THE BOARD OF COMMISSIONERS OF PUBLIC UTILITIES

<u>IN THE MATTER OF</u> the *Public Utilities Act*, R.S.N. 1990, Chapter P-47 (the "Act"),

AND

<u>IN THE MATTER OF</u> a General Rate Application (the "Application") by Newfoundland and Labrador Hydro for approvals of, under Section 70 of the Act, changes in the rates to be charged for the supply of power and energy to Newfoundland Power, Rural Customers and Industrial Customers; and under Section 71 of the Act, changes in the Rules and Regulations applicable to the supply of electricity to Rural Customers.

PRE-FILED EVIDENCE
OF
C. DOUGLAS BOWMAN

October 27, 2006

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Evidence Outline

List of Exhibits

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My name is Doug Bowman. This document was prepared by myself, and is correct to the best of my knowledge and belief. I have been retained by the Government appointed Consumer Advocate to provide expert advice and evidence to the Consumer Advocate in response to Newfoundland and Labrador Hydro's ("Hydro's") application for approval of certain changes to its rates, charges and regulations. In particular, this evidence documents the results of my review of Hydro's proposed cost of service and rate design, and provides some general comments regarding the Application.

This document was prepared with the understanding that issues related to cost of service, rate design and the rate stabilization plan have been settled with the exceptions noted in the Parties' October 20, 2006 Agreement on Cost of Service, Rate Design and Rate Stabilization Plan. Therefore, issues that are part of the negotiated settlement are not addressed in this evidence.

A summary of my background and qualifications is provided in ***Exhibit CDB-1***. I have both a B.S. and an M.S. in Electrical Engineering from the State University of New York at Buffalo and 29 years experience in the electricity services and consulting industry. My primary expertise includes power sector restructuring, regulation and markets, and electricity services costing and pricing. I am currently an independent Energy Consultant working out of my office located in Warrenton, Virginia.

Prior to becoming an independent consultant, I was employed by KEMA Consulting, Nexant Inc., Pace Global Energy Services, International Resources Group, CSA Energy Consultants and Ontario Hydro. I have testified before this Board four times previously as an expert witness on cost of service and rate design at Newfoundland Light and Power Company Limited's ("Newfoundland Power's") 1996 *Application by Petition for Approval of Certain Revisions to its Rate, Charges and Regulations*, at Hydro's 2001 *General Rate Proceeding*, at Newfoundland Power's 2003 *General Rate Application* and at Hydro's 2003 *General Rate Application*. I have also appeared twice before the Nova Scotia Utility and Review Board as an expert witness on cost of service and rate design, and while at Ontario Hydro, I was involved with the regulatory process in the areas of generation and transmission planning, demand/supply integration, operations, rate design and customer service.

Section 1 of my Pre-filed Evidence summarizes my review of Hydro's evidence with regard to this Application; **Section 2** provides a review of proposed changes to the rate stabilization plan (RSP); **Section 3** provides a review of the NP generation credit; and

Section 4 provides a number of comments relating to Hydro's commitment to operational excellence in providing least cost, reliable power to the consumers of the Province, specifically, integrated resource planning, customer value of service, external benchmarking of key areas of performance and performance-based regulation.

1. Summary of Evidence

A summary of my review of Hydro's Application follows:

a) In the Parties' October 20, 2006 Agreement on Cost of Service, Rate Design and Rate Stabilization Plan, it was agreed that Hydro will initiate a review of the RSP in 2007 with the intent to better reflect design objectives. It was further agreed that Hydro would use best efforts to achieve an implementation date of January 1, 2008. With regard to this Application, RSP issues related to limitations on the potential effects on Hydro's net income of variations in Rural diesel fuel costs and Rural power purchase costs and the full or partial closure of the CFB Goose Bay facility on Hydro's net income are to be resolved. These are significant design changes that as proposed, will further distort the price signal for marginal consumption by Industrial Customers (ICs) and Newfoundland Power (NP), and further confuse an RSP formula that is already overly complicated and lacking in transparency. I therefore recommend that the Board refuse implementation of these additions to the RSP pending the outcome of the 2007 RSP review.

b) A report prepared on Hydro's behalf (Exhibit RDG-2) recommends that the existing mechanism that credits NP for its hydraulic and thermal generation in the Cost of Service be continued with some modifications to the valuation methodology. However, the current credit mechanism and valuation methodology for NP generation, although consistent with previous Board Orders, is not consistent with regulatory precedent. I recommend that the credit mechanism and valuation methodology for all customer-owned generation be based on a system of power purchase contracts with values reflecting Hydro's avoided costs. It will take some time to develop such contracts. Until the contracts are developed, the current methodology without modification should be continued because it represents a negotiated settlement among the parties as reflected in Board Orders.

c) In the Corporate Overview evidence, Mr. Martin states "Hydro is committed to operational excellence in providing least cost, reliable power to the consumers of the Province" (page 12, lines 2 to 3). I have a number of points to make relating to Hydro's goal of "operational excellence", as follows:

- Decisions relating to demand and supply procurement have long-term effects on the cost of power, and indirectly, the competitiveness of industry in the Province. As a result, a comprehensive planning framework is necessary to increase confidence that customers are gaining maximum value from demand and supply procurement programs from both cost and socio-environmental perspectives.
- Hydro's reliability initiative including its target 20% reliability improvement is not associated with a clearly defined policy or procedure identifying minimum reliability performance benchmarks. In the absence of such a policy or procedure, it is not possible to properly audit the appropriateness of reliability-related expenditures.

- Hydro is not tracking performance in a number of areas that may be of key interest to consumers.
- Hydro is not externally benchmarking its performance relative to a peer group in an effort to identify areas requiring improvement.
- Performance-based regulation (PBR) is a more light-handed form of regulation that has the potential to provide a number of benefits to the Province while encouraging improved performance by Hydro. It is consistent with Hydro's goal of operational excellence. Hydro expressed its support for considering PBR by signing on to the Mediator's Report (Appendix H of the *Decision and Order of the Board No. P.U. 14 2004)* which requested that the Board prepare or obtain a report on PBR alternatives for Hydro and NP.

With these points in mind, I recommend the following as means for Hydro to achieve its goal of operational excellence:

- The Board direct Hydro to prepare and submit to the Board for review and approval a detailed framework and schedule for undertaking a formal integrated resource plan;
- The Board direct Hydro to prepare a clear reliability policy or procedure identifying minimum reliability performance benchmarks upon which to evaluate and audit reliability expenditures. Hydro should submit the policy or procedure to the Board for stakeholder review and Board approval. Following Board approval, Hydro should re-submit for Board approval its

reliability improvement plan consistent with the new policy along with a detailed cost estimate and schedule for implementation;

- The Board direct Hydro to initiate tracking and reporting of performance relating to the indicators requested in CA 2 NLH and CA 3 NLH and canvass customers concerning the value they place on such performance; and
- The Board direct Hydro to initiate reporting of key performance indicators (KPIs) in Exhibit JRH-1 with performance externally benchmarked to a comparable peer group as Hydro agreed to do in the Mediation Report (Appendix H of the *Decision and Order of the Board No. P.U. 14 2004)*.

2. Rate Stabilization Plan (RSP)

In the Parties' October 20, 2006 Agreement on Cost of Service, Rate Design and Rate Stabilization Plan, it was agreed that Hydro will initiate a review of the RSP in 2007 with the intent to better reflect design objectives. It was further agreed that Hydro would use best efforts to achieve an implementation date of January 1, 2008.

With regard to this Application, the following RSP-related issues have yet to be resolved:

i. Whether there should be any limitations on the potential effects of variations in Rural diesel fuel costs and Rural power purchase costs on Hydro's net income;
ii. Whether there should be any limitations on the potential effects of the full or partial closure of the CFB Goose Bay facility on

Hydro’s net income; and

iii. The disposition of the forecast hydraulic production variation balance in the RSP.

Changes to the RSP relating to CFB Goose Bay and Rural diesel fuel and power purchase costs are significant design changes. Currently, RSP balances are recovered through an adder applied to energy consumption. As stated in the July 2006 report entitled *Implications of Marginal Cost Results for Class Revenue Allocation and Rate Design* (attached to PUB 1 NLH) the production cost at Holyrood defines marginal energy costs throughout the year (page 1). As changes in consumption at the CFB Goose Bay facility and in prices of Rural diesel fuel and power purchases are in no way related to Holyrood production costs, recovery of costs resulting from such changes in the RSP adjustment distort the energy price signal in IC and NP rates.

Moreover, the addition of terms to the RSP for CFB Goose Bay and Rural diesel fuel and power purchase costs would further confuse an RSP formula that is already overly complicated and lacking in transparency. Given the Parties have agreed to review the RSP and consider its simplification by separately tracking provisions not related to the hydraulic and fuel price components of the plan through an accounting mechanism discrete from the RSP (see Paragraph 14 (iv) of Agreement), I recommend that the Board refuse to entertain these changes pending the outcome of the 2007 RSP review.

With regard to the disposition of the RSP balance resulting from the hydraulic production variation, a proposal has not yet been put forward, so I am unable to comment. However, if such a proposal is put before the Board, I recommend that it be considered for approval only if consistent with the parameters set out for the 2007 RSP review in the Parties' Agreement.

3. Newfoundland Power Generation Credit

Currently, Newfoundland Power receives a credit in the cost of service study for its thermal and hydro generation. The credit is based on the perceived value of the generation from an embedded cost perspective. The credit mechanism has been debated at previous Hydro rate applications. Following Hydro's 2003 GRA, the Board ordered Hydro to file a report on the matter (P.U. 14 (2004)). The subsequent report dated February 3, 2006 entitled *Review of Newfoundland and Labrador Hydro's Treatment of Newfoundland Power's Generation* is filed as Exhibit RDG-2.

The authors of the report recommend continuation of the existing mechanism that credits NP for its hydraulic and thermal generation in the Cost of Service, and proposes two principal modifications relating to the valuation, or compensation, for NP generation (pages 22 to 23), as follows:

- The existing thermal credit mechanism's impact on load factor and the resulting change in cost classification should not form part of the compensation since the attendant change in load factor is not related to cost causation; and

- Hydro should discontinue compensation for transmission because: 1) thermal generation is not forecast to be run during system peak and therefore should not reduce NP's common transmission cost allocation; and 2) Hydro's analysis shows that there is no avoided transmission cost associated with NP thermal generation.

The report also recommends that if the Board considers other options such as direct payment to NP based on Hydro's avoided costs or the use of a proxy unit, it should factor in related considerations, such as age and reliability of NP's units as well as shared use between NP and Hydro.

In a review of customer-owned generation such as this, there are two principal questions to answer: 1) What is the appropriate mechanism for compensating customer-owned generation, and 2) What is the appropriate basis for valuing the generation? These questions are addressed below.

3.1 Compensation Mechanism

I have a number of points to make concerning the current compensation mechanism, as follows:

- The current mechanism is consistent with previous Board Orders. Although not perfect, it represents a negotiated settlement among the Parties as reflected in Board Orders. If a change is proposed, the impact on other elements of the cost of service methodology must also be considered, for example, its consistency with treatment of IC-owned generation.

- Any change should be consistent with regulatory precedent and should take into consideration experience in competitive markets.
- In Exhibit RDG-2, no changes are proposed to the compensation mechanism whereby a credit is provided in the cost of service. However, in the response to CA 14 NLH, Mr. Greneman indicates he is not aware of any other jurisdiction that applies a generation credit in the cost of service study. He notes that in order to encourage alternative generation sources such as wind and solar, generation that is embedded in a distribution system is typically addressed through net metering (i.e., the demand NP places on the system, meaning NP's gross demand net of its generation) with no explicit credit in the cost of service study. In effect, Hydro would purchase NP's generation at the wholesale price of electricity.
- A number of states in the U.S. require utilities to offer net metering to customers with generation. PacifiCorp offers net metering in all states that it operates whether required or not (page 86, PacifiCorp 2004 Integrated Resource Plan: http://www.utahpower.net/File/File47422.pdf).
- A net metering approach for NP's hydro generation would be consistent with regulatory precedent as Mr. Greneman suggests. It would also be consistent with efforts to promote such things as DSM/conservation and renewable generation.
- Hydro raises a number of concerns with net metering (see response to CA 198 NLH), but these concerns have been addressed in other jurisdictions and could be similarly addressed in this Province. It would likely require changes in the

NP wholesale rate design such as spreading the demand charge over all winter months rather applying it to the single annual peak as it is today. Such changes in the wholesale rate design are proposed for study in 2007 in the October 20, 2006 Parties' Agreement.

- As the authors of the report state, NP thermal generation has value to Hydro's Island Interconnected System and benefits all customers (page 22). The value of NP's thermal generation relates primarily to capacity, so a power purchase contract may be the most effective mechanism for conveying compensation to NP. The contract would specify payment and related terms and conditions. A contract mechanism could also be used to compensate NP for its hydro generation as an alternative to a net metering approach, particularly if Hydro feels it is not feasible to address its wholesale rate design concerns. In effect, NP generation would be treated much the same as the non-utility generators (NUGs). As the Board's consultants recommended in the 2003 GRA, a generation tariff in lieu of a generation credit would ensure that financial transactions correspond to the operational flow of energy, thereby making it more transparent and robust (see Exhibit RDG-2, page 4, section 2.2.2). A contract approach to customer-owned generation would also have the following benefits:
    - It would formalize an arm's length business arrangement between Hydro and Newfoundland Power that is not in place today;

- It would formally grant Hydro control over these assets during emergency situations, thus enhancing its ability to maintain system reliability; and
- It would treat Newfoundland Power generation on a consistent basis with other generators in the Province both operationally and financially.

3.2 Basis for Valuation

Currently, NP's generation is valued on the basis of Hydro's average embedded costs (page 22, Exhibit RDG-2). As already stated, the authors of Exhibit RDG-2 recommend that the impact of NP's thermal generation be removed from the load factor and resulting change in cost classification, and that there be no credit for transmission associated with NP's thermal generation.

Following are a number of points relating to the valuation of NP thermal generation:

- Generation capacity relates to the ability of a generator to provide energy when called upon, and therefore is a measure of reliability. It makes no difference how often a generator is called upon to provide energy, only that it be able to provide the energy when needed. It is common in the industry for peaking generators to be operated infrequently, perhaps less than 1% of the time. The amount a generator is dispatched does not reduce the generator's capacity value – operationally, only the generator's rated capacity and its availability impact on the value of its capacity.

- The authors of the report indicate that their preferred option is to credit NP's thermal generation based on Hydro's average embedded cost, and that compensation for transmission be discontinued on the basis that there is no avoided transmission cost associated with NP thermal generation. There is an inconsistency in valuing transmission, but not generation, on the basis of avoided cost.
- The authors of the report indicate that should the Board consider other options such as avoided costs or use of a proxy unit that it should factor in related considerations such as age and reliability of NP's thermal units, as well as shared use between NP and Hydro. I am not aware of any jurisdiction that factors age into such a valuation – reliability certainly, but not age. In any case, I note that NP has undertaken major refurbishments on 86% of its thermal generation capacity (see Exhibit 8 of Exhibit RDG-2) implying that the reliability of these units may be much better than generators of the same vintage that have not had major refurbishments. With regard to shared use between Hydro and NP, compensation is based on the value of the capacity to Hydro - it is not clear why the valuation should also factor in shared use between NP and Hydro. The response to CA 15 NLH states that instances of sharing splits for thermal generation embedded in a distribution system in other jurisdictions have not been studied, so the report offers little guidance to the Board in this regard.

- The electricity markets located in the northeastern United States, specifically PJM, New York and New England, all have generation capacity markets.[1] In each case, the value of generation capacity is based on the annualized cost of the favoured peaking generation option, often a simple cycle turbine. Fixed annual operation and maintenance costs (i.e., costs that do not vary with energy production such as property taxes, insurance, fixed portion of labour, etc.) are included in the valuation. In New York, the "unforced capacity" or "available capacity" of a generating unit is defined as its installed capacity multiplied by its availability, in effect:

  Installed Capacity * (1 – Unit's Equivalent Forced Outage Rate)

  The age of the generator and the number of hours dispatched are not factors in the valuation; neither is there any consideration given to shared value.

- Generation and transmission avoided costs will vary over time in response to changing demand and supply balance. For example, the marginal cost of generation capacity in the Province is judged to be quite low at this time owing to the capacity surplus and high cost of fuel at Holyrood. In addition, Hydro's analysis shows there is no avoided transmission cost associated with NP generation at the present time. However, NP generation has been in service for a long period of time, and is expected to remain in service well into the future. Therefore, although its value will fluctuate, it would be expected to average the full levelized cost of a peaker and the full levelized cost of

[1] See August 25, 2005 *Capacity Markets White Paper* by the California Public Utilities Commission, http://www.cpuc.ca.gov/published/REPORT/48884.htm.

avoided transmission over its life. It is inappropriate to consider a snapshot in time for such valuations because at some point in the past, or at some point in the future, NP generation did/will help Hydro avoid costly additions of generation and transmission capacity.

- Because NP generation is located on the distribution system and closer to the load, it reduces capacity losses sustained on Hydro's transmission system.

3.3 Summary

Although consistent with previous Board Orders, the current mechanism that conveys compensation for NP generation through a credit in the cost of service is not consistent with regulatory precedent in other jurisdictions. A contract approach, or a combination contract approach for thermal generation and net metering approach for hydro generation, is consistent with regulatory precedent and experience in competitive markets. A contract approach for all customer-owned generation would formalize an arm's length arrangement between Hydro and NP, grant Hydro control over all generation assets during emergency situations thus improving reliability, and would treat NP generation on a consistent basis with other generators in the Province.

With regard to the level of compensation, it is common in the industry to value generation capacity based on the levelized cost of a peaker. The authors of the report in Exhibit RDG-2 include this as one of the valuation options considered, but do not recommend it. It is also common to incorporate fixed operation and maintenance costs in the value, along with the levelized cost of avoided transmission and losses. The value of the generation capacity is based on the generator's installed capacity adjusted for availability.

In summary, the current capacity credit mechanism is controversial and inconsistent with regulatory precedent. I recommend that the credit mechanism and valuation methodology for all customer-owned generation be based on a system of power purchase contracts with values based on Hydro's avoided costs. It will take some time to develop such contracts. Until the contracts are developed, the current methodology without modification should be continued because it represents a negotiated settlement among the parties as reflected in Board Orders.

4. Hydro's Commitment to Operational Excellence

In the Corporate Overview evidence (Section 4, pages 12 through 19), Mr. Martin discusses Hydro's commitment to operational excellence. A number of quotes from Mr. Martin's evidence follow:

- Hydro is committed to operational excellence in providing least cost, reliable power to the consumers of the Province (page 12, lines 2 – 3);
- The prudent management of costs, without compromising safety and appropriate levels of reliability, is standard operational practice. Customers require a reliable supply of energy but are also clear they want electricity rates to remain at reasonable levels (page 12, lines 13 to 16);

- Hydro has been successful in minimizing the impact of rising operational costs and tracking below inflation over the five year period from 2002 to 2007 (Chart 5, page 13, 1st Revision September 18, 2006);
- Hydro is tackling rising fuel costs through energy conservation, development of alternative generation sources (i.e., wind) and future hydro developments (pages 15 to 16);
- Hydro balances capital and operating investments to ensure appropriate reliability levels are maintained. Annually, Hydro invests significantly in the system to ensure the reliability of the provincial electricity system, and from 2001 to 2005, Hydro invested $182 million in capital system upgrades and improvements (page 16, lines 23 to 27); and
- Residential customer service satisfaction has been maintained at 93% from 2003 to 2005 (page 19, lines 3 to 4).

It is within the context of these statements that I discuss a number of issues relating to Hydro's commitment to operational excellence, including integrated resource planning, customer value of electricity service, external benchmarking of costs and performance, and performance-based regulation.

4.1 Integrated Resource Planning

Decisions relating to demand and supply procurement have long-term effects on the cost of power, and indirectly, the competitiveness of industry. For example, the decision to build Holyrood 25 to 35 years ago has resulted in a system where 43% of Hydro's 2007 test year expenses relate to the cost and associated volatility of No. 6 fuel (page 2 of 2, Schedule III, M.G. Bradbury). This is not to suggest that Holyrood was a bad business decision; it is meant only to drive home the point that supply procurement decisions influence costs for many years into the future. As a result, a comprehensive planning framework is necessary to provide confidence that customers are gaining maximum value from demand and supply procurement programs from both cost and socio-environmental perspectives.

In spite of the undeniable importance of such planning, Hydro acknowledges that it has not prepared a complete integrated resource plan (IRP) to meet future energy needs in the Province in a least cost and socio-environmentally responsible manner (see response to CA 31 NLH). In the absence of such a plan, the Board and stakeholders do not have adequate information upon which to review Hydro's procurement and operations proposals. For example, in the absence of an approved plan, it is not clear if fuel and maintenance expenditures on Holyrood, a significant source of pollution, are consistent with conservation/DSM, renewable energy, environmental initiatives and Holyrood's long-term operating regime.

Development of IRPs with full public review is common in the United States. All customers of the Western Area Power Administration (WAPA), an agency of the U.S. Department of Energy, must periodically file integrated resource plans. WAPA markets and delivers hydro power and related services within a 15-state region of the central and western U.S. with over 750 customers[2]. WAPA defines IRP as follows[3]:

> *"a planning process for energy resources that evaluates the full range of alternatives, including new generating capacity, power purchases, energy conservation and efficiency, cogeneration and district heating and cooling applications and renewable energy resources, to provide adequate and reliable service to a customer's electric consumers at the customer's or member's lowest system cost. The process considers necessary features for system operation, such as diversity, reliability, dispatchability and other risk factors; looks at ways to verify energy savings gained through energy efficiency, and the projected life cycle of such savings; and consistently integrates demand and supply resources".*

WAPA provides an IRP plan checklist at http://www.wapa.gov/es/irp/IRPchecklist.htm.

In summary, demand and supply procurement decisions have long-term effects on the cost of power. An integrated resource plan with full public input is necessary to properly assess the risks of such decisions and provide confidence that consumers are gaining maximum value from both cost and socio-environmental perspectives.

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[2] See website: http://www.wapa.gov/about/default.htm
[3] See website: http://www.wapa.gov/es/about/faqirp.htm

4.2 Customer Value of Electricity Service

I struggle to understand some of Hydro's responses to requests for information (RFIs) relating to customer value of service, in particular, Hydro's 20% target reliability improvement (see page 22 of Exhibit JRH-1). In any case, I explain what I do understand in the following:

- There are already capital and operating and maintenance costs associated with maintaining current levels of reliability on the system. Mr. Martin states in his evidence (page 16, lines 25 to 27) "Annually, Hydro invests significantly in the system to ensure the reliability of the provincial electricity system, and from 2001 to 2005, Hydro invested $182 million in capital system upgrades and improvements".
- If an improvement in reliability is targeted, there will be additional costs beyond the cost to maintain current levels of reliability, and this additional cost increases dramatically as higher levels of reliability are targeted; i.e., when the point of diminishing returns is reached.
- Hydro indicates that it targets a 20% reliability improvement against its most recent five-year rolling average reliability performance (page 3, 21 and 22 of Exhibit JRH-1, and CA 56 NLH). I understand from Exhibit JRH-1 that this 20% improvement target is applied annually, although I have not seen a formal plan or policy relating to Hydro's reliability improvement effort going forward. If a 20% improvement target were to be applied on an annual basis, I suspect it would not be

long before the cost associated with its pursuit of this target became exceedingly high and burdensome to ratepayers.

- It is apparent that Hydro does not have a Board-approved policy or procedure including a minimum benchmark of reliability performance beyond which no further reliability expenditures would be required. Other jurisdictions establish such reliability performance procedures and benchmarks. For example, the Pennsylvania Code requires electricity distribution companies to design and maintain procedures to achieve the reliability performance benchmarks and minimum performance standards established by the Commission[4].
- Likewise, the Delaware Public Service Commission has recently established an *Electricity Service Reliability and Quality Standards* regulation through Order No. 7002[5]. The order and regulation are included in ***Exhibit CDB-2***. The purpose of this Order is to set forth reliability standards and reporting requirements needed to assure the continued reliability and quality of electric service being delivered to Delaware electricity customers. Compliance with the regulation is a minimum standard. Each distribution company is required to have targeted objectives, programs and/or procedures and forecast load

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[4] See website: http://www.pacode.com/secure/data/052/chapter57/subchapNtoc.html

[5] For Commission Order and Electric Service Reliability and Quality Standards regulation see website: http://www.state.de.us/delpsc/orders/7002.pdf. For Delmarva Power & Light Company's filings see: http://www.state.de.us/delpsc/electric/dpl06planrpt.pdf for the 2006 Planning and Studies Report and http://www.state.de.us/delpsc/electric/dpl05perfrpt.pdf for the 2006 Annual Performance Report.

studies, designed to help maintain acceptable reliability level for its delivery facilities, and where appropriate, to improve performance. Each distribution company is required to submit annually to the Commission a Planning and Studies Report identifying its current year's annual objectives, planned actions and projects, programs and forecast studies that serve to maintain reliability and quality of service at an acceptable reliability level. In addition, each distribution company is required to submit annually to the Commission a Performance Report that assesses the achievement of the previous year's objectives, planned actions, projects and programs, and assesses the relative accuracy of forecast studies and previous year performance measures with respect to benchmarks. Current benchmarks are based on pre-restructuring levels of SAIDI (295 minutes per customer for Delmarva and 635 minutes per customer for Delaware Electric Cooperative). Each distribution company is also required to track its annual and three-year average performance against the benchmarks, and track and report its annual performance in other areas of reliability such as CAIDI, SAIFI, etc.

- Reliability regulations such as the one in Delaware provide a comprehensive audit trail against which the Commission can evaluate performance and gauge the value to consumers of reliability-related expenditures. I note that neither Pennsylvania nor Delaware have implemented performance-based regulatory mechanisms.

- Minimum reliability performance benchmarks might be based on a number of inputs, such as historical experience, customer surveys and experience in other jurisdictions. In Delaware, they are based on historical experience tied to levels prior to restructuring – Delaware is attempting to guard against deteriorating reliability resulting from greater competitive pressures. In its response to CA 56 NLH, Hydro indicates it based its 20% improvement target on historical experience and performance relative to comparable utilities, although the only other utility in respect of which it has provided any information is Newfoundland Power. The response to CA 188 NLH shows that SAIDI and SAIFI indexes for Hydro's customers are generally poorer than those for NP customers, but that is to be expected given the remoteness and lower customer densities of Hydro's distribution system. It is common to have different reliability benchmarks for different utilities. For example, Delaware's Commission established a minimum SAIDI benchmark of 295 minutes per customer for Delmarva, and 635 minutes per customer for Delaware Electric Cooperative which like Hydro, tends to serve more rural areas with lower customer densities. The Delaware SAIDI benchmarks for Delmarva and Delaware Electric Cooperative are comparable to recent SAIDI statistics for NP and Hydro, respectively.
- Customer surveys are often used as an indicator of customer value of service. Hydro indicates that its customer surveys provide a key

insight on customer expectations and are used as one of the qualitative inputs into its assessment of the appropriate balance between cost and reliability (CA 1 NLH).

- Hydro’s 2005 customer surveys show that over the past five years, 95% of residential customers have indicated that service reliability met or exceeded expectations, and less than 2% of residential customers have been somewhat or very dissatisfied with service reliability (pages 30 – 33 of the 2005 Residential Customer Tracking Study attached to CA 1 NLH). Likewise, 93% of commercial customers indicated that service reliability met or exceeded expectations, and about 2% have been somewhat or very dissatisfied with service reliability (pages 24 – 25 of the 2005 Commercial Customer Satisfaction Study attached to CA 1 NLH). Obviously, the percentage of Hydro’s customers that are unhappy with current levels of reliability is small.
- Hydro’s 2005 customer surveys also show that about 50% of residential customers prefer lower electricity rates over “getting the most reliable service possible which means less and/or shorter outages even though they may have to pay extra”. About 40% of residential customers prefer “the most reliable service possible” (page 33 of the 2005 Residential Customer Tracking Study attached to CA 1 NLH). For commercial customers, the results were split about evenly, with 44% preferring lower rates and 44% preferring “the most reliable service possible” (page 28 of the 2005 Commercial Customer

Satisfaction Study attached to CA 1 NLH). It must be recognized that this statistic has only limited value as customers claiming that they prefer “getting the most reliable service possible even though they may have to pay extra” means little when the question is not accompanied with information relating to the extra amount that they may have to pay, and the associated increase in reliability. For example, I suspect most every customer would be willing to pay another dollar per year for 100% reliability.

In summary, the problem I see with Hydro’s 20% target reliability improvement is that there is no formal policy or procedure with minimum reliability performance benchmarks. This makes it difficult to conduct a proper audit of reliability expenditures, an extremely important consideration given the high value customers place on reliable service, and the high level of expenditures necessary to maintain adequate reliability. A formal reliability policy with minimum performance benchmarks will ensure that in future rate and capital budget proceedings the Board and stakeholders will be able to properly assess and determine in an evidence-based manner if reliability performance is adequate, and if reliability expenditures are indeed warranted.

Before leaving the customer value of service theme, I note that Hydro lists as one of its goals that “Through operational excellence, we will provide exceptional value to all consumers of our energy” (see Goal # 5 on page 4 of April 2006 report entitled *Strategic Goals and Objectives for Newfoundland and Labrador Hydro* attached to CA-5). In its response to CA 2 NLH, Hydro states that it still[6] does not track such things as number of customer complaints per 1000 customers, percent of customer calls answered within 30 seconds, percent of customer outage calls answered and percent of new customer services installed and energized by the date promised to the customer (see response to CA 2 NLH). Neither does Hydro appear to know the number of hours of service outages that its customers are willing to accept (see response to CA 3 NLH), and Hydro has not determined the correlation between money spent and resulting improvements in reliability. Without such information, the Board, stakeholders and Hydro itself are deprived of the information necessary to make an evidence-based determination whether Hydro is bringing "exceptional value to consumers" and indeed meeting its performance with respect to Goal # 5.

The correlation between investment and resulting impacts on reliability are indeed of increasing interest to distribution utilities and regulators. I note that EPRI Solutions is currently undertaking a study entitled *Investing in the 21st Century Distribution System*[7]. The prospectus indicates that EPRI Solutions provides an integrated portfolio of engineering services, business consulting and information products to deliver immediate benefits and lasting value to power industry clients. The Electric Power Research Institute (EPRI) is its parent organization.

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[6] Neither did Hydro track its performance in these areas in 2003 as pointed out in my evidence submitted at the 2003 GRA.
[7] See website: http://www.eprisolutions.com/Downloads/DistributionSystemProspectus_ESI.pdf

The EPRI Solutions study prospectus is provided in ***Exhibit CDB-3***. The study will provide a detailed technical and business analysis of the relationship between investment levels in distribution system enhancement and the expected impacts on reliability and quality. A key issue to be addressed is the strategies that utilities and regulators have agreed are the most effective for addressing reliability and quality improvement needs. The prospectus states the reasons why this study is important now:

- Reliability and quality of service are becoming more critical factors in the regulation of distribution companies; and
- Investment requirements to achieve improved reliability and power quality may be one of the most important aspects of many rate case filings.

There are a number of additional performance indicators that Hydro should track in its effort to achieve performance excellence. In addition, it is important that Hydro establish a correlation between investment and resulting impacts on reliability. The EPRI Solutions study results, once available, could provide valuable insights in this regard.

4.3 External Benchmarking of Costs and Performance

In the Mediator's Report included in Appendix H of the *Decision and Order of the Board (Order No. P.U. 14 2004)*, Hydro agreed (point "aa") to "propose a peer group of utilities and measures upon which to compare its performance not later than six months following the date of the Board Order in this proceeding. Upon approval thereof, Hydro will collect and report such measures for itself and the peer group annually beginning in 2005".

While key performance indicators (“KPIs”) have been developed and reported (Exhibit JRH-1), and a peer group has been recommended (December 2004 report entitled *Defining a Utility Peer Group for Newfoundland and Labrador Hydro*), Hydro has not reported statistics comparing its performance to that of an external peer group. It has been three years since Hydro agreed in the 2003 GRA Mediation Report to start reporting such information.

In its response to CA 4 NLH, Hydro indicates it has not received further direction from the Board arising from its peer group report, and CEA published a policy paper on benchmarking data in regulatory settings that states “due to the complexity of peer benchmarking, trending the performance of an individual utility over time was recommended as opposed to peer-to-peer benchmarking”. Hydro’s response goes on to say that CEA’s work on regulatory KPIs remains ongoing and as a result, Hydro has not engaged in any external benchmarking.

Hydro’s response is very disappointing and draws into question the credibility of the mediation/negotiation process. The mediation agreement was not premised on CEA policy and, apparently Hydro did not follow up with the Board to indicate it was awaiting approval of the peer group report (see response to CA 179 NLH). There are numerous other sources for peer group information besides the CEA, including regulatory authority websites, particularly those jurisdictions with PBR, utility company annual reports, etc.

I repeat what I said at the 2003 GRA that Hydro performance relative to an external peer group provides valuable insights to the Board and the stakeholder review process. The importance of the peer group information is not solely its use as an external benchmark in absolute terms, but also as a measure of relative changes in performance. For example, Hydro has been successful in reducing its controllable costs by almost 2% annually in real terms over the past five years. It would be interesting to see if comparable utilities have been more or less successful in controlling their costs as a means for gauging the relative success of Hydro's cost control programs. I was under the impression that Hydro agreed with the importance of tracking external peer group performance when it signed on to the mediation agreement. I note that Hydro indicates that its reliability improvement target was established on the basis of, among other things, its performance relative to available comparable utilities (see responses to CA 56 NLH).

Benchmarking performance against an external peer group of comparable utilities is a vital component of a utility's business process, highlighting the areas requiring improvement. It is also an important component of the regulatory process, providing valuable information to the stakeholder audit process.

4.4 Performance-Based Regulation (PBR)

As I have testified in the past, PBR has the potential to produce significant value to both utilities and consumers. PBR provides an incentive for utilities to perform at levels comparable to, and exceeding, their peers, so is consistent with Hydro's goal of operational excellence. Hydro expressed its support for considering PBR by signing the

Mediator's Report (Appendix H of the *Decision and Order of the Board No. P.U. 14 2004)* which states:

> *Parties request that the Board prepare or obtain a report on Performance Based Regulation (PBR) alternatives for Hydro and NP, with input solicited from all interested stakeholders prior to finalization of the Report, and opportunity for comment and discussion in considering the final Report.*

It is extremely difficult for the Board and the various stakeholders in this proceeding to conduct a proper audit of Hydro's costs. Stakeholders are at a significant disadvantage to the utility owing to manpower and resource limitations, and as stated by the Board's Chair at the 2003 GRA to Mr. Wells, Hydro's CEO at the time (see October 10, 2003 transcript, page 145, lines 6 to 12, and lines 20 to 25):

> *There's an asymmetry of information here that I think the focus in that sense has to be on performance measures and benchmarking, if indeed this is going to work at all, there has to be a reliance on that.*

> *I guess having said that, and I jotted down this morning when I was thinking about some of the questions that I might ask you, I jotted down "what gets measured gets done" and I think you subsequently said, "what gets measured gets managed".*

PBR levels the regulatory playing field by basing a utility's revenue requirement on performance measures and benchmarking while reducing the regulatory burden on the utility. It addresses elements of the current regulatory regime that are frustrating to both utilities and stakeholders, for example, the issue of Hydro's target 20% reliability improvement, and the proposed increase in 2007 test year controllable costs.

With regard to Hydro's 20% target reliability improvement, under a PBR mechanism, Hydro could do as much work and spend as much money to improve reliability as it desires under the price or revenue cap provided reliability remains above a minimum benchmark level. Hydro would be subject to far less external scrutiny of its reliability improvement program.

With regard to the proposed increase in Hydro's controllable costs, stakeholders have every right to be skeptical. The response to CA 27 NLH indicates that the real annual increase (increase minus inflation) in Hydro's controllable costs has averaged negative (-) 1.9 % since 2002, and that the forecast change in inflation for 2007 is merely 1.3%. Hydro is proposing a 5.4% increase in controllable costs for the 2007 test year, 4.1% over the forecast rate of inflation, or roughly 6% greater than average annual "real" cost increases in recent history. As this increase is proposed for the 2007 test year, it will be fixed until the next rate application. No doubt Hydro feels this cost increase is necessary, but one can understand why stakeholders would be skeptical when Hydro speaks of its commitment to operational excellence in providing least cost, reliable power to the consumers of the Province. A PBR mechanism that establishes revenues or costs on the basis of a pre-defined formula including performance measures and benchmarking would help to alleviate this skepticism.

I note that the comments of the Board Chair at the 2003 GRA are relevant regardless of whether PBR is adopted in this Province. In fact, his comments were made within the context of the current regulatory mechanism.

4.5 Summary Review of Hydro's Commitment to Operational Excellence

With these points in mind, I recommend the following as means for Hydro to achieve its goal of operational excellence:

- The Board direct Hydro to prepare and submit to the Board for stakeholder review and Board approval a detailed framework and schedule for undertaking a formal integrated resource plan;
- The Board direct Hydro to prepare a clear reliability policy or procedure identifying minimum reliability performance benchmarks upon which to evaluate and audit reliability expenditures. Hydro should submit the policy or procedure to the Board for stakeholder review and Board approval. Following Board approval, Hydro should re-submit for Board approval its reliability improvement plan consistent with the new policy along with a detailed cost estimate and schedule for implementation;
- The Board direct Hydro to initiate tracking and reporting of performance relating to the indicators requested in CA 2 NLH and CA 3 NLH and

canvass customers concerning the value they place on such performance; and

- The Board direct Hydro to initiate reporting of key performance indicators in Exhibit JRH-1 with performance externally benchmarked to a comparable peer group as Hydro agreed to do in the Mediation Report (Appendix H of the *Decision and Order of the Board No. P.U. 14 2004)*.

This concludes my Pre-filed Evidence.

Exhibit CDB-1

C. Douglas Bowman Background and Qualifications

Profession	*ENERGY CONSULTANT*
Nationality	Canadian Citizen U.S. Resident
Years of Experience	29
Education	M.S./1977/Electrical Engineering/State University of New York, Buffalo, NY B.S./1975/Electrical Engineering/State University of New York, Buffalo, NY

Key Qualifications

Mr. Bowman has 29 years of experience in the power industry both domestically and internationally. His primary areas of expertise include power sector restructuring and regulation, market design and electricity service costing, pricing and contracts. Mr. Bowman has played a leading role in numerous consulting projects in Canada, Australia, Central America, China, Colombia, Dutch Antilles, Egypt, Ghana, India, Indonesia, Macao SAR, Mexico, Mongolia, Pakistan, Russia, Serbia, South Korea, Taiwan, Thailand, The Philippines, United States and Vietnam.

Expert Testimony at Newfoundland and Labrador Hydro's Rates Submission.
Provided expert oral and written testimony and participated in mediation sessions on issues related to cost of service, rate design and regulation at Hydro's 2003 General Rate Proceeding.

Expert Testimony at Newfoundland Light & Power's Rates Submission.
Provided expert written testimony and participated in mediation/technical sessions on issues related to cost of service and rate design at Newfoundland Power's 2003 General Rate Application.

Expert Testimony at Newfoundland and Labrador Hydro's Rates Submission.
Provided expert oral and written testimony related to cost of service and rate design issues at Hydro's 2001 General Rate Proceeding.

Expert Testimony at Newfoundland Light & Power's Rates Submission.
Provided expert oral and written testimony related to cost of service and rate design issues at Newfoundland Power's 1996 General Rate Proceeding.

Expert Testimony at Nova Scotia Power's Rates Submission.
Provided expert oral and written testimony related to cost of service and rate design issues. Recommended and designed time-of-day rates for all customer classes and designed an alternative interruptible rate design for large industrial customers.

Expert Testimony at Nova Scotia Power's Rates Submission.
Provided expert oral and written testimony regarding an Industrial Expansion rate design. Recommended approval of rate with modifications and submitted two alternative rate designs for approval including a real-time surplus power rate and a time-of-day expansion rate.

Cost of Service and Cost Reducing Rate Design Study
On behalf of the Nova Scotia Utility and Review Board, reviewed Nova Scotia's cost of service study, and developed rate designs consistent with Nova Scotia Power's integrated resource plan for all customer classes. Report was filed with Board, and reviewed as part of hearing on utility's subsequent rate submission.

Economic Policy Reform and Competitiveness Project – Mongolia
Developed incentive based power purchase agreement for sales of generating company capacity and energy to the transmission company. Currently developing a performance-based regulatory mechanism for electricity distribution companies.

Competitive Electricity Market Design – Taiwan
Developed competitive market design for electricity sector in Taiwan. Drafted complete set of market governance documents including Market Rules and Grid Code. Managed market modeling component of project which simulated market operation under wide range of scenarios.

Alberta RTO Evaluation Project
The objective of the Alberta Regional Transmission Organization (RTO) Evaluation Project was to determine a business relationship with RTO West that will ensure Alberta's electricity needs are met by a competitive market. The project participants included the Alberta Department of Energy, ESBI Alberta Limited, and the Power Pool of Alberta. KEMA Consulting developed supporting information and delivered a report to assist Alberta with formulation of a strategy relating to a preferred business relationship with RTO West.

Detailed Market Design and Market Rules Development, Western Australia
Served as project manager providing advice to the Government of Western Australia with regard to detailed market design, market rules development, and market power mitigation. Assisted with the stakeholder process, drafted position papers on various design topics, drafted market rules consistent with a bilateral contracts market, and designed a market power mitigation program.

Market Assessment of Generating Company in Korea
Provided advisory services to a client interested in submitting a bid for the purchase of a large generating company in Korea. Served as Project Manager for the market valuation component of the project. Revenues for the generating company were forecast using market simulation software both in the early years of the competitive market when it would be dominated by vesting contracts, and in later years when the market would become fully competitive with an independent system operator administering a power pool operating alongside a financial bilateral contracts market.

Market Power Mitigation Strategy for Generating Company in Korea
Provided advisory services to a large generating company in Korea relating to a market power mitigation strategy. Served as project manager. The project included market simulation to determine if the generating company would have market power in the new competitive market, and if so, if its market power were any greater than other generating companies participating in the market.

Expert Testimony in Kansas Civil Case Concerning IPP Development
Provided expert testimony concerning the independent power producer (IPP) programs in India and Colombia. The testimony related to the difficulties and hurdles that must be overcome in order to successfully develop an independent power project in a developing country.

Advisory Services on Electricity Market Design in Serbia
Developed a high-level, phased design for the internal Serbian electricity market consistent with the EU Directive. Project included three specific tasks: initial mobilization, organization of workshops, and report and presentation. The project intent was to provide institutional support to the Ministry of Mining and Energy to facilitate the phased development of the internal electricity market with competitive bilateral contracts taking into account Serbian Energy Policy, the draft Energy Law, European Union requirements and the Athens Memorandum 2002.

Development of Market Rules for Competitive Power Market in Indonesia
Project Manager responsible for leading a team of experts in the design of market rules for a competitive power market in Java-Bali, Indonesia. Under Phase 1 of the project, market rules were developed for a single-buyer market that will serve until reforms are in place to allow progression to a fully competitive, multi-buyer market structure. The market rules for the multi-buyer market structure were developed under Phase 2 of the project, and included market simulation, and development of a transition plan for moving from the single-buyer market structure to the multi-buyer market structure over time.

Expert Testimony in California Civil Case Concerning Breach of Contract.
Provided expert testimony concerning the value of a company based on revenues generated less costs to manage and operate the business. Revenues were derived from a contract for energy services covering steam and electricity sales to an industrial client and its power purchase agreement covering electricity sales to a utility. Costs to manage and operate the business included administrative costs, the cost of a lease and the cost of an operation and maintenance contract with an O&M provider.

Advice on IPP's Power Delivery Contract. Provided expert advice and written testimony on the value of an IPP's power delivery contract before the New Jersey Public Utilities Board.

Workshop on Transmission Planning in a Competitive Power Market
Conducted workshop on transmission planning for proposed RTO West in Portland, Oregon. Workshop covered transmission planning responsibilities of Regional Transmission Organizations under FERC Order No. 2000 and experience with domestic independent system operators and international transmission organizations. Reliance on market mechanisms for transmission expansion was emphasized at workshop.

Workshop on Transmission Pricing in a Competitive Power Market
Conducted workshop on transmission pricing for proposed RTO West in Portland, Oregon. Workshop covered transmission pricing in Regional Transmission Organizations under FERC Order 2000 and experience with domestic Independent System Operators and international transmission organizations. Workshop addressed transmission services such as network, connection, import, export, and point-to-point service, and cost recovery such as postage stamp, zonal and nodal pricing.

Advisory Services on Electricity Supply Industry Reform, EGAT, Thailand: Project Manager leading critical analysis of reform options and identification of those characteristics that have been implemented elsewhere and are directly applicable to Thailand, culminating in a Thailand-specific plan for power sector reform and power sector privatization.

Development of Terms and Conditions for Transmission Tariff
Assisted Ontario Hydro Services Company with development of terms and conditions for its new transmission tariff. The terms and conditions were filed with the regulatory authority as part of the utility's application for approval of the new tariff. Also assisted with preparation of responses to various discovery questions related to the tariff.

International Survey of Transmission Rates and Services
Conducted a survey of transmission rates and services provided in various domestic and international jurisdictions. Survey conducted in support of submission by Ontario Hydro Services Company to Ontario Energy Board on its new transmission tariff. Survey topics included: services offered such as network, point-to-point, connection, import and export service; cost recovery such as postage stamp, zonal and nodal pricing; treatment of generation; and transmission planning.

Restructuring in the Philippines: For JBIC-funded project in the Philippines, worked with a team from Chubu Electric. Responsible for evaluating impact of market reform plan on transmission company operations, pricing, and regulation, and comparison of Philippine environment to Thailand, Indonesia, Malaysia, etc. Conducted analysis of impact of introduction of new electricity law, market rules and Grid Code, recommending appropriate regulation, and strategy for benchmarking of performance.

Implementation of Power Sector Restructuring Plan for Shanghai Municipal Electric Power Company.
Managed the tariff and technical components of the study that included development of a generation purchase tariff to promote economic dispatch, a review of operations, dispatch and unit scheduling procedures, and an evaluation of the potential role for a Grid Code to promote development, maintenance and operation of an efficient, coordinated and economical power system.

Feasibility Study of Merchant Co-generation Project.
Participated with a team of consultants on a feasibility study for development of a merchant co-generation facility to sell power into the wholesale market and steam to the industrial plant. Directed market studies including analyses of forecasts for electricity demand, new generating plant construction, generation costs, market bid strategies, fuel costs, utility avoided costs, etc.

Advice to Mid-west Cooperative Concerning Role in Deregulated Power Market.
Provided advice to a mid-west cooperative on positioning itself for a deregulated power market. Advice included the cooperative's future power purchasing strategy, transmission and distribution construction and operations and maintenance strategy and how it should position itself to compete in the future deregulated power market.

Advice to Cooperatives Concerning Power Purchase Strategy and Transfer Pricing Mechanism.
Advised a group of cooperatives concerning implementation of a transfer pricing methodology that would enable each member to choose the supplier of its choice while leaving the remaining members harmless. The intent was to ensure that each member paid its fair share of the costs associated with the group's power purchase commitments.

Expert Testimony at Various Rate Hearings in Ontario.
Participated in annual rate cases in Ontario, Canada. Extent and content of input varied with position at Ontario Hydro at time of rate hearing.

Experience

Independent Consultant, Warrenton, VA 2005 to Present

Nexant, Inc., Washington, DC 2004
Executive Consultant

KEMA Consulting, Fairfax, VA 1999 to 2004
Executive Consultant

Pace Global Energy Services, Fairfax, VA 1998 to 1999
Director, Power Services

International Resources Group, Ltd. (IRG), Washington, DC 1995 to 1998
Senior Manager, Energy Group

CSA Energy Consultants, Arlington, VA 1994 to 1995
Vice President (1995); Senior Manager, Power Supply Analysis (1994)

Ontario Hydro, Toronto, Ontario, Canada 1977 to 1993
Industrial Service Advisor, Field Support Services Department, 1992-1993

Senior Rate Economist, Rate Structures Department, 1990-1992

Planning Engineer, Demand/Supply Integration, System Planning Division, 1988-1990

Senior Engineer, Resource Utilization, Power System Operations Division, 1987-1988

Planning Engineer, BES-Resources Planning, System Planning Division, 1981-1987

Assistant Planning Engineer, Transmission System Planning Department, 1979-1981

Engineer-in-Training, 1977-1979

Professional Affiliations

Professional Engineers of Ontario; Institute of Electrical and Electronic Engineers

Publications

1. Paper entitled *PBR – A Window of Opportunity for Transmission Owners* published in the July/August 2000 edition of Utility Automation
2. Paper (joint authorship with Margaret McKay) entitled *PBR Delivers Maximum Benefits* published in the April 2001 edition of Electric Light & Power
3. Conducted workshop on *Design of Performance-Based Regulatory Mechanisms* at Power Delivery Reliability Conference in Denver sponsored by KEMA Consulting in June/2000
4. Presented paper on *Performance-Based Regulation – Experience and Emerging Trends* at Xenergy Disco 2001 Event in San Diego in February 2001
5. Presented paper on *Performance-Based Ratemaking – Recent International Experience and Emerging Trends* at Performance-Based Ratemaking Conference in Denver co-sponsored by KEMA Consulting on November 9/10, 2000. In addition, served as conference chairperson, and led Panel Sessions
6. Presented paper on *Performance-Based Regulation for Regional Transmission Organizations – Industry Trends* at Regional Transmission Organizations conference in Denver co-sponsored by KEMA Consulting in November 1999
7. Conducted workshop on Transmission Pricing under Open Access at Asia PowerGen Conference in Bangkok in September 2000

Exhibit CDB-2

Delaware Public Service Commission
Order No. 7002

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF DELAWARE

IN THE MATTER OF THE CONSIDERATION OF RULES, STANDARDS, AND INDICES TO ENSURE RELIABLE ELECTRICAL SERVICE BY ELECTRIC DISTRIBUTION COMPANIES (OPENED SEPTEMBER 26, 2000; REOPENED OCTOBER 11, 2005)	)	PSC REGULATION DOCKET NO. 50

ORDER NO. 7002

AND NOW, to-wit, this 8th day of August, 2006;

WHEREAS, in 2003, the Commission originally adopted "Electric Service Reliability and Quality Standards" to provide interim benchmark standards related to the reliability of electric service provided by the two Commission-jurisdictional electric distribution utilities ("EDUs"); and

WHEREAS, in PSC Order No. 6745 (Oct. 11, 2005), the Commission proposed and then published (9 Del. Reg. 756-768 (Nov., 2005)) final "Electric Service Reliability and Quality Standards" to measure and govern the reliability of services provided by EDUs as well as to acquire information from in-State generation facilities; and

WHEREAS, several interested and affected entities voiced objections, or offered comments, concerning various provisions in the proposed final Standards and thereafter renewed those objections during the duly-noticed public comment session hearing held by the designated Hearing Examiner; and

WHEREAS, after the public comment session, several of the entities filing comments and Staff entered into a settlement document that endorsed a revised form for the final Standards; and

WHEREAS, the designated Hearing Examiner held a duly-noticed hearing on the settlement document and the revised form of final Standards, and submitted a Report, dated May 10, 2006, that recommended that the Commission adopt the settling entities' form of final Standards as the Commission's form of final Standards, superseding the Standards previously proposed and noticed in November of 2005; and

WHEREAS, on June 20, 2006, by PSC Order No. 6925, the Commission found, for the reasons set forth in the Hearing Examiner's Report, that the settling entities' revised form of Standards is appropriate and will further the Commission's goal of ensuring reliable electrical services by jurisdictional EDUs; and

WHEREAS, the Commission (in an abundance of caution) determined that the revised form of Standards made "substantive" changes from the Standards proposed in November of 2005 and therefore directed Staff to publish the revised version of the proposed final Standards in the *Delaware Register* for further comment, as required by 29 Del. C. § 10118(c) (<u>see</u> 10 Del. Reg. 74-87 & 199-200 (July 1, 2006); and

WHEREAS, the Commission received no new comments relating to these proposed final Standards in response to this further notice; and

WHEREAS, the Commission held a duly-noticed public hearing on August 8, 2006, to consider final adoption of the Standards (as previously recommended by the Hearing Examiner) and no person or entity opposed adoption of the revised form of final Standards; and

WHEREAS, the Commission has the authority to adopt the final regulations under 26 Del. C. §§ 209, 1002, 1008, and 1019;

Now, therefore, **IT IS ORDERED:**

1. The Commission hereby adopts and incorporates by reference, in its entirety, its prior Order No. 6925 (June 20, 2006).

2. That the Commission hereby adopts and approves the proposed "Electric Service Reliability and Quality Standards" set forth as Exhibit "A" to this Order (being the same Standards that were approved and published pursuant to Order No. 6925). The Secretary of the Commission shall transmit to the Registrar of Regulations for publication in the *Delaware Register*, the exact text of the final Standards attached hereto as Exhibit "A" for publication in the September 1, 2006 issue of the *Delaware Register of Regulations*.

3. The effective date of this Order shall be the later of September 10, 2006, or ten days after the date of publication in the *Delaware Register of Regulations*.

4. The Commission reserves the jurisdiction and authority to enter such further Orders in this matter as may be deemed necessary or proper.

BY ORDER OF THE COMMISSION:

/s/ Arnetta McRae
Chair

/s/ Joann T. Conaway
Commissioner

/s/ Jaymes B. Lester
Commissioner

/s/ Dallas Winslow
Commissioner

____
Commissioner

ATTEST:

/s/ Karen J. Nickerson
Secretary

E X H I B I T "A"

STATE OF DELAWARE
Delaware Public Service Commission

Electric Service Reliability and Quality Standards

Contents

1.0 Purpose and Scope

1.1. Reliable electric service is of great importance to the Delaware Public Service Commission ("Commission"), because it is an essential service to the citizens of Delaware. This regulation, in support of 26 Del. C., § 1002, sets forth reliability standards and reporting requirements needed to assure the continued reliability and quality of electric service being delivered to Delaware customers and is applicable to all Delaware Electric Distribution Companies ("EDCs") and Delaware Generation Companies.

1.2. Nothing in this regulation relieves any utility or generation company from compliance with any requirement set forth under any other regulation, statute or order. This regulation is in addition to those required under PSC Docket No. 58, Order No. 103, Regulations Governing Service Supplied by Electrical Utilities.

1.3. Compliance with this regulation is a minimum standard. Compliance does not create a presumption of safe, adequate and proper service. Each EDC needs to exercise their professional judgment based on their systems and service territories. Nothing in this regulation relieves any utility from the requirement to furnish safe, adequate and proper service and to keep and maintain its property and equipment in such condition as to enable it to do so. (26 **Del. C**., § 209)

1.4. Each EDC shall maintain the reliability of its distribution services and shall implement procedures to require all electric suppliers to deliver energy to the EDC at locations and in amounts which are adequate to meet each electric supplier's obligations to its customers. (26 **Del. C**., § 1008)

1.5. Each generation company operating in the state is required to provide the Commission with an annual assessment of their electric supply reliability as specified in Section 10.

1.6. This regulation requires the maintenance and retention of reliability data and the reporting of reliability objectives, planned actions and projects, programs, load studies and actual resulting performance on an annual basis, including major events as specified in section 11.

1.7. EDCs are responsible for maintaining the reliability of electric service to all their customers in the state of Delaware. Pursuant to this requirement, EDCs may be subject to penalties as described in Section 13 or 26 **Del. C**., §1019.

1.8. EDCs are required to explore the use of proven state of the art technology, to provide cost effective electric service reliability improvements.

1.9. This Electric Service Reliability and Quality regulation shall be effective through 2012 and may be reviewed, revised or extended as necessary to ensure the maintenance of electric reliability and quality service in Delaware.

2.0 Definitions

The following words and terms, as used in these regulations, shall have the following meanings, unless the context clearly indicates otherwise:

“Acceptable reliability level” is defined as the maximum acceptable limit of the System Average Interruption Duration Index (“SAIDI”), and the Constrained Hours of Operation as specified in Section 4.0

“ALM” means Active Load Management in accordance with Article 1, Schedule 5.2 of PJM’s Reliability Assurance Agreement (RAA).

“Availability” means the measure of time a generating unit, transmission line, or other facility is capable of providing service, whether or not it actually is in service.

“Beginning restoration” includes the essential or required analysis of an interruption, the dispatching of an individual or crew to an affected area, and their arrival at the work site to begin the restoration process (normally inclusive of dispatch and response times).

“Benchmark” means the standard service measure of SAIDI and Constrained Hours of Operation as set forth in this regulation.

“Capacity” means the rated continuous load-carrying ability, expressed in megawatts (“MW”) or megavolt-amperes (“MVA”) of generation, transmission, or other electrical equipment.

“Capacity Emergency Transfer Objective (‘CETO’)” means the amount of megawatt capacity that an area or sub area must be able to import during localized capacity emergency conditions such that the probability of loss of load due to insufficient tie capability is not greater than one day in 10 years.

“Capacity Emergency Transfer Limit (‘CETL’)” means the amount of megawatts that can actually be imported into the area or sub area during localized capacity emergency conditions.

“Constrained hours of operation” means the hours of electric system operation during which time there are limits, transfer constraints or contingencies on the PJM DPL Zone delivery system that require off-cost dispatch of generating facilities. Total constrained hours exclude offcost operations attributable to generation or transmission forced outages, generation or transmission related construction or any unrelated third party actions including generation retirements, provided mitigating projects are planned, permitted and constructed in a reasonable timeframe.

"Contingency" means the unexpected failure or outage of a system component, such as a generator, transmission line, circuit breaker, switch, or other electrical element. A contingency may also include multiple components, which are related by situations leading to simultaneous component outages.

"Corrective action" means the maintenance, repair, or replacement of an EDC's utility system components and structures to allow them to function at an acceptable level of reliability.

"Corrective maintenance" means the unplanned maintenance work required to restore delivery facilities to a normal operating condition that allows them to function at an acceptable level of reliability.

"Customer Average Interruption Duration Index ('CAIDI')" represents the average time in minutes required to restore service to those customers that experienced sustained interruptions during the reporting period. CAIDI is defined as follows:

$$\textbf{CAIDI} = \frac{\textbf{Sum of all Sustained Customer Interruption Durations per Reporting Period}}{\textbf{Total Number of Sustained Customer Interruptions per Reporting Period}}$$

"Customers Experiencing Long Interruption Durations$_8$ ('CELID$_8$')" **represents the total number of customers that have experienced a cumulative total of more than eight hours of outages.**

"Customers Experiencing Multiple Interruptions$_8$ ('CEMI$_8$')" **is an index that represents the total number of customers that have experienced nine or more interruptions in a single year reporting period.**

$$\text{CEMI}_8 = \frac{\text{Total number of customers that experienced more than eight (8) sustained interruptions}}{\text{Total number of customers served}}$$

"Delivery Facilities" means the EDC's physical plant used to provide electric energy to Delaware retail customers, normally inclusive of distribution and transmission facilities.

"Dispatch time" is the elapsed time between receipt of a customer call and the dispatch of a service resource to address the customer's issue as tracked by an Outage Management System.

"Distribution feeder" or "feeder" means a three-phase set of conductors emanating from a substation circuit breaker serving customers in a defined local distribution area. This includes three-phase, two-phase and single-phase branches that are normally isolated at all endpoints.

"Distribution facilities" means electric facilities located in Delaware that are owned by a public utility that operate at voltages of 34,500 volts or below and that are used to deliver electricity to customers, up through and including the point of physical connection with electric facilities owned by the customer.

"Electric Distribution Company" or "EDC" means a public utility owning and/or operating transmission and/or distribution facilities in this state.

"Electric distribution system" means that portion of an electric system, that delivers electric energy from transformation points on the transmission system to points of connection at the customers' premises.

"Electric service" means the supply, transmission, and distribution of electric energy as provided by an electric distribution company.

"Electric Supplier" means a person or entity certified by the Commission that sells electricity to retail electric customers utilizing the transmission and/or distribution facilities of a nonaffiliated electric utility, as further specified in 26 Del.C., §1001.
"Forced outage" means the removal from service availability of a generating unit, transmission line, or other facility for emergency reasons or a condition in which the equipment is unavailable due to unanticipated failure.[1]

"Forced outage rate" means the hours a generating unit, transmission line, or other facility is removed from service, divided by the sum of the hours it is removed from service plus the total number of hours the facility was connected to the electricity system expressed as a percent.[2]

Multiple momentary forced outages on the same transmission line in the span of a single minute shall be treated as a single forced outage with the duration of one minute. When

[1] North American Electric Reliability Council – "Glossary of Terms", August 1996
[2] North American Electric Reliability Council – "Glossary of Terms", August 1996

the operation of a transmission circuit is restored following a forced outage and the transmission line remains operational for a period exceeding one minute or more, followed by another forced outage, then these should be counted as two forced outages. Multiple forced outages occurring as a result of a single event should be handled as multiple forced outages only if subsequent operation of the transmission line between events exceeds one minute. Otherwise they shall be considered one continuous forced outage.[3]

"Generation company" means a private or publicly owned company that owns or leases, with right of ownership, plant, equipment and facilities in the state of Delaware, rated in excess of 25 MVA and capable of supplying electric energy to the transmission and/or distribution system.

"**Generation Working Group"** means a forum within which Generation companies can voluntarily provide to the Commission information related to the operation of their Generating Plants that would otherwise be required pursuant to these Regulations.

"Interruption" means the loss of electric service to one or more customers. It is the result of one or more component outages, depending on system configuration or other events. See "outage" and "major event." The types of interruption include momentary event, sustained and scheduled.

"Interruption, duration" means the period (measured in minutes) from the initiation of an interruption of electric service to a customer until such service has been restored to that customer. An interruption may require step restoration tracking to provide reliable index calculations.

[3] Draft CAISO Transmission Control Agreement, Appendix C, ISO Maintenance Standards

"Interruption, momentary event" means an interruption of electric service to one or more customers, of which the duration is less than or equal to 5 minutes. This definition includes all reclosing operations, which occur within five minutes of the first interruption. For example, if a recloser or breaker operates two, three, or four times and then holds within five minutes, the event shall be considered one momentary event interruption.

"Interruption, scheduled" means an interruption of electric service that results when one or more components are deliberately taken out of service at a selected time, usually for the purposes of preventative maintenance, repair or construction. Scheduled interruptions, where attempts have been made to notify customers in advance, shall not be included in SAIDI, SAIFI, CAIDI, or Forced Outage measures.

"Interruption, sustained" means an interruption of electric service to one or more customers that is not classified as a momentary event interruption and which is longer than five minutes in duration.

"Interrupting device" means a device, capable of being reclosed, whose purpose includes interrupting fault currents, isolating faulted components, disconnecting loads and restoring service. These devices can be manual, automatic, or motor operated. Examples include transmission and distribution breakers, line reclosers, motor operated switches, fuses or other devices.

"Major Event" means an event consistent with the I.E.E.E.1366, Guide For Electric Power Distribution Reliability Indices standard as approved and as may be revised. For purposes of this regulation, changes shall be considered to be in effect beginning January 1 of the first calendar year after the changed standard is adopted by the I.E.E.E. Major event interruptions shall be excluded from the EDC's SAIDI, SAIFI, CAIDI and Constrained Hours measurements for comparison to reliability benchmarks. Interruption data for major events shall be collected, and reported according to the reporting requirements outlined in Section 11.

"Mid Atlantic Area Council ('MAAC') or Reliability First Corporation "means a regional council of the North American Electric Reliability Council ("NERC"), or successor organization, that is responsible for Mid Atlantic operational policies and reliability planning standards applicable to PJM and local electric distribution company members.

"North American Electric Reliability Council ('NERC')" means the national organization responsible for operational policies and reliability planning standards applicable to national system operations and electric distribution companies, or their successor organizations.

"Outage" means the state of a component when it is not available to perform its intended function due to some event directly associated with that component. An outage may or may not cause an interruption of electric service to customers, depending on system configuration.

"Outage Management System ('OMS')" means a software operating system that provides database information to effectively manage service interruptions and minimize customer outage times.

"Pre-restructuring" refers to the five-year time frame prior to Delaware's adoption of 26 **Del. C**., Chapter 10, Electric Utility Restructuring Statute (1995-1999).

"PJM Interconnection, L.L.C. ('PJM')" means the Regional Transmission Organization or successor organization that is responsible for wholesale energy markets and the interstate transmission of energy throughout a multi-state operating area that includes Delaware.

"Power quality" means the characteristics of electric power received by the customer, with the exception of sustained interruptions and momentary event interruptions. Characteristics of electric power that detract from its quality include waveform irregularities and voltage variations—either prolonged or transient. Power quality problems shall include, but are not limited to, disturbances such as high or low voltage, voltage spikes or transients, flicker and voltage sags, surges and short-time overvoltages, as well as harmonics and noise.

"Preventive maintenance" means the planned maintenance, usually performed to preclude forced or unplanned outages, and which allows delivery facilities to continue functioning at an acceptable level of reliability.

"Reliability" means the degree of performance of the elements of the bulk electric system that results in electricity being delivered to customers within accepted standards and in the amount desired. Reliability may be measured by the frequency, duration, and magnitude of adverse effects on the electric supply. Electric system reliability can be addressed by considering two basic and functional aspects of the electric system – Adequacy and Security.

> Adequacy - The ability of the electric system to supply the aggregate electrical demand and energy requirements of customers at all times, taking into account scheduled and reasonably expected unscheduled outages of system elements.

Security - The ability of the electric system to withstand sudden disturbances such as electric short circuits or unanticipated loss of system elements.[4]

As applied to distribution facilities, reliability is further described as the degree to which safe, proper and adequate electric service is supplied to customers without interruption.

“Repair time” is the elapsed time from the arrival of the service resource at the identified problem site to the correction of the customer’s original concern as tracked by the OMS.

“Response time” is the elapsed time from dispatch of service resource to the arrival of the service resource at the identified problem site as tracked by the OMS.

“Step restoration” means the restoration of service to blocks of customers in an area until the entire area or circuit is restored.

“Sum of all Sustained Customer Interruption Durations” means the summation of the restoration time (in minutes) for each event times the number of interrupted customers for each step restoration of each interruption event during the reporting period.

“Supervisory Control And Data Acquisition (‘SCADA’)” is an electronic communication and control system that provides electrical system operating information and mechanisms to remotely control energy flows and equipment.

[4]NERC definition - NERC’s Reliability Assessment 2001–2010, dated October 16, 2001.

"System Average Interruption Duration Index ('SAIDI')" represents the average duration of sustained interruptions per customer. SAIDI is defined as:

$$\text{SAIDI} = \frac{\text{Sum of all Sustained Customer Interruption Durations per Reporting Period}}{\text{Total Number of Customers Served per Reporting Period}}$$

"System Average Interruption Frequency Index ('SAIFI')" represents the average frequency of sustained interruptions per customer during the reporting period. SAIFI is defined as:

$$\text{SAIFI} = \frac{\text{Total Number of Sustained Customer Interruptions per Reporting Period}}{\text{Total Number of Customers Served per Reporting Period}}$$

"Total Number of Sustained Customer Interruptions" means the sum of the number of interrupted customers for each interruption event during the reporting period. Customers who experienced multiple interruptions during the reporting period are counted for each interruption event the customer experienced during the reporting period.

"Total Number of Customers Served" means the number of customers provided with electric service by the distribution facility for which a reliability index is being calculated on the last day of the time period for which the reliability index is being calculated. This number should exclude all street lighting (dusk-to-dawn lighting, municipal street lighting, traffic lights) and sales to other electric utilities.

"Transmission facilities" means electric facilities located in Delaware and owned by a public utility that operate at voltages above 34,500 volts and that are used to transmit and deliver electricity to customers (including any customers taking electric service under interruptible rate schedules as of December 31, 1998) up through and including the point of physical connection with electric facilities owned by the customer.

3.0 Electric Service Reliability and Quality

3.1. Each EDC shall provide reliable electric service that is consistent with pre-restructuring service levels as identified in Section 4. and complies with 26 Del. C., § 1002.

3.2. Each EDC shall install, operate, and maintain its delivery facilities in conformity with the requirements of the National Electrical Safety Code and the operating policies and standards of NERC, MAAC and PJM, or their successor organizations.

3.3. Each EDC shall have targeted objectives, programs and/or procedures and forecast load studies, designed to help maintain the acceptable reliability level for its delivery facilities and, where appropriate, to improve performance.

3.4. Each EDC, in accordance with Section 9., shall submit to the Commission, on or before March 31 of each year, a Planning and Studies Report identifying its current year's annual objectives, planned actions and projects, programs, and forecast studies that serve to maintain reliability and quality of service at an acceptable reliability level.

3.5. Each EDC, in accordance with Section 10., shall submit to the Commission, on or before April 30 of each year, a Performance Report that assesses the achievement of the previous year's objectives, planned actions, projects and programs, and assesses the relative accuracy of forecast studies and previous years performance measures with respect to benchmarks.

3.6. Each generation company in accordance with Section 10. shall submit to the Commission on or before April 30 of each year, a Performance Report that evaluates their reliability of energy supply.

3.7. Each EDC shall ensure that distribution system generation interconnection requirements are consistent with the I.E.E.E. 1547 series, “Standard for Interconnecting Distributed Resources with Electric Power Systems, as currently approved and as may be revised.

3.8. Each EDC shall file and maintain with the Commission a copy of the technical requirements for distribution system generation interconnection.

4.0 Reliability and Quality Performance Benchmarks

4.1. The measurement of reliability and quality performance shall be based on annual SAIDI and Constrained Hours of Operation measures for each EDC. The SAIDI calculation shall include all Delaware customer outages, excluding major events, and shall be reported along with its SAIFI and CAIDI components, subdivided by its distribution, substation and transmission components. The Constrained Hours of Operations shall be based on peninsula (DPL Zone) transmission system contingency limitations that require the dispatch of off-cost generation, excluding generation or transmission forced outages, generation or transmission related construction or any unrelated third party actions.

4.2. Each EDC shall maintain their electric service reliability and quality performance measures within the benchmark standard of this Section 4, Paragraph.3. SAIDI and Constrained Hours of Operation performance shall be measured each calendar year. Annual SAIDI and Hours of Constrained Operation performance equal to or better than the acceptable reliability level meets the standard of this regulation. When performance does not meet the acceptable reliability level, further review and analysis are required. The EDC may be subject to penalties as defined in Section 13. and subsequent corrective actions may be required.

4.3. For the EDCs, the electric service reliability and quality performance benchmarks are established as follows:

4.3.1. The system SAIDI benchmark standard, which is based on pre-restructuring levels of performance and adjusted to reflect a 1.75 standard deviation of data variability and the transition to an OMS system shall be as follows:

4.3.1.1.Delaware Electric Cooperative SAIDI shall be 635 minutes per customer; and
4.3.1.2.Delmarva Power SAIDI shall be 295 minutes per customer.

4.3.2. Based on the PEPCO/Conectiv merger settlement, the Constrained Hours of Operation benchmark standard shall be 600 hours for each EDC.

4.4. Each EDC shall track and report its annual performance and three-year average performance against benchmark standards in accordance with Section 10.

4.5. Each EDC shall track and report its annual CAIDI, SAIFI, CEMI8 and CELID8 performance in accordance with Section 10.

5.0 Reliability and Quality Performance Objectives

5.1. Each EDC shall establish electric service reliability and quality performance objectives for the forthcoming year. Objectives shall include:

5.1.1. Anticipated performance measures designed to maintain reliable electric distribution service with a description of any planned actions to achieve target objectives;

5.1.2. Anticipated performance measures designed to maintain transmission circuits and power transformers with a description of any planned actions to achieve target objectives; and

5.1.3. Annual corrective, preventive and total maintenance program hours and costs anticipated on Delaware transmission circuits, distribution circuits and substation equipment.

5.2. Performance objective measures shall be established to support the maintenance of electric reliability performance. Performance objectives shall be representative of expected performance, taking into consideration anticipated new construction projects, power quality and maintenance programs, planned actions and any resource or time limitations.

6.0 Power Quality Program

6.1. Each EDC shall maintain a power quality program with clearly stated objectives and procedures designed to respond promptly to customer reports of power quality concerns.

6.2. Each EDC shall consider power quality concerns in the design, construction and maintenance of its transmission and distribution power delivery system components to mitigate, using reasonable measures, power quality disturbances that adversely affect customers' equipment.

6.3. Each EDC shall maintain records of customer power quality concerns and EDC response. These records shall be made available to the Commission Staff upon request with 30 days notice.

7.0 Inspection and Maintenance Program

7.1. Each EDC shall have an inspection and maintenance program designed to maintain delivery facilities performance at an acceptable reliability level. The program shall be based on industry codes, national electric industry practices, manufacturer's recommendations, sound engineering judgment and past experience.

7.2. As a maintenance minimum, each EDC shall inspect and maintain as necessary its power transformers, circuit breakers, substation capacitor banks, automatic 3-phase circuit switches and all 600 amp or larger manually operated, gang transmission circuit tie switches at least once every two (2) years.

7.3. As a maintenance minimum, each EDC shall inspect all right-of-way vegetation at least once every four (4) years and trim or maintain as necessary, according priorities to circuits that have had significant numbers of vegetation-related outages, while not unduly delaying the trimming of other circuits that inspections indicate currently need trimming. Vegetation management practices should be applied at least once every four (4) years except where growth or other assessments deem it unnecessary.

7.4. Each EDC shall maintain records of inspection and maintenance activities. Compliance with this requirement may be established by a showing of substantial compliance without regard for a single particular facility maintenance record. These records shall be made available to Commission Staff upon request with 30 days notice.

8.0 Delivery Facility Studies

8.1. Each EDC shall perform system load studies to identify and examine potential distribution circuit overloads, distribution substation and distribution substation supply circuit single contingencies and all transmission system single and double contingencies as specified by NERC, MAAC, Reliability First Corp. and PJM or successor requirements. Double contingency analysis should include supply service contingencies that may cause overloads or outages on the EDC’s system. Where NERC, MAAC, Reliability First Corp or PJM requirements are not applicable, the EDC shall at a minimum examine circuit and equipment overloads under normal and single contingency conditions at peak load, with and without ALM or other demand response mechanisms. The EDC shall identify all projects and/or corrective actions that are planned to mitigate reliability loading issues identified in the study.

8.2. Delivery facility planning studies will be performed annually under conditions specified by NERC, MAAC, Reliability First Corp. and PJM or their successor organization’s planning requirements, or as specified in 8.1. Studies shall identify required projects and/or planned corrective actions. For any study resulting in a thermal overload or an out-of-range voltage level, the study shall be performed again after the implementation of Active Load Management (ALM), system switching or reconfiguration.

8.3. Each EDC shall perform the electric delivery facility system planning studies as described herein in the fall of each year (year a) for the upcoming summer period (year b) and for the summer period two years later (year c). The planning studies will include all delivery facility enhancements planned to be in-service during the applicable summer peak and shall identify those delivery facilities that are anticipated to be overloaded during the peak demand period.

9.0 Planning and Studies Report

9.1. Prior to March 31 of each year, each EDC shall convene a stakeholder meeting offering opportunity for interested parties to discuss electric service reliability or quality concerns within Delaware. Such meeting shall be limited to discussion of publicly available information and at a minimum be open to generation companies, electric suppliers, municipals or other EDCs, PJM, state agencies and wholesale/retail consumers. Each EDC shall consider the resulting issues and include mitigation efforts in annual plans as appropriate.

9.2. By March 31 of each year, each EDC shall submit a reliability planning and studies report to the Commission for review. The report will identify current reliability objectives, load study results and planned actions, projects or programs designed to maintain the electric service reliability and quality of the delivery facilities.

9.3. The report shall include the following information:

9.3.1. Objective targets or goals in support of reliable electric service and descriptions of planned actions to achieve the objectives;

9.3.2. Delivery load study results as described in Section 8., to include at a minimum the information for both year b and year c as specified in Section 8., Paragraph 3.;

9.3.3. Description and estimated cost of capital projects planned to mitigate loading or contingent conditions identified in load studies or required to manage hours of congestion;

9.3.4. The EDC's power quality program and any amendments as required in Section 6.;

9.3.5. The EDC's inspection and maintenance program, any amendments as required in Section 7., and any specific actions aimed at reducing outage causes;

9.3.6. Copies of all recent delivery facility planning studies and network capability studies (including CETO and CETL results) performed for any delivery facilities owned by the utility; and

9.3.7. Summaries of any changes to reliability related requirements, standards and procedures at PJM, MAAC, First Reliability Corporation, NERC or the EDC.

9.3.8. Summary of any issues that resulted from the EDC stakeholder meeting and any projects or planning changes that may have been incorporated as a result of such meeting.

10.0 Annual Performance Report

10.1. By April 30 of each year, each EDC shall submit an annual Performance Report, summarizing the actual electric service reliability results. The report shall include the EDC's average three-year performance results, actual year-end performance measure results and an assessment of the results/effectiveness of the reliability objectives, planned actions and projects, programs, and load studies in achieving an acceptable reliability level.

10.2. Delivery facilities year-end performance measures, as established in Section 4., Paragraph 1. shall be reported as follows:

10.2.1. SAIDI, SAIFI, and CAIDI measures:

10.2.1.1. Current year and three-year average reflecting Delaware performance, classified by distribution, substation and transmission components; and

10.2.1.2. Current year for each feeder circuit providing service to Delaware customers, regardless of state origin.

10.2.2. Constrained hours of operation:

10.2.2.1. Current year and three-year average for the EDC's DPL Zone transmission system; and

10.2.2.2. Current year for the EDC's DPL Zone, classified by cause.

10.3. The Performance Report shall identify 2% of distribution feeders or 10 feeders, whichever is more, serving at least one Delaware customer, that are identified by the utility as having the poorest reliability. The EDC shall identify the method used to determine the feeders with poorest reliability and shall indicate any planned corrective actions to improve feeder performance and target dates for completion or explain why no action is required. The EDC shall ensure that feeders, identified as having the poorest reliability, shall not appear in any two consecutive Performance Reports without initiated corrective action.

10.4. The Performance Report shall include annual information that provides the Commission with the ability to assess the EDC's efforts to maintain reliable electric service to all customers in the state of Delaware. Such reporting shall include the following items:

10.4.1. Current year expenditures, labor resource hours, and progress measures for each capital and/or maintenance program designed to support the maintenance of reliable electric service, to include:

10.4.1.1. Transmission vegetation maintenance;

10.4.1.2. Transmission maintenance, excluding vegetation, by total, preventive, and corrective categories;

10.4.1.3. Transmission capital infrastructure improvements;

10.4.1.4. Distribution vegetation maintenance;

10.4.1.5. Distribution maintenance, excluding vegetation, by total, preventive and corrective categories;
10.4.1.6. Distribution capital infrastructure improvements;
10.4.1.7. Transmission and Distribution progress per Section 7., Paragraph 2. and 3.; and
10.4.1.8. Any related process, practice or material improvements.

10.4.2. Current year OMS data to include:

10.4.2.1. Number of outages by outage type;
10.4.2.2. Number of outages by outage cause;
10.4.2.3. Total number of customers at year end;
10.4.2.4. Total number of customers that experienced an outage; and
10.4.2.5. Total customer minutes of outage time.

10.4.3. Current year CELID8 and CEMI8 results, exclusive of major events, including any efforts being made to reduce the occurrences of multiple outages or long duration outages.

10.4.4. Current year customer satisfaction or other measures the EDC believes are indicative of reliability performance.

10.5. The Performance Report shall include a summary of each major event for which data was excluded, and an assessment of the measurable impact on reported performance measures.

10.6. In the event that an EDC’s reliability performance measure does not meet an acceptable reliability level for the calendar year, the Performance Report shall include the following:

10.6.1. For not meeting SAIDI, an analysis of the customer service interruption causes for all delivery facilities by dispatch, response and repair times that significantly contributed to not meeting the benchmark;

10.6.2. For not meeting Constrained Hours of Operation, an analysis of significant constraints by cause;

10.6.3. A description of any corrective actions that are planned by the EDC and the target dates by which the corrective action shall be completed; and

10.6.4. If no corrective actions are planned, an explanation shall be provided.

10.7. The Performance Report shall include copies of current procedures identifying methods the EDC uses to ensure the electric supplier delivery of energy to the EDC at locations and in amounts which are adequate to meet each electric supplier's obligation to its customers.

10.8. The Performance Report shall include certification by an officer of the EDC of the data and analysis and that necessary projects, maintenance programs and other actions are being performed and adequately funded by the Company as addressed in its annual plans.

10.9. Unless a generation company participates in the Generation Working Group, each generation company shall submit by April 30 of each year an annual Reliability Performance Report. The performance report shall include the individual unit and average station forced outage rates and any anticipated changes that may impact the future adequacy of supply. Each generation company shall also provide the Commission with at least a one-year advanced notification of any planned unit retirements, planned re-powerings or planned long-term unit de-ratings.

10.9.1. The performance report required by Section 10.9 shall include the individual unit and average station forced outage rates and any anticipated changes that may impact the future adequacy of supply.

10.9.2. Each generation company not a member of a Generation Working Group shall also provide the Commission with at least a one-year advanced notification of any planned unit retirements, planned re-powerings or planned long-term unit de-ratings.

10.10. In lieu of submission of an annual Reliability Performance and one-year advanced notification, as required in Section 10.9, Generation companies may voluntarily participate in a Generation Working Group.

10.10.1. The Commission shall designate one member of the Commission Staff to chair the Working Group. Such individual shall be referred to as the "Commission Staff Member."

10.10.2. Meetings of the Generator Working Group shall be no less frequently than semi-annually, and shall be scheduled by the Commission Staff Member.

10.10.3. The purpose of the semi-annual meetings will be for the Commission Staff Member and the participating Generation company or companies, as the case may be, to agree upon the specific parameters of generation information to be provided by member Generation companies to the Commission and how and when such information should be presented to the Commission. The specific parameters and presentation of information need not be identical for Generation Company, as agreed by the Generator Working Group.

10.10.4. In the event of a disagreement between the Commission Staff Member and a Generation company, the Generator Working Group will attempt to resolve the disagreement by consensus. If consensus cannot be achieved in a reasonable time, the Generator Working Group or any member may request a determination by the Commission of the issue.

10.10.5. To allow Generation companies to participate openly without disclosing commercially-sensitive information to each other, the semi-annual Working Group meetings may be supplemented with meetings between the Commission Staff Member and individual Generation companies. Such individual meetings may be requested, on an as needed basis, by the Commission Staff Member or by a Generation company.

10.10.6. The Generation company or companies, as the case may be, shall use its or their best efforts to provide the requested information within an agreed-upon period of time.

10.10.7. The Commission and each member of the Generator Working Group shall implement all steps necessary to protect the confidentiality of commercially sensitive information provided by the Generation company or companies, as the case may be.

10.10.8. Each member of the Generator Working Group reserves the right to not provide information of a commercially-sensitive nature to all or some of the members of the Generator Working Group unless and until it obtains legally sufficient protection against non-disclosure of such information, and each such member shall take reasonable steps to procure such legally sufficient protection, to the extent these Rules do not constitute such protection.

10.10.9. Any Generation company participating in the Generator Working Group may withdraw at any time.

11.0 Major Event Report

11.1. Each EDC shall notify the Commission of major events as soon as practical, but not more than 36 hours after the onset of a major event. Initial notification is required when more than 10% of an EDC's customers experience a sustained outage during a 24 hour period; however, I.E.E.E. 1366 standard shall apply to all performance calculations.

11.2. Each EDC is expected to restore service to customers as quickly and safely as permitted by major event conditions. The EDC's restoration effort may be subject to review, subsequent corrective actions and penalties as permitted by 26 Del. C. § 1019.

11.3. The EDC shall, within 15 business days after the end of a major event, submit a written report to the Commission, which shall include the following:

11.3.1. The date and time when the EDC's major event control center opened and closed;

11.3.2. The total number of customers out-of-service over the course of the major event in six hour increments;

11.3.3. The date and time when 75 %, 95% and 100% of customers affected by a major event were restored;

11.3.4. The total number of trouble assignments repaired, by facility classification (poles, miles of wire, transformers);

11.3.5. The time at which the mutual aid and non-company contractor crews were requested, arrived for duty and were released, and the mutual aid and non-contractor response(s) to the request(s) for assistance; and

11.3.6. A timeline profile in six-hour increments of the number of company line crews, mutual aid crews, non-company contractor line and tree crews working on restoration activities during the duration of the major event, summarized by total number of line, bucket, trouble, and tree types.

12.0 Prompt Restoration of Outages

12.1. Each EDC shall strive to restore service as quickly and as safely as possible at all times EDCs shall begin the restoration of service to an affected service area within two hours of notification by two or more customers of any loss of electric service. In situations where it is not practical to respond within two hours to a reported interruption (safety reasons, inaccessibility, multiple simultaneous interruptions, storms or other system emergencies), the EDC shall respond as soon as the situation permits.

12.2. Each EDC shall monitor dispatch, response and repair times for customer outages. In the event that average annual dispatch, response or repair performance times exceed the EDC’s expected levels for the calendar year, the EDC shall include the following in its annual performance report.

12.2.1. An analysis of the factors which caused the unexpected performance; and

12.2.2. A description of any corrective actions planned by the EDC to meet expected performance levels.

12.3. Each EDC shall have outage response procedures that place the highest priority on responding to emergency situations for which prompt restoration is essential to public safety. These procedures should include recognition of priority requests that may come from police, fire, rescue, authorized emergency service providers or public facility operators.

13.0 Penalties and Other Remedies

13.1. Private or investor owned utilities and cooperatives, operating in Delaware under the regulation of the Commission, are subject to penalties and other remedial actions in accordance with 26 Del.C., § 205(a), § 217, and § 1019. The Commission shall be responsible for assessing any penalty under this section, consistent with Delaware law. In determining if there should be a penalty for violation of a reporting requirement or benchmark standard and, if so, what the penalty amount should be, the Commission shall consider the nature, circumstances, extent and gravity of the violation including the degree of the EDC's culpability and history of prior violations and any good faith effort on the part of the EDC in attempting to achieve compliance. Such penalty shall not exceed $5,000 for each violation, with the overall penalty not to exceed an amount reasonable and appropriate for the violation (maximum of $600,000 per year per reporting or standard violation). Each day of noncompliance shall be treated as a separate violation. In the case of an electric cooperative, in violation of a reporting requirement or benchmark standard, the Commission shall not assess any monetary penalty that would adversely impact the financial stability of such an entity and any monetary penalty that is assessed against an electric cooperative shall not exceed $1,000 for each violation, which each day of noncompliance shall be treated as a separate violation (maximum of $60,000 per year per reporting or standard violation). Nothing in this section relieves any private or investor owned utility or cooperative from compliance or penalties, that may be assessed due to non-compliance with any requirement set forth under any other regulation, statute or order.

13.2. An EDC shall be considered in violation of the SAIDI or Constrained Hours of Operation performance benchmark standard when the annual year-end cumulative measure exceeds the benchmark standard. The term of the violation shall extend for the period of time during which the performance measure exceeded the benchmark standard.

13.3. Upon failure of any EDC to meet performance benchmark standards, the EDC shall report monthly, or over such other period of time that the Commission shall establish by order, the latest performance indices, until such time as performance meets the acceptable reliability level.

13.4. Each EDC not meeting performance benchmark standards as required by Section 4., shall inform its customers, in writing, of the results and plans to improve electric service reliability and quality by July 1 of the year following any year in which its performance does not meet an acceptable reliability level.

13.5. Each violation of any reporting rule or performance standard of this regulation shall constitute a single, separate and distinct violation for that particular day. Each day during which a violation continues shall constitute an additional, separate and distinct violation. Provided, however, that a violation of a performance measure shall not be deemed to be a violation per customer, whether affected or otherwise, but shall constitute a single Delaware-wide violation for the day.

13.6. In a proceeding to determine penalties or other remedial measures for any violation, but particularly with respect to the Constrained Hours of Operation, the Commission should consider the extent to which the measure or reporting requirement did not meet the established standard and the extent to which the EDC may have implemented cost-effective efforts to comply with the requirement.

13.7. Penalty assessments are payable as provided by Delaware statute.

14.0 Outage and Control Systems

14.1. Each EDC shall implement and maintain an Outage Management System (OMS) and a Supervisory Control and Data Acquisition System (SCADA) as described in this section by January 1, 2007.

14.2. The OMS, at a minimum, shall consist of an outage assessment software program, integrated with a geographic information system that permits an EDC to effectively manage outage events and restore customer service in a timely manner.

14.3. The OMS should permit the EDC to:

14.3.1. Group customers who are out of service to the most probable interrupting device that operated;

14.3.2. Associate customers with distribution facilities;

14.3.3. Generate street maps indicating EDC outage locations;

14.3.4. Improve the management of resources during a storm;

14.3.5. Improve the accuracy of identifying the number of customers without electric service;

14.3.6. Improve the ability to estimate expected restoration times;

14.3.7. Accurately identify the number and when customers were restored; and

14.3.8. Effectively support the dispatch of crews and/or service personnel.

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

14.4.1. Monitor and record critical system load data and major equipment status;

14.4.2. Provide remote operational control over major equipment; and

14.4.3. Incorporate generally accepted utility industry safety and security standards.

15.0 Reporting Specifications and Implementation

15.1. Planning and Studies Reports, Performance Reports and Major Event Reports provided under this regulation are subject to annual review and audit by the Commission. Each EDC and generation company must maintain sufficient records to permit a review and confirmation of material contained in all required reports.

15.2. Reports shall be submitted as an original and 5 paper copies with one additional copy submitted electronically to the Secretary, Delaware Public Service Commission, with certification of authenticity by an officer of the corporation. The electronic copy may be posted on the Delaware Public Service Commission's Internet website.

15.3. Each EDC or generation company may request that information, required under this regulation, be classified as confidential, proprietary and/or privileged material. The requesting party must attest that such information is not subject to inspection by the public or other parties without execution of an appropriate proprietary agreement. Each party requesting such treatment of information is also obligated to file one (1) additional electronic and paper copy of the information, excluding the confidential or proprietary information. The Commission, in accordance with Rule 11, Rules of Practice and Procedure of the Delaware Public Service Commission, effective May 10, 1999, will treat such information as “confidential, not for public release” upon receipt of a properly filed request. Any dispute over the confidential treatment of information shall be resolved by the Commission, designated Presiding Officer or Hearing Examiner.

15.4 This regulation replaces the Interim Regulation and is effective 10 days after publication in the Delaware Register; however, for the initial 2006 year, Planning and Studies reports are due March 31, 2006; Performance reports are due April 30, 2006, and compliance shall be based upon, in all respects, the standards and requirements of the Interim Regulations. Thereafter, and beginning January 1, 2007, EDC compliance shall be based upon the standards and requirements of these revised regulations.

Exhibit CDB-3

EPRI Solutions Multi-Client Study Prospectus

Technical and Business Strategies to Enhance Power Quality and Reliability

Investing in the 21st Century Distribution System

Technical and Business Strategies to Enhance Power Quality and Reliability

How can your utility work effectively with regulators to develop the optimal investment strategies to improve reliability and service quality?

Electric distribution companies are facing a "perfect storm." Rates in many jurisdictions have been frozen for several years. Assets are aging to a point such that increasing failure rates are inevitable. A maturing workforce is resulting in a loss of experienced distribution personnel and a need for proactive hiring and training. Despite these challenges, customers are demanding higher-quality service and regulatory agencies are increasingly focused on improving power reliability. How can distribution companies work effectively with their regulators to achieve the optimal long-term results?

For one distribution company in the Northeast U.S., the strategy was to seek approval for a $1 billion investment to improve customer power quality and reliability with a clear message to their regulators: *"Reliability and service can either **improve** with rate relief or **degrade** without it."* Another utility in California made a compelling regulatory case to replace aged assets—rather than wait for those assets to fail—based on a combination of approaches including run to failure, age-based replacement, and strategic replacement.

Why is This Study Important Now?

Reliability and quality of service are becoming more critical factors in the regulation of distribution companies. More state regulators are requiring utilities to report reliability levels, and many are establishing performance benchmarks. It is critical for regulators to recognize the direct relationships between system reliability and investment in the distribution infrastructure. Each distribution company is responsible for understanding this relationship and making the information available to regulators as part of rate case filings and other information exchanges. Then regulators can make informed decisions when setting system performance expectations and allow appropriate investments to achieve these performance levels.

Investment requirements to achieve improved reliability and power quality may be one of the most important aspects of many rate case filings. Most regulatory filings today focus mainly on the distribution portion of the utility and take a new approach compared to historic rate case filings by vertically integrated electric utilities. Stranded generation assets, major transmission projects, and other financial issues were previously the focus of rate relief requests. A new set of issues has moved to the forefront, including distribution reliability, power quality, customer service, and asset management strategies.

This new EPRI Solutions multiclient study will provide a detailed technical and business analysis of **the relationship between investment levels in distribution system enhancement and the expected impacts on reliability and quality**. This analysis, including examples of successful applications, will help participants work with regulators to identify the best investment strategies to maintain or improve reliability and quality of service.

Study Approach

This cooperative multiclient study will provide data and analysis techniques developed by EPRI Solutions to help utilities evaluate and document the relationship between system investment and improvements in quality and reliability. This effort will take advantage of three sources: 1) projects evaluating the effect of distribution system design and operation on quality and reliability levels, 2) work on the impacts of investments in distribution automation technologies, and 3) statistical evaluations of expected reliability and quality as a function of distribution system and environmental characteristics.

In addition, we will review publicly available documents filed by utilities around the world related to quality, reliability, customer service, and asset management strategies.

EPRI Solutions staff will focus on recently filed documents (after 2000) that feature **aging asset replacement** and **service quality and reliability improvement**. EPRI Solutions' distribution engineering experts (Tom Short, author of the *Distribution Engineering Handbook*, and Roger Dugan, an IEEE Fellow and IEEE's Outstanding Distribution Engineer of 2005) will provide in-depth analysis of the technical issues in these filings. Our market intelligence specialists will synthesize the study's findings into actionable strategies for distribution utilities that may submit plans for infrastructure investments in future years.

Key Issues to be Addressed

- How can investment in infrastructure, equipment replacement, and new technologies affect the quality and reliability of distribution systems?
- Which methodologies can be employed to characterize and document the relationship between reliability and system investment for planning purposes?
- Which strategies have utilities used in regulatory filings to document the required investment for replacing aging infrastructure and implementing new technology to improve power quality and reliability?
- Which strategies have utilities and regulators agreed are the most effective for addressing reliability and quality improvement needs?
- Which specific types of projects and initiatives have been proposed—and approved?
  - Capital projects
  - Operations and maintenance projects
  - Technology-based initiatives
  - Reliability initiatives
- What role, if any, have performance guarantees and/or penalties played in gaining rate relief, and how have these been established?

Study sponsors will receive information about the various approaches to determine costs associated with improving reliability and quality as well as the best methods to document these costs for discussions with regulators. This information will include insights into **which strategies have worked and why**. The study's findings will help distribution companies better negotiate these impending challenges and develop an effective strategy for moving their energy delivery systems into the 21st century.

Deliverables

EPRI Solutions is structuring this work as a multiclient project to provide high leverage to participants, while offering significant opportunities for customization.

We will build on our historical research in this area with new research during the first quarter of 2006, and expect to deliver all project results to sponsors by July 2006. The project includes an integrated package of deliverables:

- A one-day **workshop** will include summarized study results and discussion on the strategies utilities have been using to justify infrastructure investments focusing on reliability, power quality, and customer service improvements. (We will host this workshop at a location designed to minimize travel time for sponsors.)
- A detailed **report** will examine best practices in rate filings for distribution system investment to improve power quality and reliability—including the specific factors most closely associated with regulatory and ratepayer acceptance.
- A study **website** will provide ongoing access to links to important documents that were used as source material, along with annotated summaries of the documents.
- Sponsors have **direct access to EPRI Solutions expert staff** for help applying project results to their specific situations, along with methodological questions.

An on-site presentation and discussion of results with key personnel at a sponsoring utility can also be provided at an additional cost.

Pricing

Sponsorship of this multiclient project is open to electric utilities for a fee of $25,000 per organization. Companies who commit to sponsorship **prior to February 28, 2006**, will have the ability to help prioritize the key issues to be addressed in the analysis.

About EPRI Solutions

EPRI Solutions, Inc. offers an integrated portfolio of engineering services, business consulting, and information products to deliver immediate benefits and lasting value to our power-industry clients. EPRI Solutions' services and products help utilities and other organizations around the world meet today's technical, financial, and organizational challenges—improving operational efficiency, enhancing customer satisfaction, and increasing profitability. Our team of multi-disciplinary professionals—including world-class experts in numerous areas—has built a solid track record of success by leveraging the science and technology resources of our parent organization, the Electric Power Research Institute (EPRI), along with our unique laboratory facilities and in-depth knowledge of industry best practices.

Contact

To receive a participation form or for more information on sponsorship, please contact EPRI Solutions at info@eprisolutions.com, or call our customer service department at 877-976-4681.

For additional information about the proposed approach or the study deliverables, please contact any of the following project team members:

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