. Staff has proposed that the Commission micromanage DPL's maintenance and inspection programs by mandating when and how a program is to operate.
5. Staff has recommended implementing technology without regard to the burden the cost of implementing that new technology may place on the public.
6. Staff has proposed implementing standards in areas where DPL has limited authority or control.
7. Staff has not addressed weather and other aspects of variability that are outside DPL's control.
8. Staff has proposed that the Commission be responsible for assessing penalties for violating the standards while being arbitrary with respect to the size, extent, and duration of the penalties
9. Staff has, with no discussion, eliminated the possible of DPL earning a reward for exceeding benchmarks.

DPL continues to believe that given its historic performance, the Commission and the public are best and most cost-effectively served by having DPL report reliability performance on an annual basis, and by maintaining the customer service standards that are already in place.

Appendix I

Electric Reliability White Paper
Prepared by Staff of the Delaware Public Service Commission
March 20, 2001
(Revised May 1, 2002)

V. Conclusions and Recommendations

1. Based on Staff's findings for the potential for reliability degradation, adopt and implement the reliability standards and reporting requirements as proposed and modified in Regulation Docket 50. How best to achieve compliance with the standards would be left to the discretion of the utility.

2. The Commission should allow the distribution companies to determine the appropriate level of tree trimming required. It should not dictate tree trimming schedules, but should allow Staff's proposed standards to direct the utilities' needs. Nevertheless, the utilities should use their best efforts to take aesthetics into account when performing tree trimming.

3. Staff should continue to take an active role in the transmission planning process and work with PJM to evaluate the effectiveness of the transmission planning process and the congestion management system[2].

4. Staff should take an active role to ensure that the transmission planning process specifically considers transmission adequacy and reliability performance in load

[2] Some consider transmission congestion to be a reliability issue as well as an economic problem. For example, in a recently proposed amendment to Senate Bill 517, the following definition of transmission congestion was provided: "...an operating condition on the transmission system of a regional transmission organization that, if not managed, may cause—"(i) the overload of the transmission system elements; "(ii) depressed voltage; or "(iii) system instability."

pockets. The RTEPP should include provisions for identifying constraints on the transmission system that affect reliability of service to specific areas but that may not have triggered a supply response and/or enhancement or interconnection request due to other constraints (such as lack of adequate gas supply on the Peninsula). Staff should support efforts at PJM's Regional Transmission Expansion Planning Program to identify a mechanism that would provide for transmission enhancements for economic purposes.

5. *The Commission may want to consider supporting a proposal by the TOs at the FERC for performance-based ratemaking for transmission enhancements. Data used in considering the necessity and location of such enhancements should be of sufficient specificity to permit an assessment of the adequacy of transmission service to the Peninsula and other load pockets. If data are collected on a transmission system-wide basis, transmission service in a load pocket may not be detected or adequately monitored. The baseline used in the PBR plan proposed by the TOs should be reviewed to determine its reasonableness. (All available historic data should be incorporated in the development of an appropriate baseline for any performance based ratemaking plan, so that the baseline is not artificially depressed. There is an incentive to reduce performance during a period in which a service provider is knowingly establishing a baseline against which future performance will be measured.) Finally, attention should be paid to the conflicting interests that exist for companies that own both constrained transmission and high cost generation in a load pocket. Any incentives should be carefully considered for their potential impact on a company's participation in the RTEPP or other transmission decisions.*

6. The Commission should work with other state agencies and other states to develop policies that would increase the price responsiveness of demand. Competition is a dynamic process between supply and demand. Most proposals target the supply side, but demand is also critical. A successful load response program would improve reliability as it improves economics.

7. Staff and the Commission should examine existing load management tariffs and customer contracts to ensure that they are structured to realize the full potential of these "negative" resources. EDCs should negotiate with their customers taking service under these tariffs to try to reduce any limitations on the duration, frequency and notice requirements of interruptions allowed under these tariffs, if needed and appropriate.

8. Staff, DEC, Conectiv and PJM should work together to ensure that the data used in system planning are as accurate as possible.

9. The Commission should encourage Delaware, Maryland and Virginia to work together to eliminate any entry barriers to construction of generation, transmission and distribution infrastructure. The appropriate state agencies should examine such barriers as siting, environmental regulations, and limited natural gas deliverability. They should also consider implementing tax and financing strategies to provide incentives for construction of new infrastructure, development of energy efficiency programs and/or development of new technologies.

10. The Commission should direct the EDCs to identify constraints on their transmission[3] systems that affect reliability of service or impose congestion charges in

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[3] The transmission facilities referred to here mean facilities that operate at voltages consistent with those defined in Title 26 §1001of the Delaware Code and should include all such facilities on the Peninsula, including facilities located in Maryland and Virginia.

specific areas of the Peninsula. The modeling used to identify the constraints should reflect the more conservative 90/10 weather normalized peak forecast methodology Such forecasts may be considered in order to understand how the system operates under more severe conditions. The EDCs should determine and report the most effective methods of relieving these constraints or eliminating congestion charges. Factors considered in making this determination should include economic, environmental and other relevant impacts.

11. The Commission should direct the EDCs to forecast the non-weather-normalized peak load for each distribution feeder and use such feeder load forecasts, with and without application of a historical diversity factor, to check the loading of the distribution substation transformers and distribution substation supply circuits that feed them. The loading of equipment under normal conditions is studied by comparing the load being carried by each feeder, distribution substation transformer, and distribution substation supply circuit with their normal equipment ratings with all facilities in service. The loading of substation equipment under operating contingencies should be studied by comparing the load being carried by each distribution substation transformer and each distribution substation supply circuit with their emergency equipment ratings in different study scenarios, each with one distribution substation transformer or one distribution substation supply circuit out of service.[4]

12. The Governor's State Energy Plan should be fully supported at both the task force and working group levels.

[4] Loading on distribution feeders is sometimes planned such that the feeder, operating under an emergency rating, can pick up a portion of the load from an adjacent feeder through the use of ties between the feeders out in the field.

13. The funds that have been collected from the "environmental incentive" assessment that are not already being used for rebates for photovoltaics and solar hot water heaters should be used to develop energy efficiency programs, such as: (1) the purchase of interval meters for residential customers so that they can participate in economic load management plans; (2) the providing of incentives to purchase and use energy efficient products; and (3) the development and use of environmentally sound energy efficient resources.

14. Delaware, Virginia and Maryland should develop a comprehensive energy policy for the Peninsula. The first step in this process should be the evaluation and determination of the most feasible and cost-effective energy efficiency, demand side, and distributed generation strategies. The next step would then be to determine how these strategies can and should be financed. Once developed, this policy could be used by DEDO to determine the most appropriate use of the funds collected through the environmental incentive assessment.

15. Staff recommends that each utility and PJM evaluate the usefulness of probabilistic analyses as a tool to examine its transmission system and, if appropriate, incorporate it into its transmission adequacy evaluations. However, Staff's reliability index recommendations contained in the reliability standards and reporting requirements in Regulation Docket 50 published by the Commission are designed to motivate electric utilities to perform at a predetermined minimum reliability level. This performance-based approach allows flexibility and puts the burden of determining the appropriate action on the utility. This approach further allows the Commission and Staff to evaluate the utilities' *performance after the fact based on measurable criteria without dictating the utilities' actions to meet the requirements or its transmission evaluation methods.*

Appendix II

Report of the Hearing Examiner
Robert P. Haynes
November 5, 2003

Discussion

"16. The performance standards were based upon DP&L's and DEC's pre-restructuring levels of performance, as adjusted for a 1.75 standard deviation for data variability and the change to a computerized record keeping known as an outage management system ("OMS"). The interim standards in the proposed rules are acceptable to both utilities, and are based upon recognized industry indices, namely, the System Average Interruption Frequency Index ("SAIFI") and the Customer Average Interruption Duration Index ("CAIDI").

17. Under the proposed rules' performance standards, DP&L would have a SAIFI of 2.3 times, or a customer average outage of 2.3 times per reporting period. DP&L's CAIDI standard would be 141 minutes, which means that an average outage would last 141 minutes. DEC's SAIFI would be 4.6 times and its CAIDI would be 173 minutes. The proposed rules' reporting periods are annually and a rolling three-year average. Both utilities will have an average 'Forced Outage Rate' limit of one percent of a facility's time in operation. These standards are interim and shall apply through 2005. I find that the performance standards are reasonable, particularly as the utilities accepted them.

18. The proposed rules' performance standards are expressly not to be used to penalize the utilities for any non-compliance. I agree that this is prudent since there are many uncertainties in the change from a manual reporting system to an OMS, as discussed later in this report. The proposed rules also remove from the performance standards' calculations any outage data from a "major event," as defined by the industry. Again, this is appropriate insofar as a major event could distort the data, which is designed to measure reliability under normal operations. Information on major event outages will still be reported to the Commission.

19. The proposed rules will require the utilities to submit annually a Planning and Studies Report and a Performance Report. These reports are to detail the utilities' plans to improve their performance and how they performed in the historic reporting periods. In addition, the utilities are to notify the Commission of a major event within thirty-six hours and submit a Major Event Report within fifteen days afterwards. A major event is defined by the accepted industry standard definition set forth in The Institute of Electrical and Electronics Engineers, Inc. ("I.E.E.E") Standard 1366.

20. In addition, the proposed rules will require that the electric utilities install an outage management system ("OMS"), which is defined "as a software system that provides database information to effectively manage service interruptions and minimize customer outage times." The record indicates that DP&L has an OMS that already is in operation; while DEC's OMS should be in operation by the time the proposed rules go into effect as regulations."