EB-2007-0050

ONTARIO ENERGY BOARD

IN THE MATTER OF the *Ontario Energy Board Act, 1998,* S.O. 1998, c.15, Schedule B;

AND IN THE MATTER OF an Application by Hydro One Networks Inc. pursuant to section 92 of the Act, for an Order or Orders granting leave to construct a transmission reinforcement project between the Bruce Power Facility and Milton Switching Station, all in the Province of Ontario.

EVIDENCE OF THE INTERVENOR THE SAUGEEN OJIBWAY NATIONS

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I N D E X

IN THE MATTER OF the *Ontario Energy Board Act*,1998, S.O. 1998, C.15 (Sched. B);

IN THE MATTER OF an Application by Hydro One Networks Inc. pursuant to section 92 of the Act, for an Order or Orders granting leave to construct a transmission reinforcement project between the Bruce Power Facility and Milton Switching Station, all in the Province of Ontario.

AFFIDAVIT

of

WHITFIELD A. RUSSELL

on behalf of

THE SAUGEEN OJIBWAY NATIONS

Statement of Qualifications

1. My name is Whitfield A. Russell. I am a public utility consultant and principal in Whitfield Russell Associates. I hold a Bachelor of Science degree in Electrical Engineering from the University of Maine, a Master of Science degree in Electrical Engineering from the University of Maryland, and a Juris Doctor degree from Georgetown University Law Center. I have been accepted as an expert on bulk power systems in more than 150 proceedings before State and Federal courts, administrative agencies and other tribunals in approximately 30 States and in two other Canadian provinces (Manitoba and Alberta). My complete resumé and a description of cases on which I have worked are attached as Exhibit No. 1.

2. I am testifying on behalf of the Saugeen Ojibway Nations. The purpose of my testimony is to review the analyses performed by the Ontario Power Authority

("OPA"), Hydro One Network, Inc. ("Hydro One"), and the Independent Electric System Operator of Ontario ("IESO") in support of the application to construct a proposed Bruce-to-Milton double circuit 500 kV transmission line project ("Bruce-Milton Lines", composed of two 500 kV circuits on a single set of towers).

3. My analysis has been informed by the scope and standard of review set out in the Board Issues List in this matter as revised, the Ontario Energy Board Act, and other relevant policy.

Summary of Findings

4. My principal findings are:

A. Based on the evidence filed in this matter regarding existing and committed generation from the Bruce area, and the existing transmission infrastructure, Hydro One's proposal to construct a new double circuit 500 kV transmission line project from Bruce to Milton cannot be justified as a better project than the reasonable alternatives.

B. Hydro One has misstated the need for transmission capability by including in its analysis significant sources of generation that have not been committed or approved. Hydro One includes in its analysis 1000 MW of potential wind generation that is identified in the Integrated Power System Plan ("IPSP") that has not yet been approved, committed or developed and that would require the construction of further transmission infrastructure to realize. Hydro One also assumes the refurbishment of 4 Bruce B nuclear reactors producing approximately 3400 MW of generation beginning in 2018 – a decision that will not be made or approved until some time in the future.

C. Hydro One’s faulty assessment of need has resulted in (1) its preference for a proposal that would result in excessive transmission capability given the existing and committed generation capacity in the Bruce area, and (2) its dismissal of available and reasonable alternatives to its preferred project, including alternatives Hydro One identifies in its application as potential near term and interim measures.

D. The construction of excessive transmission capacity will also cause the impedance of the transmission system to be reduced, thereby inducing more power to flow from generation in the United States through Ontario’s grid and back to loads in the United States. This well known “circulating loop flow” problem uses up Ontario’s transmission capacity, adds to transmission losses, and requires costly reactive compensation and off-setting measures.

E. A corrected assessment of need suggests that the near term and interim measures identified by Hydro One are sufficient to provide any transmission upgrades that are required to serve the existing and committed generation from the Bruce area.

F. The installation of series capacitors on the existing transmission infrastructure in Southwestern Ontario is a better alternative than Hydro One’s proposed construction of the new Bruce-Milton Lines. Series capacitors are a benefit to consumers in that they will cost considerably less ($97 million) than the proposed $635 million Bruce-Milton Lines and will avoid the premature construction of transmission capability that is surplus to Ontario’s demonstrated needs. In addition, series capacitors will optimize the use of existing infrastructure and public service facilities in that series capacitors can be added to facilities in existing rights-of-way south of the Bruce-Milton path. Use of series capacitors will protect the interests of consumers with respect to reliability in that such an upgrade would be less susceptible to construction delays than would two entirely new circuits on expanded rights-of way, would meet industry reliability criteria and would avoid undue concentration of delivery facilities on the Bruce-Milton right-of-way that has historically been susceptible to tornadoes. The series capacitor alternative would not prejudice a later decision to add the Bruce-Milton Lines if their need is established in the future.

G. Series capacitors coupled with generation rejection will be a reasonable alternative for delivering the output of as many as eight units at the Bruce Nuclear Generating Station ("Bruce NGS") plus the output of approximately 1075 MW of wind generation, approximately 375 MW more than currently exists or is committed. That is, the existing 500 kV transmission system configuration augmented by series capacitors and generation rejection will be sufficient to deliver all existing and committed generation capacity in the vicinity of the Bruce Complex without the proposed Bruce-Milton Lines. Accordingly, a decision to construct the proposed Bruce-Milton Lines should not be made until there is an approved decision for, and commitment to, new nuclear generation or substantial new wind generation in the Bruce area.

H. The generation rejection ("GR") of nuclear units at the Bruce complex is well established practice. Multiple (simultaneous or overlapping) forced outages of critical transmission lines emanating from the Bruce Complex have historically been dealt with by implementing a Special Protection System ("SPS") that would allow for the rejection of as many as four Bruce nuclear generating units (meaning that four units could be instantaneously shut down for a short time) and shedding up to 1,500 MW of load in the Greater Toronto Area. Because such multiple transmission line forced outages are extremely rare, this historical practice has provided a high degree of reliability with no actual historical costs incurred but for the costs of implementing the SPS. Under the recently published Regional Reliability Reference Directory #7, Special Protection Systems, December 7, 2007, Directive No. 7 of the Northeast Power Coordinating Council, ("NPCC"), any SPS that was previously in use may continue to be used even if it does not meet the new criteria. See Exhibit No. 2 at p. 2. Accordingly, Ontario may continue to use its existing SPS under NPCC criteria.

I. Series capacitors in combination with generation rejection is a far more cost-effective and economically efficient alternative to the project proposed by Hydro One. Further, this alternative is scalable to accommodate both significantly increased or decreased generation from the Bruce area in the future. In contrast, Hydro One's proposal cannot be scaled down in response to reduced generation from the Bruce area, and would result in excess transmission capacity in the near term, and substantial excess capacity in the event that there is a significant reduction in generation from the area in the future.

J. Hydro One claims a need for transmission capability to deliver 100% of the maximum expected installed capability of future wind generation (both committed and uncommitted) and Bruce nuclear units after the loss of both 500 kV lines on the most critical double circuit towers emanating from the vicinity of the Bruce NGS (referred to as firm transmission service). Hydro One makes this claim despite the facts that (a) OPA relies on only 20% of the installed capability of wind generation in meeting peak demands and (b) on average, wind energy production represents only 29% of the installed capability of the wind generation. In other words, Hydro One asserts that the transmission system should be built to deliver the full nameplate output of the Bruce NGS units coincident with the overstated wind generation capacity. For Hydro One to build and operate firm transmission capacity for delivery of the full installed capability of intermittent energy sources (that is significantly above the projected on-peak output on which Ontario relies) is not consistent with sound system planning principles, and is neither cost-effective nor economically efficient.

K. Hydro One’s analysis of the comparative economics of various transmission expansion alternatives cannot be relied upon for several reasons, including the following; Hydro One has refused to release the underlying models and data, denying the Board the benefit of any independent audit of Hydro One’s analysis. The analysis models a forecast amount of future wind generation (1000 MW) that the Ontario Government has not yet committed to purchase. It also assumes upgrades to the Bruce B units that may not occur until 2018 or later. Further, the feasibility of an alternative that employs series capacitors and generation rejection was determined on the basis of an understated transfer capacity (7075 MW as opposed to the more appropriate transfer capacity of 7475 MW). These assumptions unreasonably increase the forecast cost of undeliverable energy, particularly with respect to the alternative involving series capacitors and generation rejection. Lastly, the analysis fails to account for the significant costs associated with remedying the “circulating loop flow” problem that will be caused, or exacerbated, by the construction of new Bruce Milton lines.

Project Need and Justification – Hydro’s Case

5. OPA attributes the need for new transmission facilities to the Minister of Energy’s directives dated June 13, 2006, in which directives the OPA was required to strengthen the transmission system in order to:

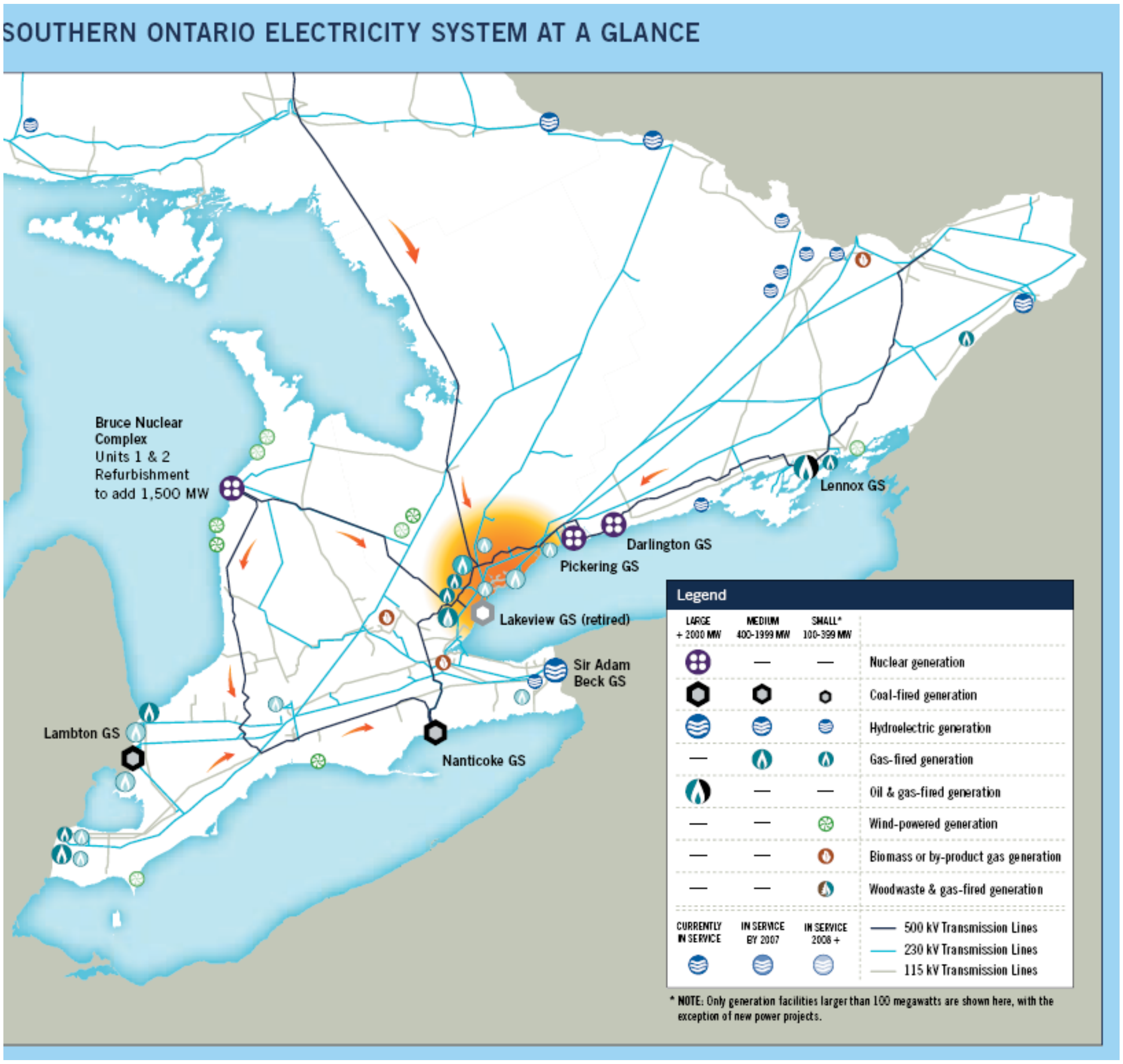
- Enable the achievement of the supply mix goals of the directive, including reduced usage of coal-fired generation and increased usage of nuclear generation;
- Facilitate the development and use of renewable energy resources such as wind power;
- Promote system efficiency and congestion reduction and facilitate the integration of new supply, in a manner consistent with the need to maintain system reliability cost-effectively.

See Hydro One's Application, Exhibit B, Tab 6, Schedule 5, Appendix 1, page 2.

6. More specific to the Bruce area, Hydro One's stated need for the Bruce-Milton Lines is based on OPA's determination that the lines are allegedly required in order to meet the increased need for transfer capability from the Bruce Complex to the Toronto area associated with (a) development of committed and forecast wind generation, (b) the return to service of two nuclear units at the Bruce NGS and (c) vaguely defined upgrades of other Bruce Units. As part of the arrangement to return to service two nuclear units, the Ontario Government has committed to pay for the energy output that Bruce arguably could produce in the future but would be unable to produce because of insufficient transmission capability ("deemed energy"). See Exhibit No. 3. OPA says that unless enough transmission capability is available, the government is likely to be paying for Bruce energy without receiving all of the actual energy that could be generated. OPA further determined that, despite being included in the OPA's preliminary IPSP, the Bruce-Milton Lines project cannot await completion of the IPSP if they are to be placed in service by December, 2011. See Hydro One's Application, Exhibit A, Tab 1, pp 1-2.

7. The transmission system in Southwestern Ontario is composed of 115 kV, 230 kV and 500 kV transmission lines. The primary load center is in Toronto. Power tends to flow toward the Greater Toronto Area ("GTA") from the Bruce Peninsula and from Hydro One's interconnections with utilities in New York and Quebec to

the east and in Michigan to the west of Southwestern Ontario. The first map below shows the Southern Ontario transmission system, while the second map shows the existing lines as well as existing and proposed generation in the area more immediate to the Bruce Complex and the GTA.



Source: Application, Exhibit B, Tab 6, Schedule 4, “The Ontario Reliability Outlook”, March 2007, page 6.

Source: Application, Exhibit B, Tab 6, Schedule 4, "The Ontario Reliability Outlook", March 2007, page 8.

8. The OPA asserts that new 500 kV double circuit lines are needed from Bruce to the GTA. See Hydro One's Application, Exhibit A, Tab 2, p. 1 of 5. Hydro One intends to increase transmission capacity away from the Bruce area from an existing transfer level (that Hydro One states is approximately 5000 MW) to a level of about 8100 MW in order to accommodate the maximum possible output of all eight Bruce units (refurbished and upgraded) as well as 700 MW of committed wind generation and about 1000 MW of nameplate capacity of

anticipated but uncommitted wind generation projects. Hydro One asserts that nearly all of this power must be transmitted to the GTA in order to serve loads in that area and replace the output of to-be-retired coal generation. See Exhibit No. 4, excerpts from the October 15, 2007 Technical Conference at pp. 15-16, and Application, Exhibit B, Tab 1, Schedule 1, pp. 3-4.

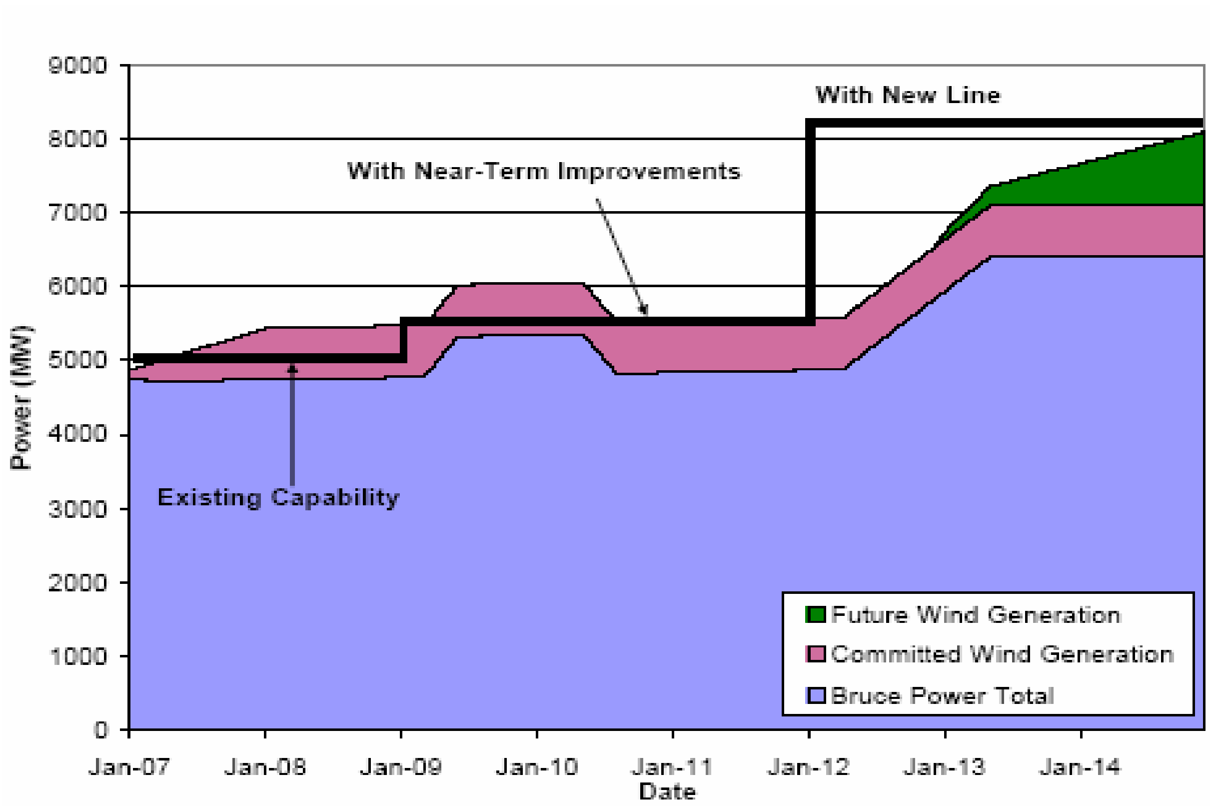
Project Need and Justification – Analysis of Hydro One's Assessment of Need

9. It is critical to note that in its assessment of the need for its proposed project, Hydro One, relying on OPA analysis and reports, has included two significant sources of generation that have not been approved or committed. First, Hydro One has included 1000 MW of potential wind generation from the Bruce region that has been identified in the IPSP. Second, Hydro One has included in its analysis 4 refurbished Bruce B units with an estimated combined output of approximately 3400 MW. The inclusion of these two unapproved and uncommitted sources of generation has fundamental implications both as a justification for the proposed project from a system design perspective, as well as for the economic evaluation of the project and other reasonable alternatives.

10. A proper need analysis ought to be based on existing and committed generation from the Bruce area. Removing the two major sources of unapproved and uncommitted generation that have been included in Hydro One's analysis results in a picture of the transmission facilities that are required to service the Bruce area dramatically different from that conveyed by Hydro One. This difference is evident when comparing Hydro One's graphic representation of the need for the new line, shown in Figure 1, to my analysis, shown as Figure 2. As can be seen in Figure 2, the amount of generation that needs to be accommodated in the Bruce area never exceeds 7000 MW, using actual existing ratings and removing uncommitted generation.

Figure 1

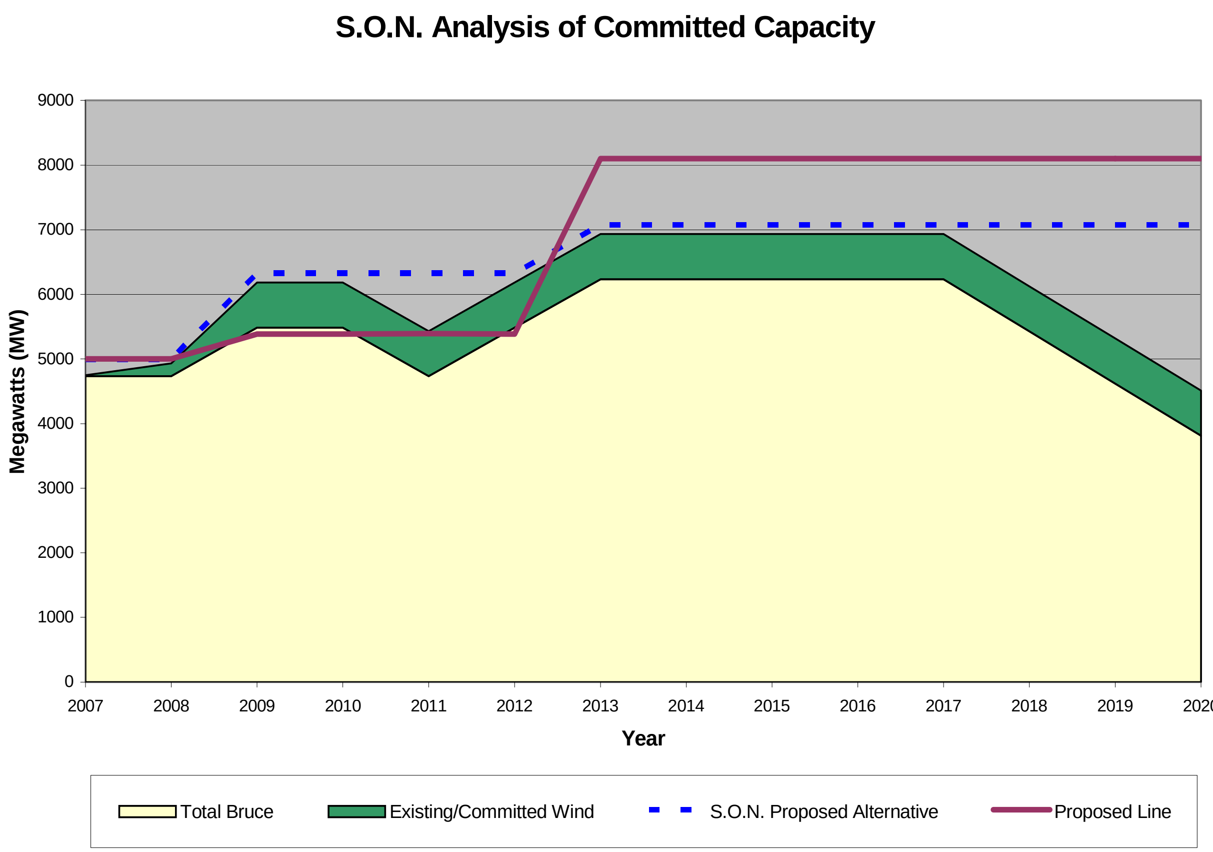
Hydro One Transmission Capacity with Near-Term Upgrades and New Line



Source: OPA

Source: Application, Exhibit B, Tab 3, Schedule 1, Figure 1.

Figure 2



11. My analysis of the need for transmission upgrades is based on the actual existing and committed generation planned for the Bruce area as described in filed evidence in this matter. My analysis indicates that, while some transmission enhancement is required in order to serve all of the approved generation capacity in the Bruce area, the proposed Bruce-Milton Lines are neither the most economic nor the best suited upgrades for the amount of capacity actually committed at this time.

12. Given the several alternative scenarios for expanding generation from the Bruce region that may possibly develop in the future, any transmission project chosen now should be sufficiently scalable to accommodate various future scenarios. As

discussed elsewhere herein, my proposed alternative is less costly than Hydro One's preferred plan, and is scalable. E.g., the series capacitors and generation rejection incorporated in my proposal do not preclude further upgrades and can be expected to add to the transfer capability of almost any subsequent transmission system upgrade. For example, if one or more 500 kV Bruce-Milton circuits are later determined to be needed because increased generation capacity is approved, series capacitors can be expected to enhance the N-1 transfer capability of that upgraded system.

13. According to the revised filing, there is approximately 4734 MW of capacity at the Bruce NGS. Also, there is approximately 15 MW of existing wind generation in the vicinity of the Bruce area. This combined capacity of the existing nuclear and wind generation capability totals 4750 MW, 250 MW less than the 5000 MW of average generation capacity and minimum transmission transfer capability that OPA and Hydro One cite as currently existing. See Hydro One's Application, Exhibit B, Tab 1, Schedule 1, p. 3 and Exhibit B, Tab 6, Schedule 5, Appendix 1, p. 3. During the Technical Conference, an OPA representative stated that the existing generation in the vicinity of the Bruce Complex has an installed capability of 4749 MW. Exhibit No. 4 at p. 15.

14. OPA intends to add another 1500 MW of generation by refurbishing Units 1 and 2 at Bruce A. While doing this work, OPA will also be removing the other two Bruce A units. All eight units are scheduled to be operating as of 2013. With the addition of the two Bruce A units, Bruce NGS capacity will total 6234 MW. Responses to Interrogatories indicate that upgrades of 40 MW are to be performed on each Bruce B unit, increasing the total Bruce NGS capacity to 6400 MW.[1] Hydro One has not provided any information on the dates by which each of these upgrades will begin or be completed. Nevertheless, Hydro One uses the full 6400 MW of capacity in its planning and economic studies of the alternatives to the Bruce-Milton Lines. OPA has already committed to purchase 675-700 MW of

[1] See Exhibit No. 5, Response to Fallis Interrogatory #26, List 1.

wind generation capacity to be sited in the vicinity of the Bruce Complex. The sum of this existing and committed generation is approximately 6900 MW, if the Bruce B upgrades are not included (as no date for the upgrades was provided). The chart below lists the maximum amount of transfer capacity that will be required year-by-year in order to deliver all of the committed generation planned near the Bruce. The chart uses Hydro One's rating of 5000 MW for the existing system, but, as described below, there are a number of issues that must be addressed surrounding the amount of transfer capacity necessary to transmit power from the wind generation.

Forecast of Capacity in the Bruce Area

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Generation (MW)														
Existing/Committed Wind	15	200	700	700	700	700	700	700	700	700	700	700	700	700
Bruce Existing	4734	4734	4734	4734	4734	4734	4734	4734	4734	4734	4734	4734	4734	4734
New Bruce			1500	1500	1500	1500	1500	1500	1500	1500	1500	1500	1500	1500
Bruce out for Maintenance			-750	-750	-1500	-750	0	0	0	0	0	0	0	0
Bruce B License Ends												-808	-1616	-2424
Total Bruce	4734	4734	5484	5484	4734	5484	6234	6234	6234	6234	6234	5426	4618	3810
Total Generating Capacity	4749	4934	6184	6184	5434	6184	6934	6934	6934	6934	6934	6126	5318	4510
Existing Transfer Capacity	5000	5000	5000	5000	5000	5000	5000	5000	5000	5000	5000	5000	5000	5000
Need for Transfer Capacity	NA	NA	1184	1184	434	1184	1934	1934	1934	1934	1934	1126	318	NA

Also see Exhibit No. 6 for supporting Interrogatory Responses.

15. Hydro One's filing anticipates, and reflects plans to add, transmission capability for the development of another 1000 MW of potential wind generation capacity. See Hydro One's Application at Exhibit B, Tab 1, Schedule 1, p. 4 and Exhibit B, Tab 6, Schedule 5, Appendix 1, p. 4. I have not included this additional 1000 MW of future wind generation capacity in my chart above as (a) this potential wind generation capacity is identified in the IPSP, but is as yet unapproved, (b) according to the OPA, much of this 1000 MW of potential wind generation would require the construction of new gathering and enabler transmission lines before it could be realized, (c) no commitment has yet been made to develop or contract for this generation and related transmission facility requirements, and (d) in any event, firm transmission capability in the amount contemplated by Hydro One

would not be required to serve potential future wind generation amounting to 1000 MW, as explained below.

16. The chart above also shows the expected retirement of the Bruce B units. Data were not available on the expected end-of-life of the Bruce B units. However, the responses to Pollution Probe Interrogatories #3 and #4, List 1 (Exhibit No. 7) indicate that these units will be taken out of service beginning in 2018 for refurbishment. I assumed that one unit would retire each year, as the units entered service on a similar schedule back in the mid-1980s.

17. In contrast to the contentions of OPA and Hydro One that an additional 3100 MW (for a total of 8100 MW) of transfer capability is required, this chart shows that the needed amount of future transfer capacity is smaller. As noted above, Hydro One states that existing transmission capacity equals approximately 5000 MW. Using these assumptions, my calculations indicate that there will be a shortfall of approximately 1200 MW in 2009-2011, and approximately 1950 MW by 2013. This shortfall of approximately 2000 MW will last only until 2018, at which time the Bruce B units will begin to retire unless further commitments are made.

Near-Term and Interim Measures Sufficient to Meet Actual Need

18. Certain plans for constructing transmission upgrades already are in place for the Bruce Area. The filing describes what are called “near-term upgrades.” Near-term upgrades are those upgrades planned and in-service in 2009, which include:

    a. Upgrades to the Hanover-Orangeville 230 kV line

    b. Addition of Dynamic and Static Reactive devices.

    These two near-term upgrades are projected to result in a 385-400 MW increase in transmission capacity (See Application Exhibit B, Tab 6, Schedule 5, Appendix 5, p. 46 and Exhibit No. 8, Response to Interrogatory Pollution Probe #16, List 2, Table 1).

19. Hydro One has also proposed “Interim Measures,” one of which (restricting generation additions) is to be in place only until the proposed Bruce-Milton Lines are constructed. Hydro One claims that the majority of these measures should not be in place for a lengthy period of time, or be installed in place of the proposed line. Hydro One’s Interim Measures include:

a. Restricting further generation development in the Bruce area, primarily refusing to contract for potential new wind capacity in the Orange Zone area, which OPA has implemented (Exhibit No. 4, pp. 33-34 and Application Exhibit B, Tab 6, Schedule 5, Appendix 5, p. 50).

b. Expanding the Bruce Generation Rejection scheme (“GR”), a type of special protection system (“SPS”) that has been in effect since the mid-1980s (Ibid).

c. Installation of series capacitors/series compensation (Ibid). According to Hydro One, the earliest installation date possible for series compensation is 2011, and the cost of this interim measure is estimated to be $97 million, only about one-sixth the cost of the proposed Bruce-Milton 500 kV line. Hydro One is not inclined to pursue this interim measure.

20. Table 1 of the Response to Pollution Probe Interrogatory #16, List 2 at Exhibit No. 8 shows that the use of the Near Term Measures and the Bruce SPS arrangement can provide up to 6326 MW of transfer capability. When the Near Term Measures are combined with series compensation in combination with the Bruce SPS arrangement, there are two transmission capabilities referenced: 6326 MW and 7076 MW. Hydro One is differentiating between an SPS that is armed during normal conditions, as has been its practice historically and currently, and the use of an SPS that is armed only under contingency conditions—once an outage of a facility has already occurred. As I will describe later, Hydro One wishes to move from (a) its current practice that permits continuous arming of SPS and generation rejection under N-2 contingency conditions (and that is projected to achieve at least 7076 MW of transfer capacity with series capacitors and GR) to (b) a more restrictive practice of arming GR (the GR SPS is armed

only after a single or double outage and activated by occurrence of the next contingency). As is clear from my chart above, 7076 MW of transfer capacity is sufficient to serve all of the committed nuclear generation at the Bruce NGS as well as the committed wind generation under contract at this time.

21. Hydro One asserts that the proposed Bruce-Milton Lines will increase transmission capacity to approximately 8100-8200 MW (Exhibit No. 4, p. 45 and Application Exhibit B, Tab 6, Schedule 5, Appendix 4 and Exhibit No. 8). This amount of increased transmission capacity appears to be designed to allow Hydro One to interconnect all of the committed wind generation, as well as allow Hydro One to interconnect up to 1000 MW of unapproved and uncommitted potential wind generation from the Bruce region. In addition, the excess transmission capacity would permit additional generation to be obtained from the Bruce NGS in form of a refurbishment of Bruce B reactors at the end of their operational lives, as well as increased generation from additional reactors beyond the eight that are presently installed.

22. The increased transfer capacity that would be available with the construction of the proposed Bruce-Milton Lines could have a deleterious effect on Ontario's transmission infrastructure and consumers. As the actual transmission system could accommodate 8100 MW after the proposed project is built, while existing generation capacity would only reach approximately 6900 MW until subsequent generation capacity additions are approved and go into operation, the impedance of the transmission system will be reduced. This lowered impedance will induce more power to flow from generation in the United States through Ontario's grid to loads in the United States. This phenomenon is the well-known "circulating loop flow" problem that soaks up Ontario's transmission capacity, adds to the transmission losses on Ontario's grid and adds to the need for reactive compensation and expensive measures to offset such loop flows. Even though any upgrade to transmission facilities in the vicinity of the Bruce Complex will reduce the impedance of Ontario's grid to loop flows, Hydro One's proposed

upgrades will tend to exacerbate the loop flow problem more than would an alternative that is scalable to match the actual generation from the area. One such alternative involves the installation of series capacitors and continued implementation and use of a generation rejection scheme.

Project Alternatives

23. Hydro One and OPA have determined that their preferred solution is the new double circuit 500 kV lines from Bruce-to-Milton, situated on an expansion (widening) of existing rights-of-way. In its evidence, Hydro One indicates that its proposal is better than reasonable alternatives, in large part, because it avoids the need to install series capacitors in the short run and lessens the need for rejecting wind or nuclear generation to deal with multiple line outages.

24. However, from the evidence, it does not appear that Hydro One's proposal is a better project than other available and reasonable alternatives. Further, Hydro One's preferred plan adds transfer capability well before it is demonstrated to be needed, requires substantial amounts of additional land to be set aside for rights-of-way, is projected to cost approximately six times as much as would series capacitors and leaves Hydro One susceptible to increased loop flows and the loss of increased amounts of transfer capacity should tornadoes take out a complete right-of-way (as has happened once on the Bruce-Milton right-of-way). Because it involves construction of new infrastructure on additional rights-of-way, implementation of Hydro One's preferred alternative is inconsistent with Section 1.62 of the 2005 Provincial Policy Statement, as found at Application, Exhibit B, Tab 6, Schedule 5, Appendix 13, page 10.

25. My analysis suggests that the series compensation alternative combined with the continuation of the existing SPS arrangement (or an SPS arrangement that would reject even fewer generating units) would reliably satisfy, or even exceed, the level of transmission capacity needed to deliver all of the existing and committed

generation capacity in the Bruce area, and has a number of significant advantages over the project proposed by Hydro One. According to data provided at Application, Exhibit B, Tab 6, Schedule 5, Appendix 5 page 52, the addition of series capacitors coupled with one Bruce unit under GR will bring transfer capacity up to 7300-7400 MW. In response to Saugeen Ojibway Nations Interrogatory #2 (Exhibit No. 9) and Pollution Probe Interrogatory #16 (Exhibit No. 8), Hydro One indicates that this transfer capacity (Near Term Measures + Series Capacitors + BSPS for use under normal conditions) has been dropped to 7076 MW without any explanation for the discrepancy between this amount and those shown previously in other IESO and Hydro One sources. In any event, it is clear that even 7076 MW of transfer capacity is sufficient to deliver the output of all 8 Bruce units plus the output of committed wind generation. Furthermore, an even higher transfer capability is indicated in Exhibit No. 10, Hydro One's response to Saugeen Ojibway Nations Interrogatory #10, List 1. I understand from that response that series capacitors plus generation rejection will enable Hydro One to deliver the output of eight Bruce nuclear units plus 1075 MW of wind generation, which exceeds the amount of existing and committed wind generation in the region by about 375 MW.

Project Alternatives – Series Compensation

26. Hydro One and the IESO have both studied the introduction of series capacitors on transmission facilities in the Bruce area. Hydro One requested a study of the Southwestern Ontario Transmission System, and a report was issued by ABB Consulting on November 30, 2005. This Draft Report (provided in response to Pappas Interrogatory #1, List 1, excerpts provided in Exhibit No. 11) concluded that

> . . . both the power flow and dynamic simulation results confirm that the proposed series compensation of the 500 kV lines is feasible and will meet the power transfer requirements. The simulation results show that further optimization (both technical and economic) of both the series and shunt compensation levels is desirable. See page S-4.

After this Draft Report was issued, Hydro One requested that the IESO perform a System Impact Assessment to determine whether series capacitors could increase the capability of the existing transmission facilities in order to deliver power from the Bruce area, including additional output from Bruce Units 1 and 2 and 725 MW of committed wind. The IESO study was also meant to determine whether series capacitors could avoid the need for rejecting any generation in response to a "first contingency," the loss of both existing Bruce-to-Milton circuits (which is actually an N-2 event).

27. The IESO Study determined that 30% series compensation could provide enough transfer capability to deliver the output of seven Bruce units as well as 925 MW of wind generation (See Exhibit No. 12 at 9-10). This analysis of series compensation did not include generation rejection. The transfer capability was limited to this amount because of the IESO's goal to avoid GR in response to a "first contingency" (N-2 event), even though the system historically has been operated by using GR in response to a "first contingency" (N-2 event). Table 1 in Exhibit No. 8 reflects the IESO's recognition that arming the generation rejection scheme under normal conditions (rather than waiting for a contingency condition) would increase transfer capacity to 7076 MW. This is enough transfer capacity to deliver the output of all eight Bruce units and the committed wind generation. However, the IESO study still preferred the construction of new transmission lines.

28. Another report favorable to the use of series capacitors was published in October 5, 2007. It is the "*Final Report Due Diligence Study and Development of High Level Planning Specifications for the Installation of 500 kV Series Capacitor Banks in the Southwestern Ontario Transmission Network*," for the Ontario Power Authority, OPA Purchase Order 50000488, OPA Project Manager: Jim Lee, by Duane Torgerson, Dennis Woodford, Garth Irwin and Randy Wachal ("Due Diligence Report"). See excerpts provided at Exhibit No. 13. The full document was provided in response to Pappas Interrogatory #6, List 2. The Due Diligence

Report reviews (at 11 *et seq.*) hundreds of installations throughout the world of series capacitors manufactured by four major manufacturers. The Due Diligence Report finds that "Applying series compensation with series capacitors (SCAP) is an accepted method of increasing transfer capacity of a high voltage transmission line that is impedance limited." The report states (at 8) that "Series capacitor application to high voltage transmission lines, and at 500 kV is a mature technology in North America and around the world" that has been in use since 1948, including in Canada. The report notes that the effectiveness of series capacitors has been substantially improved over the years. This finding is made in the introduction (at 7) and again in the conclusions (at 52). Furthermore, the reliability of series capacitors is high. The Due Diligence Report states (at 31):

> [I]t is not unusual for series compensation systems, including their ancillary equipment, to be specified with guaranteed availability performance requirements of 99.6% to 99.7%. The number and duration of scheduled maintenance outages of fixed series capacitors (FSC) banks each year typically do not exceed 1 outage for a maximum duration of 12 hours with no more than 2 forced outages per year.

29. The Due Diligence Report indicates that problems associated with series capacitors can be overcome. It states (Summary at 2):

> Careful design of the Bruce special protection system (BSPS) can counteract reduced system reliability when adding series capacitors for these increased power flows but is a complex adjustment to do successfully. In addition, careful design applied to each series capacitor bank can minimize the impact of failure modes within the bank and its consequential negative influence on system reliability.

The report contains a warning about sub-synchronous resonance ("SSR"), yet states (at 9):

> Fortunately the mechanism of SSR, its analysis and design for prevention is now well known and a number of mitigating measures exist to address this issue . . . . Generally it is true that the lower the proportion of series compensation on a transmission line, the less likely the electrical series resonance will decrease damping of complementary shaft torsional

resonant modes and cause shaft damage.

30. These documents clearly indicate that series capacitors will work in lieu of the Bruce-Milton Lines, but that some additional fine-tuning is necessary. However, it appears that Hydro One wishes to treat the series capacitor alternative as one solely related to interim measures. Hydro One has expressed strong reservations[2] about using series capacitors as a long-term solution, and does not reconcile its reservations with the fact that series capacitors are very common in other parts of the world, especially within Canada and the United States where transmission systems operate under roughly the same regulatory and reliability criteria as does the transmission system in Ontario.

31. Furthermore, Hydro One has stated that series capacitors cannot be installed until 2011 at the earliest. This position seems unnecessarily restrictive. In fact, the facilities required to be installed require little if any new right-of-way or transmission towers. Although OPA earlier promoted implementation of series capacitors and generation rejection,[3] Hydro One has since shifted its preference away from series capacitors and toward the construction of its proposed Bruce-Milton lines.

32. Series capacitors alone will increase transmission capacity from 5385 MW to 6325 MW, and the transfer capacity would be even higher with the continuation of the existing GR plan to drop one Bruce unit upon loss of both circuits of the existing Bruce-Milton Lines. With GR included, transmission capability increases to no less than 7076 MW as noted in Table 1 of Exhibit No. 8, and this amount may be even more, as discussed later.

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[2] See Application, Exhibit B, Tab 6, Schedule 5, Appendix 2, p. 4 and Exhibit B, Tab 6, Schedule 5, Appendix 3.

[3] "10-Year Outlook: An Assessment of the Adequacy of Generation and Transmission Facilities to Meet Future Electricity Needs in Ontario from January 2006 to December 2015," Independent Electricity System Operator, August 15, 2005, provided in response to Pappas Interrogatory #1, List 1. See Exhibit No. 14 at page 47.

Project Alternatives - Generation Rejection as a Component of a Reliable Alternative

33. Hydro One indicates that the existing generation capability at Bruce is approximately 5000 MW from six units. As noted previously, Hydro One has since provided a lower figure for the existing generation at Bruce, indicating that the net continuous rating of the existing Bruce NGS is 4734 MW. However, there was a period during 1987 through 1995 when all eight units at Bruce were operating. The combined capacity of these units is approximately 6200-6400 MW. During the Technical Conference held on October 15, 2007, Hydro One and OPA were questioned about this inconsistency. OPA's representative indicated that, in the past, the existing transmission facilities emanating from Bruce had enough capacity to transmit power from the eight previously-installed Bruce units. According to the OPA representative, the transmission system can no longer handle eight Bruce units because the transmission system connected to Bruce NGS has become loaded with increased power flows from non-Bruce generation in the west and because a heavy water plant near Bruce (a plant load that formerly absorbed 300 MW of Bruce's output locally) is no longer operating. Hydro One asserts that the prevailing direction of power flows has changed from its former east to west direction to the west to east direction and will presumably continue flowing in that direction (Exhibit No. 4, pp. 22-23). As a result, Hydro One takes the position that the transmission capacity out of Bruce is now limited to approximately 5000 MW.

34. However, based on responses to interrogatories, it appears that the transmission system in existence during the period that all eight Bruce units were operating (1987-1995) was able to deliver the output of all eight Bruce units only by means of a Special Protection System ("SPS") arrangement. See Exhibit No. 15 (Ross-IESO Interrogatory #10, List 1, with quotation below at P 36). That SPS involved use of generation rejection following substantial outages of transmission facilities. The prior practice permitted substantial amounts of Bruce generation to be

rejected under rarely occurring and tightly defined conditions from the mid-1980s through 1995.

35. Hydro One is now unwilling to continue use of the Bruce SPS that has been relied on historically. This evolution in attitude is now a major factor relied upon to justify the need for new transmission facilities, and is explained in some detail in Exhibit No. 14, “10-Year Outlook: An Assessment of the Adequacy of Generation and Transmission Facilities to Meet Future Electricity Needs in Ontario from January 2006 to December 2015,” Independent Electricity System Operator, August 15, 2005, provided in response to Pappas Interrogatory #1, List 1. The 10-Year Outlook states at pp. 45 *et seq*. [emphasis added]:

> **5.1.7 System Requirements Associated with the Incorporation of Bruce Units**
>
> The Bruce system consists of eight nuclear units, totaling approximately 6,500 MW of capacity, connected to the power system through four 500 kV lines (two circuits from Bruce to Milton TS, one of which continues on to Claireville and two circuits from Bruce to Longwood TS), and six 230 kV circuits (two circuits from Bruce to Orangeville, two circuits from Bruce to Detweiler and two circuits to Owen Sound, one of which connects to the 115 kV network through to Essa). The Bruce complex is the largest concentration of generating units in North America.
>
> The generation was installed over the mid 70’s to mid 80’s. Four units were removed from service in 1998, at the same time as four Pickering units. Of these four Bruce units, two units have since been returned to service in 2003. Two units (1 and 2) remain out of service.
>
> The transmission additions constructed to incorporate the station into the Ontario network were not as desired by Ontario Hydro. The preferred implementation included a double circuit 500 kV line from Bruce to Essa in the Barrie area. Public opposition to these circuits ultimately prevented this construction. The Bruce to Longwood 500kV circuits were installed as a somewhat less capable alternative. As a result of this change, the full output of the Bruce complex could not be accommodated by the transmission system. In order to increase the capability of the transmission system to the level required, an automated “Special Protection Scheme” (SPS) was installed. In taking this step, the reliability of both the Bruce generation and many customers in Ontario was reduced to achieve increased economic benefits of the Bruce complex. In essence, the SPS

allows for detection of certain power system events and immediately disconnects generators at Bruce and a large amount of customer load throughout southern Ontario to prevent a system disturbance such as that experienced in August 2003.

Without the SPS, Bruce output is limited to approximately 5,000 MW (capacity equivalent to approximately six Bruce units). With the SPS, Bruce output with eight units in operation (6,500 MW) could be accommodated provided up to four units (3,200 MW) were 'rejected' or disconnected instantaneously together with 1,500 MW of customer load (approximately half the load in downtown Toronto). These extensive and complex automatic actions, representing by far the largest use of an SPS by an interconnected system operator, were considered a temporary measure until additional transmission could be constructed. Ontario's neighbouring system operators insisted on stringent conditions with respect to the design and use of the SPS in order to protect their own systems from a cascading disturbance. The majority of the SPS has not been used in over a decade following the shutdown of four Bruce units in 1998.

In the consideration of additional Bruce generation, it is important to understand the relationships of the various factors which impact on the ability of the system to accommodate increased Bruce generation, as well as how the evolution of the electricity system has affected this capability. This information is summarized in the following table.

[Table deleted. That table makes the points that (1) more west-east power flows are superimposed on the Bruce transmission system because Ontario formerly exported power to Michigan and now imports power from Michigan and has added substantial thermal generation near Sarnia and Windsor, (2) that the Nanticoke coal units are becoming less reliable, and (3) that loads in the GTA have grown, power factor has declined, and generation in the GTA has declined.]

In each case, the evolution of the system has been to reduce the capability of the system to accommodate additional Bruce generation. Of course this is not exclusively true; for example, Darlington was constructed to help meet GTA load, expansion of the 500 kV network in south western Ontario has been undertaken and a large number of shunt capacitors have been added in the GTA. However, in general, the net effect has been negative from the perspective of accommodating additional Bruce generation.

In addition, the past reliance on the large 'Special Protection Scheme' to accommodate Bruce output is no longer a desirable practice. The three and four unit rejection associated with this scheme as well as associated customer load rejection have not been required to be used in a decade. The experience of the August 2003 blackout has altered industry and system operators view of the risks associated with use of these schemes. The side-effects of their operation may no longer be acceptable. The IESO does not recommend reliance on an SPS of this magnitude that involves the rejection of more than 2 generating units combined with extensive load rejection. There is a high degree of uncertainty with respect to our neighbours' agreement with such a scheme's future use. **The IESO believes it is prudent to enhance the transmission system so that generation rejection is limited to 2 Bruce units, and the load rejection portion of the special protection scheme is not required to be used in conjunction with generation rejection to maintain Bruce stability.** The load rejection portion of the scheme should be maintained only to overcome difficulties in the operating time frame that would otherwise require pre-contingency load shedding. From the late 1990's this was not a major concern as there were no firm plans to rehabilitate units at Bruce. When this became desirable, **the studies performed by the IESO, Hydro One and Bruce Power have identified the need for transmission expansion to accommodate additional generation at Bruce. This may take the form of series compensation of existing transmission lines or the addition of new transmission lines.**

In summary, the existing system is much less capable of accommodating additional supply at Bruce than it was in the past. A number of factors associated with the dynamic and changing nature of the system have contributed to this including:

- High load growth in the GTA, particularly in summer as air conditioner use has surged;
- Changing nature of the load in the GTA;
- The shutdown of Pickering A;
- The shutdown of Lakeview;
- The growth of imports from Michigan on-peak;
- The addition of generation in southwest Ontario;
- The overall reduction in dependability of some OPG facilities; and
- **Changing industry expectations with respect to use of large 'Special Protection Schemes'**.

Even with transmission enhancements, it is recognized that the incorporation of additional Bruce units together with the need to cease burning coal at Nanticoke will require significant changes in the supply and delivery infrastructure.

Fortunately, the same types of system developments required to eliminate the need for Nanticoke generation described earlier [in] this section are the same enhancements needed to accommodate additional generation at the Bruce site. These developments include the following:

- Installation of generation in proximity to the large GTA demand. Location of generation close to the load facilitates the installation of additional generation at Bruce in two ways; first, less energy needs to be transported long distances to the GTA reducing competition for transmission capability between Nanticoke and Bruce, and second, reactive power needs of the system are met by the local generation in the GTA;
- Installation of series compensation in the 500 kV lines serving Bruce and Nanticoke. This form of compensation reduces the need for reactive power to support the large power flows to support the GTA, and reduces the need for post-contingency voltage support; and
- Installation of shunt capacitors in southwestern Ontario. This form of compensation provides voltage support to the steady state power system, freeing up dynamic voltage control capability of generating units.
- As was the case for the shutdown of Nanticoke, it is unlikely that these measures will eliminate the need for dynamic voltage support from the Nanticoke site. The most effective means to provide this capability while meeting the government's policy to cease burning coal at Nanticoke is to convert several units to synchronous condenser operation.

While the IESO's 10-Year Outlook recommends the use of series capacitors and the rejection of two Bruce units, Hydro One now contends on the basis of analyses by the IESO that it should not employ generation rejection at all in order to deal with a first contingency. Hydro One would continue to use an SPS involving GR after a "first contingency" event (e.g., arm the SPS during maintenance of, or after a first contingency involving, loss of one or two 500 kV lines so that, in the event of a second contingency, generation can be dropped).

36. When asked to reconcile its request to build the Bruce-Milton Lines with the findings of the 10-Year Outlook (See Exhibit No. 15, Ross-IESO Interrogatory #10, List 1), Hydro One responded as follows:

> The 10-Year Outlook was released shortly after the IESO began consideration of using series compensation on the Bruce to Milton line. The 10-Year Outlook also notes that the IESO has yet to perform its full assessment of the impact of the 500 kV series capacitors at the paragraph immediately following the reference above.

> Detailed analyses were subsequently carried out for both series compensation and the Bruce to Milton line by the IESO and were presented in SIA documents. Please see the response to Pappas Interrogatory 1 for the series compensation SIA and Exhibit B, Tab 6, Schedule 2 for the Bruce to Milton line SIA.
>
> Consistent with the conclusion of the series compensation SIA, the installation of series capacitors is sufficient neither to accommodate all of the committed Bruce Area generation, nor to enable the development of additional potential wind resources in the area. The above references are accordingly consistent with each other.

37. It must be noted that this response is unsatisfactory as it is based on the same faulty system requirement assumptions identified in paragraph 9 above. Hydro One assumes that the Bruce B nuclear units will be refurbished, and that additional as-yet-uncommitted wind generation will be approved in the Bruce area. Hydro One also assumes that wind generation is required to be transmitted on a firm basis. Without these assumptions, Hydro One's dismissal of series capacitors coupled with generation rejection as a reasonable alternative is not justified.

38. Further, Hydro One has provided two differing amounts of transmission capability possible when the Bruce SPS is in place. Hydro One stated, in response to a data request concerning the transfer capability under the following scenario:

> (d) The existing transmission system with the existing generation rejection scheme, nearterm upgrades and series capacitors.
>
> • *Transfer capability*: Approximately 6325MW - with no G/R initiated.
>
> • *Transfer capability*: Approximately 7075MW - with the rejection of one Bruce unit initiated post-contingency
>
> Without generation rejection, the installation of series capacitors would allow the output from seven units at the Bruce Complex together with that from the 675MW of committed wind-turbine projects to be accommodated.

> With a single unit at the Bruce complex rejected post-contingency, the series capacitors would allow the combined output from all eight units at the Bruce Complex together with the committed wind-turbine projects to be accommodated.

See Exhibit No. 9. The rejection of two units, or the rejection of one unit plus blocks of wind generation, were not discussed. As I note, even more transfer capacity is achievable when series capacitors are employed in addition to a GR scheme.

39. Continuation of the existing, or more limited, practice of generation rejection from the Bruce area is acceptable for a number of reasons. First, historically, generation rejection has not resulted in significant undeliverable energy, as far as the data provided by Hydro One indicates. This is based upon Hydro One's answers concerning the loss of the existing 500 kV Bruce-Milton lines, as Hydro One would not provide data on the operation of the SPS schemes historically. Second, generation rejection in the Bruce context meets applicable regulatory and reliability criteria as indicated by a review of industry reliability criteria and Hydro One's responses to interrogatories.

40. Typically, an SPS of the kind implemented at Bruce is not called on often. Indeed, this SPS is necessary because of the very slight possibility that Southwest Ontario will suffer the outage of both existing circuits on the double circuit line from Bruce to Milton at the same time. Outages of even single 500 kV circuits are rare. The contingency outage of both existing circuits on a double circuit line at the same time is even rarer. The response to Board Staff Interrogatory #1.4 (Exhibit No. 16) notes that the GR scheme has been armed frequently, but Hydro One has no data on how often rejection has occurred.

41. In fact, the sustained outage rate (one minute or more) of double circuit 500 kV overhead transmission circuits on Hydro One's transmission system was 0.00100821 outages/year/km for the period covering 1990-2006. The momentary outage rate (lasting less than one minute) for the same facilities for the same time

period was 0.00175624 outages/year/km, See Exhibit No. 17, response to Pollution Probe Interrogatory #34 List 4. The outage rates for all 500 kV transmission lines in the Province are similarly low. Indeed, Hydro One's data on outages/year/km equate to one outage per 200-250 miles per year, even better than the general rule of thumb to the effect that transmission lines tend to experience only one outage per year per 100 miles of line and even fewer outages per mile on both circuits of double circuit lines.

42. Other data provided by Hydro One indicate that the number of momentary outages for the specific facilities comprising the high voltage transmission system near the Bruce area is fewer than 0.58 per circuit per year, and the number of sustained outages range from zero to .6218 per circuit per year. The average duration of outages per year is less than 5.7 hours per year on all but circuits B560V and B561M (the existing Bruce-Milton and Bruce-Claireville circuits) on which the average circuit unavailabilities are 74.7873 hours per year and 35.1128 hours per year, respectively. See Exhibit No. 18, Hydro One's response to Pollution Probe Interrogatory #18, List 2.

43. These are not data on hours of blackouts or brownouts but are data indicating the probability or rates at which a single circuit will experience an unscheduled contingency outage. Such contingencies are events which all transmission systems are designed to withstand. That is, a fundamental transmission planning criterion is that the system must withstand the loss of each single system facility (line, generator or transformer) without overloading the remaining system elements (lines and transformers), without unduly depressing or elevating voltage levels and without causing instability. That is, after each and every loss (or contingency) of a single system element, all remaining equipment must stay within specified ratings and voltage limits, and the system must remain stable. Industry operating reliability criteria (and some planning criteria) allow firm load to be shed after the second contingency outage of both circuits on a double-circuit

line, an event which – as the Hydro One data indicate - is even more improbable than a single contingency.

44. Exhibit No. 16 indicates that only two momentary outages and one sustained outage of both circuits on the existing Bruce-Milton line have occurred since January 1990. However, the narrative accompanying the data indicates that all data may be related to a single event on September 15, 1998. In response to Energy Probe #10 (c), List 2 (Exhibit No. 19), Hydro One failed to provide data but indicated that "the contingency conditions that have been reviewed in the SIA Report [outage of both lines on a double circuit 500 kV tower] **occur very rarely** . . . ." [Emphasis added] The very low probability associated with the design contingency event supports the engineering judgment which led Ontario Hydro to operate a 4-Bruce-Unit generation rejection SPS for the years 1985 through 1998.

45. Hydro One's response to Pollution Probe Interrogatory #46, List 4 (Exhibit No. 20) supports the idea that generation rejection has not been of significance in the past:

> Although the arming of Bruce units for generation rejection has been the rule rather than the exception in the recent past, the occurrences of contingencies that trigger generation rejection are relatively uncommon. Most of the time, the most limiting contingency for the Bruce Complex is the loss of the Bruce-Milton-Claireville line. This contingency last occurred May 31, 1985 as a result of damaging tornados that swept across Central Ontario. The Bruce Special Protection System tripped Bruce units G1, G3 and G5 (net 2175 MW) and 737 MW of pre-selected customer load. Primary demand at this time was 14234 MW.

This response acknowledges that transmission outages of the 500 kV transmission lines are very rare, which undermines Hydro One's and OPA's fundamental assertion that the alternatives (i.e., enhancements to the existing line) are less desirable than a new additional line. In its application, Hydro One implies that a new transmission line would increase reliability by reducing the incidence of transmission failure from the Bruce area. In so doing, it downplays the benefits of alternatives to the proposed new lines by appeal to the amount of undeliverable energy that will allegedly be trapped when transmission capacity is lacking. However, as the facts indicate, transmission outages of 500 kV facilities are extremely rare, and the sustained loss of the most critical contingency (the double circuit loss of Bruce-Milton and Bruce-Milton-Claireville) has only occurred once, back in 1985. A momentary loss of both circuits occurred in 1998.

46. Furthermore, the IESO has alluded to the notion of rejecting wind generation in place of, or in combination with, rejection of a Bruce unit. Indeed, wind generation lends itself to fast backdowns and/or rejection on those occasions when transmission outages suddenly limit Hydro One's transmission capability. Clearly, wind generation can be backed down or rejected in more finely tuned megawatt blocks (1.5 MW per wind machine or whole wind projects (of 40-100 MW)) than can nuclear generation (700+ MW per nuclear generating unit), and such backdowns and rejections of wind generation pose fewer risks and costs than do those associated with nuclear generation. In my opinion, the IESO's plan to add rejection of wind generation as part of an SPS arrangement in the Bruce area is sound and could be usefully implemented.

47. Not only has generation rejection been of low historical significance from a system reliability perspective, but also the practice can continue in full compliance with applicable regulatory criteria. That is, current regulatory criteria permit the continued operation of the existing generation rejection scheme at Bruce NGS. Ontario Resource and Transmission Assessment Criteria, Issue 5.0, IMO_REQ_0041[4] (excerpts in Exhibit No. 21) states [emphasis added]:

> **3.4 Permissible Control Actions**
>
> Following the occurrence of a contingency, the following control actions may be used to respect the loading, voltage decline, and stability limits referenced in this document:

[4] Full document available at: http://www.ieso.ca/imoweb/pubs/marketAdmin/IMO_REQ_0041_TransmissionAssessmentCriteria.pdf

- Generation Redispatch
- **<u>Automatic tripping of generation (generation rejection)</u>**

. . . .

3.4.1 Special Protection System

. . . .

Automatic Tripping of Generation (Generation Rejection)

<u>Automatic tripping of generation via Generation Rejection Schemes (G/R) is an acceptable post-contingency response in limited circumstances</u> as specified below in section 7.3, Control Action Criteria. Arming of G/R may be acceptable for selected contingencies provided the G/R corrects a *security* violation and results in an acceptable operating mode.

The referenced Section 7.3 of the Assessment Criteria states:

7.3 Control Action Criteria

The deployment of control actions and *special protection systems* must not result in material adverse effects on the bulk system.

. . . .

The reliance upon a *special protection system* must be reserved only for exceptional circumstances, such as to provide protection for infrequent contingencies, temporary conditions such as project delays, unusual combinations of system *demand* and *outages*, or to preserve system integrity in the event of severe outages or extreme contingencies.

Transmission expansion plans for areas that may have a material adverse effect on the interconnected bulk power system must not rely on *NPCC* Type I *special protection systems* with all planned transmission facilities in service.

The present situation with respect to transmission facilities emanating from the Bruce Complex qualifies for reliance upon SPS on several of the accounts enumerated in Section 7.3. The loss of both circuits on a double circuit 500 kV line is an infrequent contingency. Moreover, the Province-wide shutdown of coal-fired generation over a relatively short period of time represents an exceptional circumstance. However, under my proposed alternative, the GR necessary in combination with series capacitors would be limited to the rejection of no more than two Bruce units.

48. Previously existing SPSs (such as those allowing as many as four Bruce units to be rejected) may continue to be relied upon under NPCC rules. Although the GR used historically by Ontario relied upon rejecting up to four Bruce Units and shedding 1500 MW of load, my proposed alternative requires no load shedding and rejection of only one Bruce Unit plus 400 MW of wind generation. When asked about its past and current submissions to NPCC with respect to SPS and generation rejection, Hydro One represented in its interrogatory response that its prior submissions to NPCC were not available because they occurred more than 20 years ago (See Exhibit No. 22). An additional excerpt from the submissions was provided after further requests. From this limited information, it is clear that information regarding Hydro One's proposed changes to its SPS is highly relevant in this matter and the Board's inquiry. Furthermore, it appears that Hydro One is planning to continue the use of an SPS arrangement at Bruce even in the event it is allowed to build its proposed Bruce-Milton Lines.

49. Hydro One's right to grandfather existing SPS is provided for in NPCC Regional Reliability Reference Directory #7, Special Protection Systems, December 7, 2007 (see Exhibit No. 2), which provides:

> 1.6.2.2 Existing Facilities
>
> . . . .
>
> a. Planned Renewal or Upgrade to Existing Facilities. It is recognized that there may be SPSs, which existed prior to each TO's, GO's and DP's adoption of *Special Protection System Criteria* that do not meet these criteria. If any **Special Protection Systems** or sub-systems of these facilities are replaced as part of a planned renewal or upgrade to the facility and do not meet all of these criteria, then an assessment

shall be conducted for those criteria that are not met. The result of this assessment shall be reported on TFSP Form #1-5.

50. Much of the relevant information on prior and proposed SPSs should have been included in those submissions to NPCC. Section 2.0 of these criteria, produced below, indicate that Hydro One and/or OPA have been in the past, and are in the future, required to submit substantial information to NPCC that is highly relevant to the engineering matters at issue in this proceeding. Nonetheless, Hydro One declined to provide that information.

51. NPCC Regional Reliability Reference Directory #7 provides:

NPCC Reliability Reference Directory #7, Appendix B
Procedure for Review of Special Protection Systems

Introduction

This Appendix provides the procedure to follow to obtain concurrence from NPCC if an entity concludes that a new **Special Protection System** or a modification of an existing **Special Protection System** will be required which affects the **bulk power system**. The procedure is also shown on the attached flow chart.

2.0 NPCC Review and Concurrence

2.1 Allowing for sufficient lead time to ensure an orderly review, the entity will notify the chairman of the Task Force on Coordination of Planning (TFCP) of its proposal to install a new **Special Protection System** or modify an existing **Special Protection System**. The entity will send copies of the complete notification to TFCO and TFSP. This notification will include statements that describe possible failure modes and whether misoperation, unintended operation or failure of the **Special Protection System** would have local, inter-company, inter-**Area** or inter-Regional consequences, when the **Special Protection System** is planned for service, how long it is expected to remain in service, the specific **contingency**(s) for which it is designed to operate and whether the **Special Protection System** will be designed according to the NPCC *Bulk Power System Protection Criteria* (Document A-5) and the *Special Protection System Criteria* and Standards requirements listed in this docment (sic).

See Exhibit No. 2. These criteria make clear that generation rejection remains a Permissible Control Action under the limited circumstances specified in Section 7.3. As noted, the present situation with respect to transmission facilities emanating from the Bruce Complex qualifies as an exceptional circumstance for reliance upon SPS on several of the accounts enumerated in Section 7.3. The loss of both circuits on a double circuit 500 kV line is an infrequent contingency. Moreover, the Province-wide shutdown of coal-fired generation over a relatively short period of time represents an exceptional circumstance.

52. Under applicable reliability criteria, the Ontario bulk power system is permitted to engage in generation rejection in amounts greater than those now deemed acceptable by Hydro One under applicable reliability criteria. This self-imposed limit on generation rejection appears to be justified by Hydro One on the basis of an undocumented IESO-NPCC commitment governing interconnections with New York and Michigan. Hydro One's responses to interrogatories indicate that that commitment limits imports to 1500 MW immediately following a contingency outage event. See Exhibit Nos. 20 and 23 (Hydro One's responses to Pollution Probe Interrogatories #46 and #39) and Exhibit 24 (Hydro One's response to Saugeen Ojibway Nations Interrogatory #9). Hydro One has not provided copies of the governing agreements, made clear what the parameters of that contractual limit are or why that limit cannot be lifted by operating additional amounts of fast-responding spinning reserve (e.g., from spinning-but-unloaded hydro generation that typically can ramp to full load in a matter of seconds or automatic industrial load shedding).

53. In Exhibit No. 10, Hydro One cites the April 11, 2006, series capacitor study (Exhibit No. 12) and reaffirms its finding that the existing system with series capacitors and the near term measures would be "capable of accommodating" the output of seven nuclear units plus 675 MW of wind in the Bruce area without generation rejection. The choice of language ("capable of accommodating") does not state that the limit is the output of seven nuclear units plus 675 MW of wind,

or what the actual limit is. In other words, the existing system with series capacitors and near term measures would accommodate 6325 MW (3 Bruce A units at 750 MW each plus four Bruce B units at 850 MW each plus 675 MW of wind).

54. The response to Saugeen Ojibway Nations Interrogatory #10, Exhibit No. 10, goes on to state that the maximum amount of generation rejection "permissible" is the output of one nuclear unit "and up to 400 MW of wind" when including the post-contingency loss increase. This is consistent with Hydro One's contention that it has agreed to limit imports after a contingency to 1500 MW (a 750 MW nuclear unit, plus 400 MW wind, plus 350 MW in incremental losses = 1500 MW).

55. Combining the data in both parts of the response makes it clear that, with series capacitors and generation rejection, Hydro One will have the ability to transmit at least 7475 MW, equal to the output of eight nuclear units plus wind generation in excess of the 700 MW existing and committed wind generation (i.e., delivery of 1075 MW of wind can be achieved - seven Bruce units plus 675 MW of wind (6325 MW) plus the eighth, rejectable, Bruce unit at 750 MW plus 400 MW of rejectable wind). These data indicate, after rejecting one Bruce unit and 400 MW wind, the output of the Bruce NGS and wind generation in the vicinity of Bruce would drop down to that of seven nuclear units plus 675 MW of wind (that can be handled by the existing transmission system supplemented with series capacitors plus interim measures).

56. It is clear, based upon the information provided in the various studies by the IESO and others that the installation of series capacitors and a continuation of the current practice of generation rejection (albeit rejecting only 1 Bruce unit and some wind generation rather than the previous SPS that could reject up to 4 Bruce units along with dropping load) is a reliable and far more cost effective and economically efficient alternative to the project proposed by Hydro One. Further,

this alternative is scalable to meet the future possibility of increased or decreased generation in the Bruce area. In contrast, Hydro One's proposal is to build a substantial amount of excess transmission capacity well before generation facilities that would load up that transmission capacity are approved or constructed, and that transmission capacity could not be scaled down in response to any decrease in the need for generation from the Bruce area.

Project Need and Justification – Firm Transmission Capacity Not Needed for Wind

57. The Hydro One application and the OPA work leading up to the filing is based upon a plan to build enough redundancy into its system to provide firm transmission capacity to deliver 100% of the committed and planned wind generation. Such a plan will produce surplus transmission capability and would not protect the interests of consumers or promote economic efficiency or cost effectiveness.

58. Firm transmission is the amount that can be delivered after the loss of the most critical load serving facility (generation, transmission line or transformer). In this case, Hydro One defines the most critical contingency as the loss of not just one line, but two lines – both of the existing double circuit 500 kV lines from Bruce to Milton. However, it is rare for multiple 500 kV lines to experience simultaneous outages. Moreover, it is rare for all wind generators to be generating at their peak capacity at the same time. One must also consider that wind generation may be at its peak output during periods of low system demand (i.e., daily and seasonal off-peak periods) and therefore logically should have little economic impact in terms of driving transmission upgrades. It is both contrary to principles of sound transmission planning and economically imprudent to expend $635 million on transmission facilities capable of delivering 1700 MW of wind generation on a firm basis when significantly more than the existing and committed 700 MW of wind generation can be delivered on a nearly firm basis at a cost of $97 million.

59. Hydro One does not need firm transmission capability in order to deliver existing and committed wind generation from the Bruce region. Nor would firm transmission capability be required if additional wind generation from the region were to be approved in the future. Wind generation is intermittent, and not all wind turbines will be in operation even if wind velocities are sufficient to produce power. In recognition of wind generation's intermittent nature, Hydro One's policy is to rely only upon 20% or 1/5th of its installed wind capacity as a firm generating resource in planning to meet future peak demands. See Exhibit No. 25, the response to Saugeen Ojibway Nations Interrogatory #18 List 1. Even if the full 1700 MW of potential wind generation in the Bruce region identified in the IPSP were approved, developed and contracted for, its firm component would be only 340 MW. In fact, series capacitors and generation rejection can provide transmission capability for an additional 375 MW of wind generation in excess of the currently installed and committed generation, assuming that 400 MW of wind generation (and one Bruce Unit) would be rejected in the event Hydro One experiences its most critical contingency. In addition, capacity equal to the output of only 7 of the 8 Bruce Units are expected to operate on average, based upon outages, leaving line capacity available for transmitting 1825 MW, 125 MW more than the entire 1700 MW of committed and potential wind generation (equal to 1075 MW that can be rejected plus the average amount of transmission capacity devoted to Bruce that, on average, remains unused - 750 MW).

60. On a day-to-day basis, Hydro One and the IESO could determine what amount of wind generation could be accommodated. On most occasions, the amount that could be accommodated should significantly exceed 700 MW of wind generation in addition to the output of eight Bruce nuclear units, all of which could be transmitted using series capacitors and GR. And, as noted previously, because 500 kV transmission outages are rare, all of the committed and most, if not all, of the potential wind generation should be transmittable by use of non-firm transmission capacity. Because wind generation can decline quickly, the IESO

can be expected to carry operating reserves at least equal to the amount of wind generation which is at risk of being lost when winds die down.

61. Relying upon transmission capability that is rarely unavailable for delivery of intermittent wind energy would cause relatively little wind energy production to be lost, especially when one considers that the eight nuclear units are unlikely to all be on, and at full output, at the same time for very many hours per year. Their average availability is 85%. See Exhibit No. 26, Hydro One's response to Energy Probe Interrogatory #3, List 1. Hydro One takes the position that providing transmission service to wind generation that is rarely unavailable "would be employing generation rejection for normal operation, which is not consistent with the applicable planning standards (please see the response to OEB Interrogatory 3.2)." See Hydro One's response to Saugeen Ojibway Nations Interrogatory #15, List 1, Exhibit No. 27. However, rejecting generation from an intermittent source such as wind generation on the rare occasions that all nuclear units and all wind units are operating at full capacity would be consistent with prudent planning, would have a relatively negligible effect upon bulk power reliability, and would be most economically efficient and cost effective.

62. Furthermore, when the wind is strong, it cools transmission line conductors, enabling utilities to increase the ratings of transmission lines in the vicinity of the wind generators. Technical means exist to continuously monitor sag in line conductors and the velocity of the wind (as well as ambient temperature and sunlight levels) and to adjust the ratings of transmission lines in real time. This practice is known as dynamic rating. One of the world's seminal minds and equipment developers on this topic is Mr. Tapani Seppa who has found that use of dynamic ratings would allow utilities to assign up to 30% higher ratings on many circuits for up to 98% of the time. See Exhibit No. 28.

63. In its analysis of the feasibility of series capacitors, the IESO has accepted a limited version of that design practice with respect to its 230 kV lines B4V and

B5V within 50 km of the Amaranth wind generation by adopting a static rating based on a wind velocity of 15 km/Hr as compared to its usual ratings based on a wind velocity of 4 km/Hr. However,

> Hydro One has not conducted any studies of the correlation between the wind velocities in the vicinity of committed and potential wind [generation] in the Bruce area with the wind velocities along any transmission corridor.

See the response to Saugeen Ojibway Nations Interrogatory #14(a) and (b) in Exhibit No. 29. In response to subpart 14(c), Hydro One states:

> For the actual day-to-day operation of the transmission system, the IESO receives "dynamic" ratings from Hydro One at 5 minute intervals that recognize both the local ambient temperatures and the prevailing wind speeds, while also allowing for the solar conditions and the actual pre-contingency loadings on the circuits. With this latest information, the IESO is then able to maximize the use of the available transfer capability.

Overall, because of Hydro One's failure to provide requested supporting documentation, it is not possible to determine whether Hydro One has adequately considered dynamic ratings as a part of a reasonable alternative to its proposed project. It has not been possible to determine the extent of Hydro One's current monitoring or whether more could be done to reflect wind velocities in assigning ratings to transmission lines for planning and design purposes as well as for purposes of operations. Further, other data suggest that more can, in fact, be done (e.g., IESO's occasional use of static ratings based on a single higher wind velocity as opposed to statistical data taken from dynamic ratings).

64. It is important to recognize that the use of dynamic ratings affects thermal ratings but does not affect the impedance of transmission lines. It is the impedance and associated angular stability limit of a network which often dictate the network's transfer capability. E.g., the angular stability limit can be increased by lowering a network's impedance through use of series capacitors, new conductors, or new

parallel lines. Accordingly, where transfer capabilities can be limited by angular stability or voltage stability as well as by thermal capability (as is the case in the vicinity of Bruce), increasing a line's thermal rating by use of dynamic rating techniques will not necessarily be helpful. Nevertheless, the IESO did determine that increased thermal ratings on several 500 kV and 230 kV transmission lines attributable to higher assumed wind velocities of 15 km/hour did increase transfer capabilities achievable through use of series capacitors on the Bruce-Longwood-Nanticoke-Middleport 500 kV segments of the path between Bruce and the GTA. See Exhibit No. 12 at 6. With thermal limits taken care of, there are many ways to raise stability limits.

65. For Hydro One to build firm transmission capability in excess of 1700 MW in order to serve 700 MW of wind is contrary to sound system design principles. Further, it is neither cost effective nor economically prudent to do so, as the transmission cost of units of wind generation will be excessively high. Instead, economic prudence and cost effective design dictate that Hydro One should construct transmission capability for no more than the existing and committed wind generation of 700 MW. Further, if new wind generation from the area is approved and contracted for in the future, Hydro One should consider whether to enhance the transmission infrastructure or whether the pre-existing infrastructure has enough capacity to deliver all but a small portion of the available wind production. I expect an objective engineering analysis seeking to protect the interests of consumers, and to determine whether proposed actions promote efficiency and reliability, would result in a decision not to build transmission capacity sufficient to deliver the full installed capability of all committed and projected wind generation because that full amount would be used only very rarely.

Project Alternatives – Cost Benefit Comparison

66. Hydro One has supplied several responses to interrogatories that purport to evaluate the relative costs of the proposed Bruce-Milton Lines and two alternatives. In particular, there were a series of responses to interrogatories propounded by Pollution Probe, Energy Probe, and the Ontario Energy Board (Board Staff). In these replies, Hydro One indicated that it believed that an appropriate measure of determining a reasonable quantification of the comparative economics could be based upon a comparison of the Capital Costs, Costs of Undelivered Energy and Costs of Losses that would be anticipated to result under the alternative assumptions. However, in the information provided in prefiled evidence and in response to interrogatories, Hydro One has (1) failed to provide critical data, (2) has provided insufficient data in a number of key areas, (3) has applied a questionable methodology, (4) has improperly included various unapproved generation sources in its analysis, and (5) has failed to consider various factors that will have a significant impact on the economic analysis. As a result, the overall reliability of Hydro One's economic comparison of the project and its reasonable alternatives ought not to be accepted.

67. First, and most importantly, Hydro One has declined to provide the detailed workpapers and computer models that were used to quantify the costs of undelivered energy and losses. See Exhibit No. 30, the response to Pollution Probe Interrogatory #47, List 5, subpart a. Hydro One admits "initially, the proposed Bruce to Milton line has the highest cost due to its larger upfront capital costs." It is only when "the costs of the increased undelivered energy and losses " from alternatives are included that Hydro One reaches its conclusion that the Bruce-Milton Line is "less expensive in the long-run." See Exhibit No. 31, response to Energy Probe Interrogatory #29, List 4. Hydro One's withholding of key workpapers frustrates attempts to validate Hydro One's analysis and prevents critical evidence from coming before the Board in the matter.

68. Second, Hydro One has elected to provide generic verbal descriptions of the modeling procedures and data inputs that were utilized in its analysis, some representative graphical depictions of intermediate modeling results and tabular summaries of the modeling output. See, for example, Exhibit No. 32, response to Pollution Probe Interrogatory # 9, as well as Exhibit Nos. 30 and 31. Even these limited insights into the process have been provided in a piecemeal fashion in response to numerous interrogatories. Based on the evidence that is on record in this matter, Hydro One's responses provide a superficial treatment of what appears to be a very complex modeling effort. Under industry custom and practice, Hydro One would maintain documentation for its modeling efforts that are employed by those staff responsible for conducting the analysis. It therefore could and should have been provided.

69. In addition, Hydro One does not provide the data employed in its determinations of "capability reduction" on lines leading out of the Bruce area. See Exhibit No. 30, response to Pollution Probe Interrogatory #47, List 5. I am therefore unable to determine the appropriateness of the capacity deratings employed in the model or the suitability of such derating assumptions. Hydro One makes references to "equipment outages" but makes no mention of whether these outages were planned or forced or whether the planned outages in the model reflect planning schedules uniquely associated with the new Bruce-Milton Lines.

70. Third, in addition to my concern with the lack of proper support for the conclusions reached by Hydro One, I have other concerns with the studies. First, the determination of undelivered energy savings attributable to the construction of the Bruce-Milton Lines should not have been based on the assumption that uncommitted "future wind" will materialize. Whether such wind will be developed is uncertain, but, if the construction of the Bruce-Milton Lines is approved, the capital cost of the line is absolutely certain. Some wind projects that had previously been approved were ultimately not developed. Therefore, the analysis performed by Hydro One should exclude contributions of uncommitted

wind generators to the purported economic benefits of the Bruce-Milton Lines or, at a minimum, should discount the assumed benefits in order to reflect their uncertainty.

71. Fourth, as I have described earlier, Hydro One bases its economic analysis on the assumption that the Bruce B units will be refurbished, beginning in 2018. The analysis assumes that one unit will be out of service during the years following 2018 until all four units are back to their full output in January of 2024. See Exhibit No. 30, Attachment A. This assumption, like that of the uncommitted 1000 MW of wind capacity, should not be included in the economic analysis.

72. Despite Hydro One's cryptic description of its methodology, adjusting benefits for uncertainty can be expected to have a significant impact. Although the wind energy from uncommitted wind generation is less than 5% of the total energy presumed to be available for transmission from Bruce to Ontario loads, it does amount to roughly an average of 280 MW per hour on an annual basis. In 2012 the cost of undelivered energy ($3 million) is projected by Hydro One to be relatively small --this is for a period during which no new wind generation was assumed to have been added. See Exhibit No. 32, response to Pollution Probe Interrogatory #9, List 1. In 2013 the cost of undelivered energy increases to $69 million, which suggests that Hydro One is assuming that the uncommitted but potential installations of future wind generation will begin to start generating in 2013 or that all 8 Bruce Units are available by then. The costs of undelivered energy for 2013 and 2014 continue to rise, perhaps as a result of assuming that more future potential wind generation will be interconnected. After this point, the costs begin to decline, which is attributable to the use of present value discounting. Beginning in 2018, about the time at which Hydro One assumes that the Bruce B units will begin their refurbishment, the value of undeliverable energy is very low, a level that continues until such time as the Bruce B refurbishment is projected to be complete. Thereafter, the value of undeliverable energy again is projected to become significant. See Exhibit No. 32, response to

Pollution Probe Interrogatory #9, List 1. From this pattern, it appears that excluding the uncommitted future wind generation and the unapproved refurbishment of Bruce B would result in significant reductions in Hydro One's estimate of undelivered energy costs.

73. Fifth, Hydro One may or may not have considered the following factors, which could have an impact on an accurate economic analysis of various alternatives.

A. Hydro One included the effect of changes in losses. However, there is no discussion of how the loss calculation is affected by the undeliverable energy calculation. From the limited description provided, I am unable to tell whether Hydro One is valuing losses on energy that it models as being undeliverable. Such double counting would inflate the estimate of the purported cost of the alternative transmission options.

B. Another factor involves the description of the assumed availability of the Bruce generation units, which is too cursory to allow me to determine its appropriateness. Hydro One has included a sensitivity assessment of this latter issue by including an assumption of a 10% lower availability of the Bruce units. See Exhibit No 32, response to Pollution Probe Interrogatory #9, subpart (e).

C. Hydro One's analysis assumes that the amount of energy that could be delivered by use of series capacitors plus GR is 7076 MW. Based on my analysis, it is more appropriate to base the comparison on a capacity of 7475 MW, which would make this alternative more attractive from a cost benefit perspective.

D. Hydro One has failed to take account of the increased costs associated with remedying the "circulating loop flow" problem that will be caused or exacerbated by its proposal. Remedial action, likely involving the installation of costly phase shifting devices, will have a significant effect on the cost benefit comparison of the various alternatives.

E. Finally, Hydro One makes no mention of the use of dynamic ratings on the transmission lines. Although Hydro One has acknowledged that the use of dynamic ratings may be appropriate, the undeliverable energy analysis does not seem to have employed this technique to allow the use of the transmission system to deliver the energy. Ignoring the benefits of dynamic ratings would overstate the amount of energy that is considered to be undeliverable.

These concerns lead me to believe that Hydro One's projection of undeliverable energy is probably excessive and that the Board should not rely upon Hydro One's studies.

74. In summary, there are a number of very serious concerns about the appropriateness and reliability of Hydro One's economic analysis comparing its proposed project to the reasonable alternatives. Hydro One has failed to provide intervenors or the Board, through its prefiled evidence, with sufficient data to validate its analysis or assess its credibility. As a result, the Board should not accept the conclusions of Hydro One's economic analysis as presented.

75. This concludes my affidavit.

IN THE MATTER OF the *Ontario Energy Board Act*, 1998, S.O. 1998, C.15 (Sched. B);

AND IN THE MATTER OF an Application by Hydro One Networks Inc. pursuant to section 92 of the Act, for an Order or Orders granting leave to construct a transmission reinforcement project between the Bruce Power Facility and Milton Switching Station, all in the Province of Ontario.

AFFIDAVIT

of

WHITFIELD A. RUSSELL

on behalf of

THE SAUGEEN OJIBWAY NATIONS

I, Whitfield A. Russell, certify that the attached Affidavit and Exhibits on behalf of the Saugeen Ojibway Nations, which bears my name, were prepared by me or under my direct supervision and are true and accurate to the best of my knowledge and belief formed after a reasonable inquiry.

Whitfield A. Russell

Whitfield A. Russell

Subscribed and sworn to before me this 18th day of April, 2008, by Whitfield A. Russell.

City of Alexandria
Commonwealth of Virginia

Notary Public: Tara K. Parker-Johnson

Notary registration Number: 333663

My Commission Expires: November 30, 2011

TARA K. PARKER-JOHNSON
Notary Public
Commonwealth of Virginia
333663
My Commission Expires Nov 30, 2011

Exhibit No. 1

WHITFIELD A. RUSSELL

Whitfield A. Russell is an electrical engineer, attorney and President of Whitfield A. Russell and Associates, P.C., a corporate Partner of Whitfield Russell Associates. He holds a Bachelor of Science degree in Electrical Engineering from the University of Maine at Orono, a Master of Science in Electrical Engineering from the University of Maryland, and a Juris Doctor degree from Georgetown University Law Center.

Mr. Russell is experienced in electric utility system planning (transmission and generation), ratemaking and bulk power contracts. He has been qualified as an expert witness in 27 states (as well as in the Provinces of Alberta and Manitoba and the District of Columbia) and has been accepted as an expert in approximately 150 proceedings before state and federal courts, arbitration panels, public service commissions, the Federal Energy Regulatory Commission and numerous other administrative agencies. Mr. Russell's clients have included public power utilities, state and federal power marketing agencies, investor-owned utilities, independent power producers, and state regulatory bodies and their staffs. He has written and spoken extensively on matters relating to regulated electric utilities.

Mr. Russell founded Whitfield Russell Associates in 1976.[1] Prior to that, from 1972 to 1976, he served as Engineer and eventually Chief Engineer for the Securities and Exchange Commission's Division of Corporate Regulation. That Division, in administering the Public Utility Holding Company Act of 1935, regulated registered pubic utility holding company systems representing approximately 20% of the gas and electric industries in the United States.

From 1971 to 1972, Mr. Russell was on the staff of the Federal Power Commission. He served as a consultant to staff attorneys in proceedings, and as an expert witness in an administrative proceeding before the Atomic Energy Commission.

From 1969 to 1971, Mr. Russell served as an Associate Engineer in the System Planning Division of the Potomac Electric Power Company. At PEPCO, he conducted system studies of load flows and stability. He was also a member of numerous study groups concerned with planning and operation of the Pennsylvania-New Jersey-Maryland Interconnection.

[1] Whitfield Russell Associates is located at 4232 King Street Alexandria, VA 22302. (703) 894-2200

PROCEEDINGS IN WHICH
WHITFIELD A. RUSSELL
HAS TESTIFIED

1. Anaheim v. Kleppe, U.S. District Court, Arizona (Civil No. 74-542 PHX-WEC), concerning the availability of transmission capacity in the Pacific Southwest.

2. In re: Potomac Electric Power Company, before the Maryland Public Service Commission, Case No. 7004, concerning the need for proposed 500 kV transmission lines in the Washington, D.C. area.

3. In re: Baltimore Gas and Electric Company, and Potomac Electric Power Company, before the Maryland Public Service Commission, Case No. 6984, involving the same transmission lines mentioned in the preceding case.

4. Perry v. The City of Monroe, Louisiana (State of Louisiana, Parish of Ouachita, Fourth District Court; Nos. 111145, 111146, 111147) regarding the necessity of Monroe's disposing of its municipal utility system; August 16, 1977.

5. In re: Potomac Electric Power Company, before the District of Columbia Public Service Commission, in Case No. 685, concerning the system planning of the Potomac Electric Power Company and the PJM Pool.

6. In re: Generic Hearings on Rate Structure, before the Colorado Public Utilities Commission, Case No. 5693, regarding the engineering aspects of marginal cost pricing and power pooling in Colorado; October 1980.

7. In re: Pacific Gas and Electric Company, FERC Docket No. ER76-532, regarding the proper level of rates to be charged by PG&E to the Central Valley Project for transmission service; April 1978, revised January 1979.

8. In re: Pacific Power and Light Company, FERC Docket No. E-7796, regarding the Seven Party Agreement and related matters; May 1978.

9. In re: Pacific Gas and Electric Company, FERC Docket No. E-7777 (II), concerning the provisions of numerous bulk power arrangements governing electric utilities in California; October 1978.

10. In re: Potomac Edison Company, before the Maryland Public Service Commission, Case No. 7055, concerning the need for a 230 kV transmission line in Montgomery County, Maryland.

11. In re: Delmarva Power and Light Company, before the Maryland Public Service Commission, Case Nos. 7239F, 7239G, 7239H, 7239I, 7239J, 7239K, 7239L,

7239M and 7239N concerning fuel rate adjustments; June 17, 1980, March 17, 1981, August 19, 1981 and November 20, 1981.

12. In re: Baltimore Gas and Electric Company, before the Maryland Public Service Commission, Case Nos. 7238G, 7238H, 7238I, 7238J, 7238L and combined dockets 7238P, Q, R and S, concerning fuel rates; June 20, 1980, November 2, 1980, April 14, 1981, July 17, 1981 and September 14, 1981.

13. In re: Potomac Electric Power Company, before the Maryland Public Service Commission, Case Nos. 7240A, 7240B, 7240C, 7240D, 7240E, 7240F and 7240G, concerning fuel rate adjustments; October 1980.

14. In re: Florida Power & Light Company, FERC Docket No. E-9574, concerning system planning for the City of Vero Beach, Florida. FP&L withdrew its application to acquire the Vero Beach system.

15. In re: Oklahoma Gas and Electric Company, FERC Docket No. ER77-465, concerning rates for energy banking and transmission services rendered to the Western Farmers Electric Cooperative; October 20, 1978.

16. In re: Idaho Power Company, before the Idaho Public Utility Commission, Case No. U-1006-158, concerning the value of interruptible industrial loads and Idaho Power Companies entitlement to Federal secondary energy; March 1980.

17. In re: Potomac Electric Power Company, before the District of Columbia Public Service Commission, Case No. 737, concerning the Company's construction program; October 27, 1980.

18. In re: Virginia Electric and Power Company, before the Virginia State Corporation Commission, Case No. PUE 800006, concerning construction of transmission lines in the Charlottesville, Virginia area; 1982.

19. In re: Pacific Gas and Electric Company, FERC Project Nos. 2735 and 1988, concerning the Helms Project, a pumped storage generating unit; August 24, 1979.

20. Southeastern Power Administration v. Kentucky Utilities Company, FERC Docket No. EL 80-7, concerning SEPA's attempt to obtain a FERC wheeling order under the Public Utility Regulatory Policies Act of 1978; October 6, 1980.

21. In re: Sierra Pacific Power Company, before the Public Service Commission of Nevada, Docket No. 81-105, concerning construction and transmission planning; June 29, 1981.

22. In re: Virginia Electric and Power Company, before the North Carolina Utilities Commission, Docket No. E-22, Sub 257, concerning production cost simulation and normalized fuel adjustment clause formula; June 9, 1981.

23. In re: the Investigation of the Capital Expansion For Electric Generation, before the New Mexico Public Service Commission, Case No. 1577, concerning construction programs of the Public Service Company of New Mexico and El Paso Electric Company; July 2, 1981.

24. In re: Potomac Edison Company, before the Maryland Public Service Commission, Case Nos. 7241A, 7241B, 7241C and 7241D, concerning fuel rate adjustments and productivity of generating units; March 13, 1981.

25. In re: Potomac Edison Company, before the Maryland Public Service Commission, Case No. 7528, concerning the method of calculating Potomac Edison's fuel rate.

26. In re: Delmarva Power & Light Company, before the Maryland Public Service Commission, Docket No. 7570, concerning transmission loss allocation methodology; October 30, 1981.

27. In re: Nebraska Public Power District, before the South Dakota Public Utilities Commission, Docket No. F-3371, concerning proposed construction and operation of the 500 kV MANDAN Transmission Facility; September 29, 1981.

28. In re: Sierra Pacific Power Company, before the Public Service Commission of Nevada, Docket No. 81-660, concerning construction and transmission planning; January 4, 1981.

29. In re: Kentucky Utilities Company, FERC Docket Nos. ER-81-341-000 and ER81-267-000, concerning construction planning and the market for short term power; February 26, 1982 and May 7, 1982.

30. In re: Kentucky Power Company et al., before the Kentucky Public Service Commission, Case No. 8566, concerning cogeneration and avoided costs; September 16, 1982.

31. In re: Appalachian Power Company, before the West Virginia Public Service Commission, Case No. 82-162-42T, concerning the wholesale market and short-term power sales; October 19, 1982.

32. In re: Central Maine Power Company, before the Maine Public Utility Commission, Docket No. 82-137, concerning the application of Central Maine Power Company to reorganize in the form of a holding company; October 25, 1982.

33. In re: Houston Lighting & Power Company, before the Public Utility Commission of Texas, Docket No. 4712, concerning rates to be paid to cogenerators and small power producers; February 28, 1983.

34. In re: Dow Chemical Company, before the Public Utility Commission of Texas, Docket Nos. 4802, 5050 and 5062, concerning rates for interruptible service; September 26, 1983.

35. In re: Nevada Power Company, before the Nevada Public Service Commission, Docket No. 83-707, concerning the Reid Gardner No. 4 Participation Agreement, October 11, 1983.

36. Dow Chemical Company vs. Houston Lighting & Power Company, before the District Court of Brazoria County, Texas, 149th Judicial District, No. 79-F-2620, regarding the custom and usage of contract terms in the electric utility industry. Live direct testimony in a jury trial. No transcript available.

37. In re: The Montana Power Company and the Confederated Salish and Kootenai Tribes of the Flathead Reservation, Project Nos. 5-004 and 2776-000, concerning the Tribes' intention and ability to sell its output to one or more entities in the Western states, if obtaining the license to the Kerr Project; July 15, 1983.

38. In re: the Dow Chemical Company vs. Gulf States Utilities Company, before the Louisiana Public Service Commission, Docket No. U-16038, concerning cogeneration and small power production; October 28, 1984.

39. In re: Petition of the Dow Chemical Company, before the Public Utility Commission of Texas, Docket No. 5651, for an order compelling Houston Lighting & Power Company to comply with the Commission Order concerning cogeneration and small power production; December 10, 1984.

40. In re: Oklahoma Gas and Electric Company, before the Oklahoma Corporation Commission, Cause No. 29017, concerning priority for recognition of capacity costs to Qualifying Facilities; January 1985.

41. In re: Kansas City Power & Light Company of Kansas City, Missouri, before the Missouri Public Service Commission, Case Nos. ER-85-128 and EO-85-185, regarding rate design and allocation of production-related costs for the Company's Wolf Creek Generating Station on behalf of the United States Department of Energy; May 3, 1985.

42. In re: Kansas City Power and Light Company, before the State Corporation Commission of the state of Kansas, Docket Nos. 142,099-U and 120,924-U, concerning operating problems caused by excess capacity, mitigation measures and regulatory requirements, on behalf of Johnson County Joint Intervenors; May 6, 1985.

43. In re: Duke Power Company, before the North Carolina Utilities Commission, Docket No. E-7, Sub 391, concerning the Company's use of an Extended Cold Shutdown program to mitigate its excess capacity situation resulting from the

Catawba Units, on behalf of the Department of Justice for the State of North Carolina; June 26, 1985.

44. Sierra Pacific Power Company, before the Public Service Commission of the State of Nevada, Docket No. 85-430, on behalf of the State of Nevada Attorney General's Office of Advocate for Customers of Public Utilities, concerning the effects upon retail rates of placing Valmy Unit No. 2 in service; August 26, 1985.

45. United States of America Department of Energy, before the Bonneville Power Administration, on behalf of the City of Vernon, California, concerning the 1985 Proposed Firm Displacement Power Rate; November 8, 1985.

46. In re: City of Anaheim, et al., v. Southern California Edison, Docket No. 78-0810, on behalf of five partial requirements wholesale customers of Southern California Edison Company, making claims under Federal antitrust laws for access to the Pacific Northwest-Pacific Southwest Intertie.

47. In the Matter of the Application of Sierra Pacific Power Company for Approval of its 1986-2006 Electric Resource Plan, Docket No. 86-701, on behalf of the State of Nevada Attorney General's Office of Advocate for Customers of Public Utilities, concerning efforts of Sierra Pacific Power Company to develop a new interconnection (the SMUD Tie) with the Sacramento Municipal Utility District; September 8, 1986.

48. The Federal Executive Agencies, Complainant v. Public Service Company of Colorado, before the Public Utilities Commission of the State of Colorado, Case No. 6551, on behalf of the Federal Executive Agencies concerning the feasibility of wheeling federal preference power to the Government's facilities at Rocky Flats, the Lowry Air Force Base, the Rocky Flats Technical Center and the Denver Federal Center; December 15, 1986 and February 10, 1987.

49. Commonwealth Edison Company, before the State of Illinois, Illinois Commerce Commission, Docket Nos. 87-0043, 87-0044 and 87-0057 Consolidated, on behalf of Intervenor, Citizen's Utility Board of Illinois, concerning Edison's proposal to form a generating subsidiary.

50. Nevada Power Company, before the Nevada Public Service Commission, Docket No. 87-750, concerning a 345 kV transmission line proposed to connect Nevada Power Company to Utah Power and Light Company; September 28, 1987, October 8, 1987 and October 24, 1987.

51. Utah Power & Light Company, PacifiCorp, PC/UP&L Merging Corporation, FERC Docket No. EC88-2-000, establishing conditions for the proposed merger; also challenging PP&L's/UP&L's assertion that the claimed coordination benefits would not be attainable through power pooling or by contract; February 12, 1988.

52. Rosemount Cogeneration Joint Venture, Biosyn Chemical Corporation and Oxbow Power Corporation vs. Northern States Power Company, before the Minnesota Public Utilities Commission, Docket No. E-002/GG-88-491, on behalf of Petitioners, Rosemount Cogeneration Joint Venture, Biosyn Chemical Corporation and Oxbow Power Corporation, concerning a contract between Northern States Power and Biosyn Chemical Corporation covering the 50 MW output of a yet-to-be-constructed power plant based on the forecast costs of Sherburne County Unit #3 ("Sherco Unit 3"); October 24, 1988.

53. In re: Potomac Electric Power Company, before the District of Columbia Public Service Commission, Case No. 869, on behalf of the District of Columbia Office of the People's Counsel, concerning the prudence of off-system purchases; June 6, 1988.

54. In re: Wisconsin Public Power Inc. System, Advance Plan 5, before the Public Service Commission of the state of Wisconsin, on behalf of the Wisconsin Public Power System, Inc., concerning transmission planning in the state of Wisconsin; August 15, 1988.

55. In re: Nevada Power Company, before the Public Service Commission of Nevada, Docket No. 88-701, on behalf of the Attorney General's Office of Advocate for Customers of Public Utilities, concerning NPC's 1988 Resource Plan; August 29, 1988.

56. In re: Commonwealth Edison Company, before the Illinois Commerce Commission, Docket Nos. 87-0427, 87-0169, 88-0189 and 88-0219, on behalf of the Citizens Utility Board, concerning rejection of an unfair, Staff-proposed rate order; September 12, 1988.

57. In re: Dow Chemical Company vs. Houston Lighting & Power Company, before the Texas Public Utilities Commission, Docket No. 8425, 8431, on behalf of The Dow Chemical Company, concerning application of Houston Lighting & Power Company for authority to change rates; Fuel Reconciliation, Revenue Requirements and Rate Design; March 15, 1989.

58. Dow Chemical Company vs. Houston Lighting & Power Company, before the Texas Public Utilities Commission, Docket No. 8555, on behalf of The Dow Chemical Company, concerning rate discrimination, cost to serve and class load characteristics; August 7, 1989.

59. In re: Sierra Pacific Power Company, before the Public Service Commission of Nevada, Docket No. 89-676, on behalf of the Attorney General's Office of Advocate for Customers of Public Utilities, concerning Sierra's system planning; August 18, 1989.

60. <u>In re: Northern California Power Agency vs. Pacific Gas and Electric Company</u>, before the Federal Energy Regulatory Commission, Docket No. EL89-4-000, on behalf of the Northern California Power Agency ("NCPA"), concerning the Interconnection Agreement between Pacific Gas & Electric Company and NCPA; October 3, 1989.

61. <u>In re: M-S-R Public Power Agency vs. Tucson Electric Power Company,</u> before the United States District Court of Arizona, No. CIV-86-521-TUC-ACM, on behalf of M-S-R, concerning TEP's breach of contract.

62. <u>In re: Southern California Edison Company and San Diego Gas & Electric Company</u>, before the Federal Energy Regulatory Commission, Docket No. EC89-5-000, on behalf of the City of Vernon, California concerning expected effects of the proposed merger on competition, system operation and transmission access; January 3, 1990 and March 12, 1990.

63. <u>In re: Farmers Electrical Cooperative Corporation and City Water & Light Plant of the City of Jonesboro, Arkansas, v. Arkansas Power & Light Company</u>, No. LR-C-86-118. Presented deposition testimony on AP&L's liability and assisted in settlement negotiations of treble damage claims for transmission line foreclosure made by plaintiffs, City Water and Light Department of Jonesboro, Arkansas and the Farmers Electric Cooperative.

64. <u>In re: Southern California Edison Company and San Diego Gas & Electric Company</u>, before the California Public Utilities Commission, Docket No. 88-12-035, on behalf of the City of Vernon, California concerning expected effects of the proposed merger on competition, system operation and transmission access; April 1990.

65. <u>In re: Northeast Utilities Service Company and Public Service Company of New Hampshire</u>, before the Federal Energy Regulatory Commission, Docket Nos. EC90-10-000, ER90-143-000, ER90-144-000, ER90-145-000 and EL90-9-000, on behalf of Massachusetts Municipal Wholesale Electric Company, concerning the effect of a proposed merger on competition and transmission access; May 25, 1990.

66. <u>Report to the Public Utilities Board of Manitoba concerning 1990 Manitoba Hydro Capital Projects Review: Generation and Transmission Requirements</u>. Whitfield Russell Associates was appointed to report to The Public Utilities Board on matters regarding the economic consequences to the domestic customers of the Manitoba Hydro capital program; August 28, 1990.

67. <u>In re: Northeast Utilities Service Company</u>, before the Federal Energy Regulatory Commission, Docket Nos. ER90-373-000, et al., on behalf of the Massachusetts Municipal Wholesale Electric Company, evaluating the Preferred Transmission Service Agreement between MMWEC and Northeast Utilities Service Company,

for the transmission of MMWEC's power purchase from the New York Power Authority; November 27, 1990.

68. In re: New Hampshire Electric Cooperative Rate Plan Proposal, before the New Hampshire Public Utilities Commission, Docket No. DR90-078, on behalf of the New Hampshire Electric Cooperative, concerning contract valuation; December 11, 1990.

69. Tampa Electric Company v. Zeigler Coal Company. This was an arbitration held in August 1991, concerning provisions of a coal contract in which Mr. Russell offered testimony for Zeigler to the effect that Tampa Electric was not suffering a hardship by measures commonly used in the electric utility industry.

70. In re: The Long Range Forecast of Ohio Power Company, before the Ohio Public Utilities Commission, Docket No. 90-660-EL-FOR (Phase II). Mr. Russell presented and defended testimony on behalf of Ormet Aluminum Corporation concerning Ormet's right to allowances to emit sulfur dioxide from the Kammer Power Plant of Ohio Power Company under the Clean Air Act Amendments of 1990 and the propriety of Ohio Power's Compliance Plan; July 17, 1991.

71. In re: Application of Tex-La Electric Cooperative to Increase Rates. Mr. Russell presented testimony in 1991, demonstrating that Tex-La was prudent in selling its entitlement in a nuclear plant and in settling its 1988 claims against Texas Utilities concerning Texas Utilities' fraud and imprudence in the construction of the Comanche Peak Nuclear Plant; June 1991.

72. In re: Southern California Edison Company, before the Federal Energy Regulatory Commission, Docket No. ER88-83, on behalf of the City of Vernon, California concerning expected effects of Edison's administration of its transmission network on competition, system operation and transmission access; June 1991.

73. In the Matter of the Application of the Public Service Company of New Mexico for Approval to Construct, Own, Operate and Maintain the Ojo Line Extension and for Related Approvals before the New Mexico Public Service Commission, Case No. 2382, on behalf of the United States Department of Energy, concerning transmission line construction programs of the Public Service Company of New Mexico; November 8, 1991.

74. In re: Wisconsin Public Power Inc. System et al., Advance Plan 6, before the Public Service Commission of the state of Wisconsin, Docket No. 05-EP-6, concerning Eastern Wisconsin Utility Joint Transmission System and Interface Study; December 31, 1991.

75. In re: MidAtlantic Energy v. Monongahela Power Company and the Potomac Edison Company, before the Public Service Commission of West Virginia, Case No. 89-783-E-C, on behalf of MidAtlantic Energy, concerning need for capacity

and the appropriate avoided cost; January 6, 1992, June 8, 1992 and February 13, 1992..

76. In re: Northeast Utilities Service Company, before the Federal Energy Regulatory Commission, Docket No. EL91-36-000, on behalf of the Massachusetts Municipal Wholesale Electric Company evaluating the tie-line adjustment charge borne by MMWEC that arose under a Transmission Service Agreement between New England Power Company and Northeast Utilities; May 1, 1992 and August 24, 1992.

77. In re: Application of Houston Lighting & Power Company for a Certificate of Convenience and Necessity for the DuPont Project, before the Public Utility Commission of Texas, Docket No. 11000, on behalf of Destec Energy, Inc; September 28, 1992, June 24, 1993 and June 29, 1993.

78. In re: Investigation on the Commission's Own Motion into Barriers to Contracts Between Electric Utilities and Nonutility Cogenerators and Certain Related Policy Issues, before the Public Service Commission of the state of Wisconsin, Docket No. 05-EI-112, on behalf of JOINT PARTIES: DESTEC Energy, Inc., EnerTran Technology Company, LS Power Corporation, The AES Corporation, LG&E Development Corporation, National Independent Energy Producers, and Citizens' Utility Board, concerning appropriate QF contract provision; November 23, 1992.

79. In re: Application of Cap Rock Electric Cooperative, Inc. for a Certificate of Convenience and Necessity, before the Public Utility Commission of Texas, Docket No. 11248, on behalf of Cap Rock Electric Cooperative, Inc., concerning its proposed transmission system improvements; December 30, 1992.

80. In re: Application of Texas Utilities for Authority to Change Rates, before the Public Utility Commission of Texas, Docket No. 11735, on behalf of Cap Rock Electric Cooperative, Inc., concerning standby rates, wholesale rate contracts and terms and conditions of the Power Sales Agreement, May 18, 1993.

81. In re: Determination of Houston Lighting & Power Company's Standard Avoided Cost Calculation for the Purchase of Firm Energy and Capacity from Qualifying Facilities Pursuant to P.U.C. Subst. R. 23.66(H)(3), before the Public Utility Commission of Texas, Docket No. 10832, on behalf of Destec Energy, Inc; August 11, 1993.

82. In re: Complaint of Phibro Refining, Inc. v. HL&P, Docket No. 11989, before the Public Utility Commission of Texas, on behalf of Phibro Energy, USA, Inc., concerning electric service contracts and terms and conditions of HL&P's industrial rate schedule; August 3, 1993.

83. In re: Application of Texas Utilities Electric Company for Authority to Implement Economic Development Service, General Service Competitive Pricing, Wholesale

Power Competitive Pricing, and Environmental Technology Service, Docket No. 13100, before the Public Utility Commission of Texas, on behalf of Rayburn Country Electric Cooperative, Inc., concerning TU Electric's so-called "competitive rates."; August 8, 1994

84. In re: Complaint of Kenneth D. Williams v. HL&P, Docket No. 12065, on behalf of Destec before the Public Utility Commission of Texas; January 10, 1995.

85. In re: Rebuttal testimony in a Complaint of Tex-La v. TUEC, Docket No. 12362, on behalf of Rayburn County Electric Coop. before the Public Utilities Commission of Texas; March 6, 1995.

86. In re: Application for Authorization and Approval of Merger Between Wisconsin Electric Power Company, Northern States Power Company (Minnesota), Northern States Power Company (Wisconsin), and Cenergy, Inc., in Docket No. EC-95-16-000, before the Federal Energy Regulatory Commission (on behalf of Certain Intervenors, including Madison Gas & Electric Company, Wisconsin Public Service Corporation, Minnesota Power & Light Company, Otter Tail Power Company and the Lincoln Electric System), in Docket Nos. 6630-UM-100 and 4220-UM-101, before the Wisconsin Public Service Commission and Docket No. 6-2500-10601-2 before the Minnesota Office of Administrative Hearings for the Minnesota Public Utilities Commission (both on behalf of Madison Gas & Electric, Wisconsin Industrial Energy Group, Wisconsin Federation of Cooperatives and the Citizen's Utility Board), concerning the effect upon transmission access of the merger of NSP and WEPCO into Primergy; May 10, 1996.

87. In re: Merger of The Washington Water Power Company and Sierra Pacific Power Company, Docket Nos. EC94-23-000 and ER95-808-000, before the Federal Energy Regulatory Commission, on behalf of Truckee Donner Public Utility District, concerning ancillary services and single system transmission rates; May 22, 1996.

88. In re: Alberta Electric Utilities 1996 Tariff Application before the Alberta Energy And Utilities Board, on behalf of the Industrial Power Consumers Association of Alberta concerning calculation of charges for ancillary services; June 3, 1996.

89. In re: Surrebuttal Testimony in Docket Nos. EC95-16-000, ER95-1357-000 and ER95-1358-000, on behalf of Madison Gas & Electric Company, Citizens Utility Board and Wisconsin Electric Cooperative Association; June 10, 1996.

90. In re: City Public Service Board of San Antonio Filing in Compliance with Subst. Rule 23.67, Docket No. 15613, before the Public Utility Commission of Texas, on behalf of Certain Power Marketers and Independent Power Producers, Destec Power Services and Enron Power Marketing, concerning Ancillary Services under the state-wide rate in Texas; September 5, 1996.

91. In re: City of Austin Filing in Compliance with Subst. Rule 23.67, Docket No. 15645, before the Public Utility Commission of Texas, on behalf of Certain Power Marketers and Independent Power Producers, Destec Power Services and Enron Power Marketing, concerning Ancillary Services under the state-wide rate in Texas; September 5, 1996.

92. In re: Central Power and Light and West Texas Utilities Filing in Compliance with Subst. Rule 23.67, Docket No. 15643, before the Public Utility Commission of Texas, on behalf of Certain Power Marketers and Independent Power Producers, Destec Power Services and Enron Power Marketing, concerning Ancillary Services under the state-wide rate in Texas; September 5, 1996.

93. In re: Texas Utilities Electric Company, Filing in Compliance with Subst. Rule 23.67, Docket No. 15638, before the Public Utility Commission of Texas, on behalf of Certain Power Marketers and Independent Power Producers, Destec Power Services and Enron Power Marketing, concerning Ancillary Services under the state-wide rate in Texas; September 18, 1996.

94. In re: Docket No. 15840, Regional Transmission Proceeding to Establish Postage Stamp Rate and Statewide Load Flow Pursuant to P.U.C. Subst. Rule. 23.67 on behalf of Certain Power Marketers and Independent Power Producers, Destec Power Services and Enron Power Marketing, concerning Ancillary Services under the state-wide rate in Texas; August 30, 1996.

95. In re: Application of Wisconsin Energy Corporation, Wisconsin Electric Power Company, Northern, States Power Company, and Northern States Power Company-Wisconsin for Approval of a Series of Transactions by Which Northern States Power Company-Wisconsin is merged into Wisconsin Electric Power Company, Northern States Power Company becomes a Subsidiary of Wisconsin Energy Corporation, and Wisconsin Energy Corporation is Renamed Primergy Corporation: Direct Testimony, Rebuttal Testimony and Surrebuttal Testimony on behalf of The Wisconsin Industrial Energy Group ("WIEG"), The Citizens' Utility Board ("CUB"), The Wisconsin Federation of Cooperatives ("WFC") and Madison Gas and Electric ("MG&E") in Docket Nos. 6630-UM-100 and 4220-UM-101 before the Public Service Commission of Wisconsin. The purpose of the direct testimony was to address Certain Intervenors' Transmission System Control Agreement and ISO Bylaws; October 8, 1996. The purpose of the rebuttal testimony was to address Applicants' Unilateral Settlement Offer which was submitted to FERC in their FERC merger proceeding; October 24, 1996. The purpose of the surrebuttal testimony was to address two sets of Rebuttal testimony of Jose Delgado and the Rebuttal Testimonies of Malcolm Bertsch of the Applicants and Don Carlson of Minnesota Power and Light; November 5, 1996.

95a. In re: In the Matter of Northern States Power Company's Petition for Approval to Merge with Wisconsin Energy Corporation; OAH Docket No. 6-2500-10601-2: Direct Testimony and Exhibits and Rebuttal Testimony and Exhibits on behalf of

Madison Gas and Electric ("MG&E"), The Wisconsin Federation of Cooperatives ("WFC"), and The Citizens' Utility Board ("CUB") in Docket No. E,G-002 and PA-95-500 before the Minnesota Office of Administrative Hearings for the Minnesota Public Utilities Commission. The purpose of the direct testimony is to remedy a Wisconsin Energy Corporation merger, in order to prevent anti-competitive effects with an Independent System Operation which actually operates the transmission system and which is truly independent of the proposed Primergy; October 21, 1996. The purpose of the rebuttal testimony is to address the direct testimony of Dr. Eilon Amit of Minnesota Department of Public Service and Dan Carlson of Minnesota Power and Light; November 8, 1996.

95b. In re: Joint Application of WPL Holdings, Inc. and Wisconsin Power & Light Company for all Requisite Approvals in Connection with a Series of Related Transactions by which Interstate Power Company Becomes a Subsidiary of WPL Holdings, Inc., IES Industries, Inc. is Merged into WPL Holdings, Inc. and is Renamed Interstate Power Corporation and for Certain Related Transactions and Matters: Direct Testimony and two Surrebuttal Testimonies on behalf of Badger Cooperative Group ("BCG"), The Citizens' Utility Board ("CUB"), Madison Gas and Electric ("MG&E"), The Wisconsin Federation of Cooperatives ("WFC"), Wisconsin Industrial Energy Group ("WIEG") and Municipal Wholesale Power Group ("MWPG") in Docket No. 6680-UM-100 before the Public Service Commission of Wisconsin. The purpose of the direct testimony was to discuss the characteristics of an appropriate ISO and present the ISO recommended by Certain Intervenors; May 7, 1997. The purpose of surrebuttal testimony #1 was to answer the rebuttal testimony of WP&L's witness Rodney Frame, Arnold Kehrli and Scott Wallace; May 30, 1997. The purpose of surrebuttal testimony #2 was to address the rebuttal testimony of WP&L's witness Arnold Kehrli; May 30, 1997.

96. In re: Houston Lighting & Power Company Filing in Compliance with Subst. Rule 23.67, Docket No. 15639, before the Public Utility Commission of Texas, on behalf of Certain Power Marketers and Independent Power Producers, Destec Power Services and Enron Power Marketing, concerning Ancillary Services under the state-wide rate in Texas; September 30, 1996.

97. In re: IES Utilities, Inc., Interstate Power Company, Wisconsin Power & Light Company, South Beloit Water, Gas & Electric Company, Heartland Energy Services, and Industrial Energy Applications, Inc., Docket Nos. EC96-13-000, ER96-1236-000, and ER96-2560-000, before the Federal Energy Regulatory Commission, on behalf of Wisconsin Intervenors ("WI"). Mr. Russell simultaneously filed 2 sets of testimony; the first, sponsored by the intervenors listed above as well as by Wisconsin Public Service Corporation ("Pub Service"), and Dairyland Power Cooperative. ("Dairyland") analyzed engineering and operating problems created by the merger of WP&L, IPW and IES. The second set of testimony discusses how the IEC Independent System Operator ("ISO") fails in general to meet the rigorous and comprehensive ISO standards promulgated by the Wisconsin Public Service Commission (WPSC). Both sets of testimony

(Engineering and ISO) were filed before the Federal Energy Commission; March 27, 1997.

98. In re: Joint Application of WPL Holdings, Inc. and Wisconsin Power & Light Company for all Requisite Approvals in Connection with a Series of Related Transactions by which Interstate Power Company Becomes a Subsidiary of WPL Holdings, Inc., IES Industries, Inc. is Merged into WPL Holdings, Inc. and is Renamed Interstate Power Corporation and for Certain Related Transactions and Matters, in Docket No. 6680-UM-100, before the Public Service Commission of Wisconsin; May 7, 1997.

99. In re: City of College Station, FERC Docket No. TX 96-2-000, concerning transmission rates; November 7, 1997.

100. In re: Application for Approval of Restructuring Plan Under Section 2806 of the Public Utility Code, in Docket No. R-00973981 on behalf of Mid-Atlantic Power Supply Association, before the Pennsylvania Public Utility Commission; November 7, 1997.

101. In re: Application for Approval of Restructuring Plan Under Section 2806 of the Public Utility Code, in Docket No. R-00974104 on behalf of Mid-Atlantic Power Supply Association, before the Pennsylvania Public Utility Commission; November 7, 1997.

102. In re: New England Power Company, FERC Docket No. OA96-74-000, concerning proposed formula rates for Tariffs No. 9 and 4, on behalf of the Massachusetts Municipals; December 12, 1997.

103. In re: Sierra Pacific Power Company before the Federal Energy Regulatory Commission in Docket Nos. ER97-3593-000, ER97-3779-000, ER97-4462-000 on behalf of Truckee Donner Public Utility District, addressing lack of comparable access to transmission systems; February 23, 1998.

104. In re: Application for Approval of Restructuring Plan Under Section 2806 of the Public Utility Code, on behalf of Newmont Gold Company and Barrick Goldstrike Mines, in Docket Nos. 97-11018 and 97-11028, before the Public Service Commission of Nevada; February 1, 1998.

105. In re: Southern California Edison Company before the Federal Energy Regulatory Commission in Docket No. ER97-2355-000 on behalf of Department of Water Resources of the State of California, regarding lower pricing for off-peak transmission services; April 1998.

106. In re: Response to Procedural Order Number Three Load Pockets, on behalf of Newmont Gold Company and Barrick Goldstrike Mines, Docket Number 97-8001, before the Public Utilities Commission of Nevada; May 15, 1998.

107. In re: Supplemental Testimony in an Application for Approval of Restructuring Plan Under Section 2806 of the Public Utility Code, on behalf of Newmont Gold Company and Barrick Goldstrike Mines, Docket Numbers 97-11018 and 97-11028, before the Public Utilities Commission of Nevada, May 22, 1998.

108. In re: Southern California Edison Company, on behalf of The Department of Water Resources of The State of California, Docket No. ER97-2355, before FERC in reference to Transmission Revenue Balancing Account Adjustment ("TRBAA"); November 16, 1998.

109. In re: Ormet Primary Aluminum Corporation, on behalf of Ormet Primary Aluminum Corporation, Arbitration Number 55-199-0051-94, before the American Arbitration Association, concerning the relationship between AEP and other power systems within NERC and ECAR; July 14 1998.

110. In re: Rebuttal Testimony in response to Mr., Walter R. Kelley and Mr. Thomas Kennedy, on behalf of Ormet Primary Aluminum Corporation, Arbitration Number 55-199-0051-94, before the American Arbitration Association; September 2, 1998.

111. In re: Application No. RE95081 – TransAlta Utilities Corp., on behalf of Albchem Industries Ltd., CXY Chemicals and Dow Chemicals Canada Ltd., before the Alberta Energy & Utilities Board addressing ACD’s interest in providing interruptible service; October 1998.

112. In re: Tri-State Generation and Transmission Assoc., Inc., in Arbitration No. 77 Y 181 0023097 before the American Arbitration Association; September 14, 1998.

113. In re: Joint Application for Approval of Merger, Docket No. 98-7023 on behalf of The Staff of the Public Utilities Commission, before the Public Utilities Commission of Nevada; November 9, 1998.

114. In re: Independent System Administrator, Docket No. 97-8001 on behalf of The Staff of the Public Utilities Commission, before the Public Utilities Commission of Nevada; December 11, 1998.

115. In re: Petition for Order Concerning Delineation of Transmission and Local Distribution Facilities, Docket No. 98-0894 on behalf of The City of Chicago, before the Illinois Commission in reference to re-functionalization; April 2, 1999.

116. In re: Consolidated Edison Company, Docket No. EL99-58-000 on behalf of The Village of Freeport, New York, before FERC in reference to remedies for the breach of contract to provide firm service on a non-discriminatory basis; July 22, 1999, August 3, 1999, August 18, 1999 and September 9, 1999.

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117. In re: Wisconsin Public Power, Inc. Docket No. 05-EI-119 on behalf of Wisconsin Transmission Customer Group (WTCG"), before the Public Service Commission of Wisconsin to address the concerns of municipally-owned utilities within Wisconsin; March 6, 2000.

118. In re: Joint Application of Utilicorp United Inc. & St. Joseph Light & Power Co., Docket No. EM-2000-292 on behalf of Springfield (MO) City Utilities before the PSC of the State of Missouri to address why the merger between the two is detrimental to the public interest; May 1, 2000.

119. In re: Utilicorp United Inc, and Empire District Electric Co. Docket No. EM-2000-369 on behalf of Springfield (MO) City Utilities before the Public Service Commission of the State of Missouri to explain why the merger between the two is detrimental to the public interest; June 19, 2000.

120. In re: Arrowhead - Westin Transmission Line Project, Docket No. 05-CE-113 on behalf of the Wisconsin Public Service Corporation ("WPSC"), before the Public Service Commission of the State of Wisconsin to provide support for the transmission project as proposed by WPSC and Minnesota Power; November 22, 2000.

121. In re: Kansas Municipal Energy Agency ("KMEA"), Docket No. ER00-2644-000 on behalf of the Kansas Municipal Energy Agency ("Kansas Municipal"), before the Federal Energy Regulatory Commission ("FERC") to review, assess and comment on the actions taken by the Southwest Power Pool in connection with two transmission service requests made by the Kansas Municipal Energy Agency aggregating 39 MW of contract demand; December 8, 2000.

122. In re: Arrowhead - Weston 345 kV Transmission Line, Rebuttal testimony in Docket No. 05-CE-113 on behalf of the Wisconsin Public Service Corporation ("WPSC"), before the Public Service Commission of the State of Wisconsin to address matters set forth in the direct testimony of Dr. Richard A. Rosen on behalf of Save Our Unique Lands ("SOUL"), Mr. David Schoengold on behalf of Wisconsin's Environmental Decade, and Mr. George R. Edgar on behalf of the Citizens' Utility Board ("CUB"); December 18, 2000.

123. In re: Ethyl Corporation verses Gulf States Utilities Company, Civil Docket No. M, live direct testimony in a dispute over direct assignment of substation facilities; April 2001.

124. In re: Joint Application of Entergy Louisiana, Inc. and Entergy Gulf States, Inc., Docket No. U-25533 on behalf of Occidental Chemical Corporation ("OxyChem"), before the Louisiana Public Service Commission for authorization to participate in contracts for the purchase of capacity and electric power for the Summer of 2001; May 3, 2001.

125. In re: Petitioners' Joint Proposal for Merger & Rate Plan, testimony in Case No. 01-M-0075 on behalf of Alliance for Municipal Power before the New York State Public Service Commission. The purpose of this testimony is explain (1) the inappropriateness of Rule 52 in the post merger competitive energy markets; (2) to have stranded transmission cost and distribution costs expunged; and (3) to show how merged Companies exacerbates the incentive to abuse Rule 52 against newly formed municipal utilities; November 5, 2001.

126. In re: Northeast Utilities Service Company Transmission Line Project, direct testimony in Docket No, 217 before the Connecticut Siting Council of the State of Connecticut on behalf of the Attorney General, State of Connecticut for the purpose of (1) Whether there is a need for the 345 f transmission line from Plum-tree to Norwalk; (2) whether the proposed transmission system design is the best option based on current transmission design and (3) whether any approval of the project by the Siting Council should be conditioned upon CL&P and NU's agreement; March 12, 2002.

127. In re: Alliance Companies, et al., Affidavit in Docket Nos. RM01-12-000, RT01-87-000 and RT01-88-000, before the Federal Energy Regulatory Commission on behalf of the Ormet Primary Aluminum Corporation, for the purpose of providing relevant engineering fundamentals related to the proper design of methodology for quantifying transmission losses and for allocating such losses to the customers of regional transmission organizations; March 12, 2002.

128. In re Cannon Power Corporation:, Affidavit in Docket No. ER02-2189-000, before the Federal Energy Regulatory Commission on behalf of Whitewater Hill Wind Partners, LLC developing a 66 MW wind power project to be interconnected to Southern California Edison Company; July 29, 2002.

129. In re Cannon Power Corporation:, Affidavit in Docket No. ER02-1764, before the Federal Energy Regulatory Commission on behalf of Cabazon Wind Partners, LLC developing a 66 MW wind power project to be interconnected to Southern California Edison Company; August 2, 2002.

130. In re: Response to Pacificorp's Motion: Affidavit in Response to Pacificorp's Daubert Motion Regarding Richard Slaughter and Supplemental Expert Report on behalf of Snake River Valley Electric Association; September 10, 2002.

131. In re: Pacific Gas & Electric Company : Direct Testimony in Docket No. ER01-2998, before the Federal Energy Regulatory Commission on behalf of Northern California Power Agency to explain what level of firmness is required of transmission service under the Stanislaus Commitments; December 20, 2002.

132. In re: American Electric Power Corp.: Affidavit in Docket No. ER03-242, before the Federal Energy Regulatory Commission on behalf of Ormet Primary Aluminum Corp. to respond to AEP's proposed electric transmission rates to be included in the OATT of the PJM Interconnection; December 24, 2002.

133. In re: Application of the CT Light & Power Company: Supplemental Direct Testimony in Docket No. 217, before the State of CT Siting Council on behalf of The Attorney General, State of CT as a follow-up to the direct testimony filed on March 12, 2002 and to address various studies and reports that have been filed since that original testimony; January 14, 2003.

134. In re: Pacific Gas & Electric: Rebuttal Testimony before the Federal Energy Regulatory Commission in Docket No. ER01-2998 on behalf of Northern California Power Agency ("NCPA") to respond to testimony from witnesses Judi K. Mosley, Kevin J. Dasso, Dr. Roy Shanker and Linda Patterson; April 1, 2003.

135. In re: Order Instituting Investigation into implementation of Assembly Bill 970 regarding the identification of electric transmission and distribution constraints, actions to resolve those constraints, and related matters affecting the reliability of electric supply: Direct testimony before the Public Utilities Commission of California on behalf of Oak Creek Energy Systems. The purpose of the testimony is to provide comments on and recommendations with respect to the Tehachapi Transmission Conceptual Facility Study ("Tehachapi CFS" or "TCFS"), performed by Southern California Edison ("SCE" or "Edison"); April 22, 2003.

136. In re: Order Instituting Investigation into implementation of Assembly Bill 970 regarding the identification of electric transmission and distribution constraints, actions to resolve those constraints, and related matters affecting the reliability of electric supply: Rebuttal testimony before the Public Utilities Commission of California on behalf of Oak Creek Energy Systems. The purpose of the testimony is to rebut the testimony of Mr. Jorge Chacon and Mr. Melvin Stark on behalf of Southern California Edison Company, taking into account the testimony of Mr. Robert Sparks filed on behalf of the California Independent System Operator ("CA ISO" or "ISO"); May 13, 2003.

137. In re: California Independent System Operator Corporation: Direct testimony before the Federal Energy Regulatory Commission in Docket No. ER00-2019 on behalf of State Water Contractors and the Metropolitan Water District of Southern California. The purpose of the testimony is to provide a critical analysis of ISO's proposed Transmission Access Charge; June 2, 2003.

138. In re: Ameren Services Company, et al.: Affidavit in Docket No. EL03-212-000, before the Federal Energy Regulatory Commission on behalf of Ormet Primary Aluminum Corp. to respond to AEP's Submission in Response to the Commission's Section 206 Investigation; September 2, 2003.

139. In re: Pacific Gas and Electric Company: Direct Testimony in Phase I before the Federal Energy Regulatory Commission in Docket Nos. ER00-565-000, ER00-565-003, and ER00-565-007 on behalf of the Northern California Power Agency. The purpose of the testimony is to explain the nature of the costs for which Pacific Gas

and Electric Company seeks recovery through its Scheduling Coordinator Service Tariff; September 15, 2003.

140. In re: California Independent System Operator Corporation: Surrebuttal Testimony before the Federal Energy Regulatory Commission in Docket Nos. ER00-2019-006, ER01-819-002, and ER03-608-000 on behalf of State Water Contractors and the Metropolitan Water District of Southern California. The purpose of the testimony is to respond to the Prepared Rebuttal Testimony of Mr. Johannes P. Pfeifenberger on behalf of the ISO; October 20, 2003.

141. In re: Midwest Independent Transmission System Operator, Inc. and Public Utilities With Grandfathered Agreements in the Midwest ISO Region: Prepared Testimony before the Federal Energy Regulatory Commission in Docket Nos. ER04-691-000 and EL04-104-000 on behalf of Marshfield Electric & Water District. The purpose of the testimony is to review Marshfield Electric & Water District's transmission arrangements in order to respond to the Commission's May 26, 2004 Order in this proceeding; June 25, 2004.

142. In re: Pacific Gas and Electric Company: Direct Testimony in Phase II before the Federal Energy Regulatory Commission in Docket Nos. ER00-565-000 and ER00-565-003 on behalf of the Northern California Power Agency ("NCPA"). The purpose of the testimony is to discuss PG&E's propriety in passing through ISO Charge Type costs as Scheduling Coordinator Service charges to NCPA under the terms of the NCPA-PG&E Interconnection Agreement; September 13, 2004.

143. In re: Southern California Edison Company: Prepared Direct Testimony before the Federal Energy Regulatory Commission in Docket No. ER02-2189-003 on behalf of Whitewater Wind Hill Partners. The purpose of the testimony is to provide support for Whitewater's request that the Commission revise the Interconnection Facilities Agreement ("IFA") between Whitewater and Southern California Edison Company ("SCE or Edison"); September 14, 2004.

144. In re: Cabazon Wind Partners, LLC Complainant vs. Southern California Edison Company Respondent: Affidavit in Docket No. EL04-137 before the Federal Energy Regulatory Commission on behalf of Cabazon Wind Partners, LLC ("Cabazon"). This Affidavit provides support for Cabazon's request that Southern California Edison Company ("SCE") grant Cabazon reimbursement, in the form of a transmission credit or otherwise, for the cost of certain upgrades Cabazon has borne to interconnect its generation to SCE; September 27, 2004.

145. In re: Southern California Edison Company: Cross Answering Testimony before the Federal Energy Regulatory Commission in Docket No. ER02-2189-003 on behalf of Whitewater Hill Wind Partners. The purpose of the testimony is to respond to testimony filed on October 28, 2004, in this proceeding by Commission Staff witnesses, Ms. Tania Martinez Navedo and Mr. Edward W.

Mills. As discussed in my prior testimony, the issue in this case involve the designation of disputed upgrades contained in the IFA between Whitewater and Southern California Edison Company; November 22, 2004.

146. In re: Pacific Gas and Electric Company: Direct and Answering Testimony before the Federal Energy Regulatory Commission in Docket No. ER01-1639-006 on behalf of Northern California Power Agency. The purpose of this testimony is to explain 1) PG&E's failure to justify the pass-through of Reliability Service charges to Western and PG&E's additional failure to "unbundle the rates in its ETCs and provide a full cost of service analysis supporting the unbundled rates," 2) PG&E's attempt to pass-through Scheduling Coordinator Service Charges to Western, and 3) The inappropriateness of PG&E's imposition of interest charges; November 23, 2004.

147. In re: Petition for a Declaratory Order or Advisory Opinion as to the Applicability of the Commission's Decision in Docket No. 03-10003, Plant Project in Orange County, California: Affidavit in Docket No. 04-10023, before the Public Utilities Commission of Nevada on behalf of Ridgewood Renewable Power, LLC ("Ridgewood") with respect to a landfill methane gas powered electric generating project located at the Olinda/ Alpha landfill in Orange County, California; December 30, 2004.

148. In re: Southern California Edison Company and Cabazon Wind Partners, LLC: Prepared Direct Testimony before the Federal Energy Regulatory Commission in Docket No. EL04-137, on behalf of Cabazon Wind Partners, LLC. The purpose of this testimony is to provide support for Cabazon's request that Southern California Edison ("SCE") grant Cabazon reimbursement, in the form of transmission credit or otherwise, for the cost of certain upgrades Cabazon has borne to interconnect generation to SCE; February 4, 2005.

149. In re: Pacific Gas and Electric Company: Phase II Answering Testimony to PG&E's Supplemental Testimony; Cross Answering Testimony; and Errata of Whitfield A. Russell before the Federal Energy Regulatory Commission in Docket No. ER00-565-000, et al and ER04-1233-000, on behalf of Northern California Power Agency. The purpose of this testimony is to respond to Mr. Bray's contention that the SCS Tariff is a formula rate, to respond to aspects of the Prepared Direct and Answering Testimony of Ms. Linda M. Patterson on behalf of the Federal Energy Regulatory Commission Staff and to provide updates to my previously filed testimony, March 8, 2005.

150. In re: Southern California Edison Company: Affidavit before the Federal Energy Regulatory Commission in Docket No. EL05-80-000, on behalf of the California Wind Energy Association ("CalWEA"). The purpose of this affidavit is to explain how and why the proposed Antelope-Tehachapi 230 kV line will be integrated into the regional transmission grid and thereby constitute a network upgrade facility; April 14, 2005.

151. In re: American Electric Power Service Corporation: Affidavit before the Federal Energy Regulatory Commission in Docket No. ER05-751-000, on behalf of Ormet Primary Aluminum Corporation. The purpose of this affidavit is to respond to American Electric Power Corporation's (AEP's) request (a) to increase its annual Network Integration Transmission Service (NTS) revenue requirements to $486 million per year and (b) to increase the NTS rates; April 29, 2005.

152. In re: Southern California Edison Company and Cabazon Wind Partners, LLC: Prepared Rebuttal Testimony before the Federal Energy Regulatory Commission in Docket No. EL04-137, on behalf of Cabazon Wind Partners, LLC. The purpose of this testimony is to respond to direct testimony filed on March 14, 2005 and cross answering testimony filed on May 3, 2005 by Mr. Daniel J. Allstun, the witness of Southern California Edison and to respond to testimony filed on April 14, 2005 by Commission Staff witness, Ms. Emily White; May 20, 2005.

153. In re: In the Matter of the Arbitrations between PG&E Energy Trading-Power, LP Claimant, Counter-Respondent and Southaven Power, LLC, and Caledonia Generating, LLC, Respondents, Counter-Claimants: Expert Report and litigation before the American Arbitration Association in AAA Nos. 16-198-00206-03 & 16-198-00207-03, on behalf of Williams & Connolly LLP (counsel of Southaven Power, LLC) and Bingham McCutchen LLP (counsel for Caledonia Generating, LLC). The purpose of this expert report was to provide my opinion on certain elements of the matters in dispute between PG&E Energy Trading-Power, L.P., on the one hand, and each of Southaven and Caledonia, on the other hand. These disputes have arisen in connection with two similar tolling agreements, each titled "Dependable Capacity and Conversion Services Agreement;" September 8, 2005.

154. In re: Midwest Independent Transmission System Operator, Inc: Pre-Filed Answering Testimony before the Federal Energy Regulatory Commission in Docket No. ER05-6-001, et al, on behalf of Ormet Primary Aluminum Corporation. The purpose of this testimony is to analyze the proposed SECA rate design as it relates to Ormet; October 24, 2005.

155. In re: Berkshire Power Company, LLC: Affidavit before the Federal Energy Regulatory Commission in Docket No. ER05-1179-001, on behalf of Massachusetts Municipal Wholesale Electric Company, Chicopee Municipal Lighting Plant, and South Hadley Electric Light Department. The purpose of this affidavit is to review the engineering analysis performed by ISO New England in support of its determination of the system reliability for the Springfield, Massachusetts area in Western Massachusetts and, more specifically, the ISO's analysis of the reliability need for two units in that area: (1) the 245 MW Berkshire facility operated by Berkshire Power Company; and (2) the 107 MW West Springfield Unit 3 operated by Consolidated Edison Energy Massachusetts, Inc.; November 7, 2005.

156. In re: Consolidated Edison Energy Massachusetts, Inc.: Affidavit before the Federal Energy Regulatory Commission in Docket No. ER05-903-002, on behalf of Massachusetts Municipal Wholesale Electric Company, Chicopee Municipal Lighting Plant, and South Hadley Electric Light Department. The purpose of this affidavit is to review the engineering analysis performed by ISO New England in support of its determination of the system reliability for the Springfield, Massachusetts area in Western Massachusetts and, more specifically, the ISO's analysis of the reliability need for two units in that area: (1) the 245 MW Berkshire facility operated by Berkshire Power Company; and (2) the 107 MW West Springfield Unit 3 operated by Consolidated Edison Energy Massachusetts, Inc.; November 10, 2005.

157. In re: Pittsfield Generating Company, LP: Affidavit before the Federal Energy Regulatory Commission in Docket No. ER06-262-000, on behalf of Massachusetts Municipal Wholesale Electric Company, Chicopee Municipal Lighting Plant, and South Hadley Electric Light Department. The purpose of this affidavit is to review the engineering analysis performed by ISO New England in support of its evaluation of the system reliability for the Pittsfield, Massachusetts area of Western Massachusetts and, more specifically, the ISO's analysis of the reliability need for the 160 MW facility operated by Pittsfield Generating Company, L.P.; December 21, 2005.

158. In re: Mystic Development LLC: Affidavit before the Federal Energy Regulatory Commission in Docket No. ER06-427-000, on behalf of Massachusetts Municipal Wholesale Electric Company, Wellesley Municipal Light Plant, Reading Municipal Light Department and Concord Municipal Light Plant. The purpose of this affidavit is to (a) respond to portions of the testimony offered by Mystic witnesses Messrs. Theodore Horton, Robert B. Stoddard, and Alan C. Heintz; and (b) review the engineering analysis of the December 7, 2004, "Need for Mystic Units 7, 8 and 9 for System Reliability," performed by ISO New England ("ISO") and included by Mystic in its filing as support for the assertion that Mystic Units 8 and 9 are needed to ensure system reliability in the Northeast Massachusetts/Boston Area load pocket; January 19, 2006.

159. In re: In the Matter of the Application of Ohio Power Company for Approval of a Special Contract Arrangement with Ormet Primary Aluminum Corporation, In the Matter of the Joint Petition of Ohio Power Company and South Central Power Company for Reallocation of Territory, In the Matter of: Ormet Primary Aluminum Corporation and Ormet Primary Mill Products Corporation v.South Central Power Company and Ohio Power Company: Pre-Filed Testimony before the Public Utilities Commission of Ohio in Docket Nos. 96-999-EL-AEC, 96-1000-EL-PEB and 05-1057-EL-CSS, on behalf of Ormet Primary Aluminum Corporation. The purpose of this testimony is to analyze: (a) the effect upon the ratepayers of South Central and Buckeye of requiring South Central to serve Ormet and (b) the effect upon the ratepayers and stockholders of Ohio Power

Company ("OPCO") of requiring OPCO to serve Ormet's full requirements under OPCo's retail GS-4 rate schedule; September 8, 2006.

160. In re: Mystic Development, LLC: Direct Testimony before the Federal Energy Regulatory Commission in Docket No. ER06-427-000, on behalf of Massachusetts Municipal Wholesale Electric Company, Reading Municipal Light Department Wellesley Municipal Light Plant and Concord Municipal Light Plant. The purpose of this testimony is to assess whether a cost-of-service ("COS"), Reliability Must-Run ("RMR") Agreement is needed in order to keep Mystic Development LLC's ("Mystic's") Units 8 and 9 available to provide reliability service and if, contrary to my testimony, the Commission finds that a COS RMR agreement is needed to keep Mystic Units 8 and 9 available to provide reliability service, the Commission would be required to determine a just and reasonable COS rate to be imposed on customers under the RMR agreement. I testify regarding adjustments that need to be made to Mystic's proposed COS rates in order to render them just and reasonable; November 9, 2006.

161. In re: Hydroelectric Production Rates and Rate Modification Plan-2007 and 2008 Rate Years: Direct Testimony and Supporting Exhibits before the New York Power Authority, on behalf of the New York Association of Public Power. The purpose of this testimony is to address the understatement of capacity at the Niagara and St. Lawrence Projects of the New York Power Authority ("NYPA") and how that understatement of capacity improperly reduces the amount of capacity made available to preference customers of the Niagara Project and improperly increases the rates applicable to capacity sold to those customers; April 9, 2007.

162. In re: ISO New England Inc: Affidavit before the Federal Energy Regulatory Commission in Docket No. ER08-190-000, on behalf of Massachusetts Municipal Wholesale Electric Company ("MMWEC"). The purpose of this testimony is to review the engineering analysis performed by ISO New England Inc. in support of its determination that MMWEC's Phase II Stony Brook Unit is not qualified to participate in the first Forward Capacity Market auction, scheduled to be held in February 2008; November 21, 2007.

163. In re: Columbus Southern Power Company and Ohio Power Company: Affidavit before the Public Utilities Commission of Ohio in Case Nos. 07-1132-EL-UNC, 07-1191-EL-UNC, 07-1278-EL-UNC, and 07-1156-EL-UNC, on behalf of Ormet Primary Aluminum Company. The purpose of this affidavit is in the matter of the Application of Columbus Southern Power Company and Ohio Power Company for approval of an additional generation service rate increase pursuant to their post-market development period rate stabilization plans and to update each company's transmission cost recovery rider; February 28, 2008.

164. In re: Niagara Mohawk Power Corporation: Affidavit before the Federal Energy Regulatory Commission in Docket No. ER08-552-000, on behalf of the New York Association of Public Power and several of its members which include

Green Island Power Authority, Jamestown Board of Public Utilities, City of Salamanca Board of Public Utilities, City of Sherrill Power & Light and Oneida-Madison Electric Cooperative, Inc. The purpose of this affidavit is review the filing by NMPC for Amendments to its Wholesale Transmission Service Charge for Point-to-Point Transmission service and Network Integration Transmission Service; March 17, 2008.

165. In re: Braintree Electric Light Department, Hingham Municipal Lighting Plant, Hull Municipal Lighting Plant, Mansfield Municipal Electric Department, Middleborough Gas and Electric Department and Taunton Municipal Light Plant v. ISO New England Inc.: Direct Testimony and Exhibits before the Federal Energy Regulatory Commission in Docket No. EL08-48-000, on behalf of the individually municipally-owned power systems serving the Massachusetts communities of Hull, Mansfield, Middleborough, Taunton, Braintree and Hingham. The purpose of this testimony is to provide technical support for the MPS complaint; March 28, 2008.

166. In re: Entergy Nuclear Operations Inc. and Entergy Nuclear Palisades, Inc. (Palisades Nuclear Plant), Entergy Nuclear Operations Inc. and Entergy Nuclear Fitzpatrick, Inc. (James A. Fitzpatrick Nuclear Power Plant), Entergy Nuclear Operations Inc. and Entergy Nuclear Generation Company (Pilgrim Nuclear Power Station), Entergy Nuclear Operations Inc. and Entergy Nuclear Vermont Yankee, Inc. (Vermont Yankee Nuclear Power Station), Entergy Nuclear Operations Inc.; Entergy Nuclear Indian Point 2, LLC; and Energy Nuclear Indian Point 3, LLC (Indian Point Nuclear Generating Unites Nos. 1, 2, and 3), and Entergy Nuclear Operations Inc. and Entergy Nuclear Palisades, LLC. (Big Rock Point): Affidavit before the Nuclear Regulatory Commission in Docket Nos. 50-255-LT and 72-7-LT, 50-333-LT and 72-12-LT, 50-293-LT, 50-271-LT, 50-003-LT, 50-247-LT and 50-286-LT and 50-155-LT and 72-43-LT, on behalf of the Locals 369 and 590, Utility Workers Union of America, AFL-CIO. The purpose of this affidavit is to provide support for the April 15, 2008 Reply of Locals 369 and 590, Utility Workers Union of America, AFL-CIO to Answer of Energy Nuclear Operations, Inc. Opposing Petitions for Leave to Intervene, Request for Hearing, and Related Requests for Relief; April 15, 2008.

Exhibit No. 2

NPCC, Inc.

NORTHEAST POWER COORDINATING COUNCIL, INC.
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NPCC
Regional Reliability Reference Directory # 7
Special Protection Systems

Task Force on System Protection Revision Review Record
December 27, 2007

Adopted by the Members of the Northeast Power Coordinating Council Inc., this December 27, 2007, based on recommendation by the Reliability Coordinating Committee, in accordance with Section VIII of the NPCC Amended and Restated Bylaws dated July 24, 2007 and as amended to date.

Table of Contents

Introduction

1.1 Title Special Protection Systems

1.2 Directory Number 7

1.3 Objective

Provide the basic criteria for **Special Protection Systems** such that the **Bulk Power System** in NPCC Inc. member **Areas** is operated reliably.

1.4 Effective Date Immediately upon Approval by the NPCC Full Members

1.5 Background

This directory establishes the basic **protection** criteria for **Special Protection Systems**. It is not intended to be a design specification. It is recognized that responsible entities in certain **Areas** may choose to apply more rigid criteria because of local considerations.

Guidance for consideration in the implementation of these criteria is provided in Appendix A, and the procedure for reviewing new and revised **Special Protection Systems** is provided in Appendix B.

1.6 Applicability

1.6.1 Functional Entities

Transmission Owner Generator
Owner Distribution Provider

1.6.2 Facilities

1.6.2.1 New Facilities

The standard requirements and criteria stipulated in this Directory apply to all new Type I and Type II **Special Protection Systems** (SPSs) as defined below. In the application of Type II SPSs, their security is the prime concern (see Section 3.3.1 of this document). As such, Sections 3.3.1.1, 3.3.2.3, 3.3.3.2, 3.3.6 and 3.3.8.1 in this document do not apply to Type II.

1.6.2.2 Existing Facilities

It is the responsibility of individual Transmission Owners (TO), Generator Owners (GO) and Distribution Providers (DP) to assess their existing **Special Protection Systems** and to make modifications which are required to meet the intent of these standards as follows:

a. Planned Renewal or Upgrade to Existing Facilities It is recognized that there may be **SPSs,** which existed prior to each TO's, GO's and DP's adoption of the *Special Protection System Criteria* that do not meet these criteria. If any **Special Protection Systems** or sub-systems of these facilities are replaced as part of a planned renewal or upgrade to the facility and do not meet all of these criteria, then an assessment shall be conducted for those criteria that are not met. The result of this assessment shall be reported on TFSP Form #1-5.

b. SPS Re-classified to Type I or Type II

These requirements apply to all existing SPSs which are reclassified as Type I or Type II due to system changes. A mitigation plan shall be required to bring such a SPS into compliance with these criteria.

c. In-kind Replacement of SPS Equipment

If SPS equipment is replaced "in-kind" as a result of an un-planned event, then it is not required to upgrade the associated protection system to comply with these criteria.

1.6.3 Classification of **Special Protection Systems**

Special Protection Systems are sub-divided into three types. Reference can be made to the NPCC *Basic Criteria for Design and Operation of Interconnected Power Systems* (Document A-2) where design criteria contingencies are described in Section 5.0; operating criteria contingencies, in Section 6.0; and extreme contingencies, in Section 7.0 of Document A-2.

Type I — A **Special Protection System** which recognizes or anticipates abnormal system conditions resulting from design and operating criteria **contingencies**, and whose misoperation or failure to operate would have a **significant adverse impact** outside of the local area. The corrective action taken by the **Special Protection System** along with the actions taken by other **protection systems** are intended to return power system parameters to a stable and recoverable state.

Type II — A **Special Protection System** which recognizes or anticipates abnormal system conditions resulting from extreme **contingencies** or other extreme causes, and whose misoperation or failure to operate would have a **significant adverse impact** outside of the local area.

Type III — **Special Protection System** whose misoperation or failure to operate results in no **significant adverse impact** outside the local area. The practices contained in this document for a Type I SPS should be considered but are not required for a Type III SPS. It should be recognized that a Type III SPS may, due to system changes, become Type I or Type II.

2.0 Terms Defined in this Directory

The following terms are defined in this Directory. Their definitions are provided in Attachment 1.

Bulk Power System
Contingency
Fault
Operating Procedures
Protection
Special Protection System (SPS)
Teleprotection

3.0 Requirements

3.1 The NERC ERO Reliability Standards containing Requirements that are associated with this Directory include, but may not be limited to:

3.1.1 PRC-012-0 — Special Protection System Review Procedure

3.1.2 PRC-013-0 Special Protection System Database

3.1.3 PRC-014-0 — Special Protection System Assessment

3.1.4 PRC-015-0 — Special Protection System Data and Documentation

3.1.5 PRC-016-0 — Special Protection System Misoperations

3.1.6 PRC-017-0 - Special Protection System Maintenance and Testing

3.2 NPCC Regional Reliability Standard Requirements

None at this time. To be developed.

3.3 NPCC "Full Member", More Stringent Criteria

3.3.1 General Criteria

A **Special Protection System** shall be designed to recognize or anticipate the specific power system conditions associated with the intended function.

Due consideration shall be given to dependability and security. The relative effect on the **bulk power system** of a failure of an SPS to operate when desired versus an unintended operation shall be weighed carefully in selecting design parameters as follows:

3.3.1.1 To enhance dependability, a **Special Protection System** shall be designed with sufficient redundancy such that the **Special Protection System** is capable of performing its intended function while itself experiencing a single failure.

3.3.1.2 Multiple protection groups that are used to obtain redundancy within a **Special Protection System** shall not share the same component.

3.3.1.3 A **Special Protection System** shall be designed to avoid false operation while itself experiencing a credible failure.

3.3.1.4 The thermal capability of all **Special Protection System** components shall be adequate to withstand the maximum short time and continuous loading conditions to which the associated power system elements may be subjected.

3.3.1.5 Communication link availability, critical control switch and test switch positions, and trip circuit integrity, shall be monitored to allow prompt attention by appropriate operating authorities.

3.3.1.6 When remote access to **Special Protection Systems** is possible, the design shall include security measures to minimize the probability of unauthorized access to the **Special Protection System**.

3.3.1.7 An SPS shall be designed to take corrective action within times determined by studies with due regard to security, dependability and selectivity.

3.3.1.8 Status of SPS arming shall be monitored to allow prompt attention by appropriate operating authorities.

3.3.1.9 An SPS shall be equipped with means to enable its arming and to independently verify the arming.

3.3.2 Current Transformer Criteria

Current transformers (CTs) associated with **Special Protection Systems** shall have adequate steady-state and transient characteristics for their intended function.

3.3.2.1 The output of each current transformer secondary winding shall be designed to remain within acceptable limits for the connected burdens under all anticipated currents, including **fault** currents, to ensure correct operation of the **Special Protection System**.

3.3.2.2 The thermal and mechanical capabilities of the CT at the operating tap shall be adequate to prevent damage under maximum **fault** conditions and normal or **emergency** system loading conditions.

3.3.2.3 For **protection groups** to be independent, they shall be supplied from separate current transformer secondary windings.

3.3.2.4 Interconnected current transformer secondary wiring shall be grounded at only one point.

3.3.3 Voltage Transformer and Potential Device Criteria

Voltage transformers and potential devices associated with **Special Protection Systems** shall have adequate steady-state and transient characteristics for their intended functions.

3.3.3.1 Voltage transformers and potential devices shall have adequate volt-ampere capacity to supply the connected burden while maintaining their **relay** accuracy over their specified primary voltage range.

3.3.3.2 If a **Special Protection System** is designed to have multiple **protection groups** at a single location for redundancy, each of the **protection groups** shall be supplied from separate voltage sources. The **protection groups** may be supplied from separate secondary windings on one transformer or potential device, provided all of the following requirements are met:

. Complete loss of one or more phase voltages does not prevent operation of both SPS protection groups;
. Each secondary winding has sufficient capacity to permit fuse **protection** of the circuit;
. Each secondary winding circuit is adequately fuse protected.

3.3.3.3 The wiring from each voltage transformer secondary winding shall not be grounded at more than one point.

3.3.3.4 Voltage transformer installations should be designed with due regard to ferroresonance.

3.3.4 Battery and Direct Current (dc) Supply Criteria

dc supplies associated with a **Special Protection System** shall be designed to have a high degree of dependability as follows.

3.3.4.1 If a **Special Protection System** is designed to have multiple **protection groups** at a single location for redundancy, no single battery or dc power supply failure shall prevent the independent **protection groups** from performing the intended function. Each battery shall be provided with its own charger.

3.3.4.2 Each battery shall have sufficient capacity to permit operation of the **Special Protection System**, in the event of a loss of its battery charger or the ac supply source, for the period of time necessary to transfer the load to the other battery or re-establish the supply source.

3.3.4.3 The battery chargers and all dc circuits shall be protected against short circuits. All protective devices should be coordinated to minimize the number of dc circuits interrupted.

3.3.4.4 dc battery systems shall be continuously monitored to detect abnormal voltage levels (both high and low), dc grounds, and loss of ac to the battery chargers in order to allow prompt attention by the appropriate operating authorities.

3.3.4.5 **Special Protection System** dc supply circuits shall be continuously monitored to detect loss of voltage in order to allow prompt attention by the appropriate operating authorities.

3.3.5 Station Service ac Supply Criteria

If a **Special Protection System** is designed to have multiple **protection groups** at a single location for redundancy, there shall be two sources of station service ac supply, each capable of carrying at least all the critical loads associated with the **Special Protection System**.

3.3.6 Circuit Breakers Criteria

Where **Special Protection System** redundancy is achieved by use of independent **protection groups** tripping the same circuit breakers without overarming, each circuit breaker shall be equipped with two independent trip coils.

3.3.7 Teleprotection Criteria

Communication facilities required for **teleprotection** shall be designed to have a level of performance consistent with that required of the **Special Protection System**, and shall meet the following:

3.3.7.1 Where the design of a **Special Protection System** is composed of multiple **protection groups** for redundancy and each group requires a communication channel, the equipment and channel for each group shall be separated physically and designed to minimize the risk of more than one **protection group** being disabled simultaneously by a single event or condition.

3.3.7.2 **Teleprotection** equipment shall be monitored to detect loss of equipment and/or channel to allow prompt attention by the appropriate operating authorities.

3.3.7.3 **Teleprotection** systems shall be designed to assure adequate signal transmission during **bulk power system** disturbances, and shall be provided with means to test for proper signal adequacy.

3.3.7.4 **Teleprotection** equipment shall be powered by the substation batteries or other sources independent from the power system.

3.3.7.5 Except as identified otherwise in these criteria, the two **teleprotection** groups shall not share the same component. The use of a single communication tower for the radio communication systems used by the two SPS groups is permitted.

3.3.8 Physical Separation/Environment Criteria

3.3.8.1 In addition to the physical separation as referenced in sections 3.3.1.2 and 3.3.9.5, if a **Special Protection System** is designed to have multiple **protection groups** at a single location for redundancy, each separate protection group and **Teleprotection** of an SPS shall be on different non-adjacent vertical mounting assemblies or enclosures.

3.3.8.2 In the event a common raceway is used, cabling for separate groups of an SPS shall be separated by a fire barrier.

3.3.9 Grounding Criteria

Station grounding is critical to the correct operation of **Special Protection Systems**. The design of the ground grid directly impacts proper **Special Protection System** operation and probability of false operation from **fault** currents or transient voltages.

3.3.9.1 Each TO, GO and DP shall have established as part of its substation design procedures or specifications, a mandatory method of designing the substation ground grid, which:

. Can be traced to a recognized calculation methodology
. Considers cable shielding
. Considers equipment grounding

3.3.10 Provision for Breaker Failure Criteria

Type I SPS shall include breaker failure **protection** for each circuit breaker whose operation is critical to the adequacy of the action taken by the SPS with due regard to the power system conditions this SPS is required to detect. Options for breaker failure **protection**:

3.3.10.1 A design which recognizes that the breaker has not achieved or will not achieve the intended function required by the **Special Protection System** and which takes independent action to achieve that function. This provision needs not be duplicated and can be combined with conventional breaker failure schemes if appropriate.

3.3.10.2 Overarming the **Special Protection System** such that adequate action is taken even if a single breaker fails.

3.3.10.3 The redundancy afforded by actions taken by other independent schemes or devices.

3.3.11 Testing and Maintenance Criteria

3.3.11.1 Each SPS shall be maintained in accordance with the Maintenance Criteria for Bulk Power System Protection (Document A-4).

3.3.11.2 The design of an SPS both in terms of circuitry and physical arrangement shall facilitate periodic testing and maintenance.

3.3.11.3 Test facilities or test procedures shall be designed such that they do not compromise the independence of the redundant design aspects of the SPS.

3.3.11.4 An SPS shall be functionally tested when initially placed in service and when modifications are made.

3.3.11.5 If a segmented testing approach is used, test procedures and test facilities shall be designed to ensure that related tests properly overlap. Proper overlap is ensured if each portion of circuitry is seen to perform its intended function, such as operating a relay, from either a real or test stimulus, while observing some common reliable downstream indicator.

3.3.11.6 All positive combinations of input logic shall be tested regardless of the maintenance strategy used.

3.3.11.7 Sufficient testing shall be employed to ensure that timing races do not exist within hardwired or electronic logic, and that the SPS operating time is within design limits.

3.3.11.8 Each time the SPS is maintained, its hardware shall be tested in conjunction with the control facilities, related computer equipment, software and **operating procedures** to ensure compatibility and correct operation.

3.3.12 Analysis of SPS Performance

3.3.12.1 **Bulk power system** automatic operations shall be analyzed to determine proper **Special Protection System** performance. Corrective measures must be taken promptly if the **Special Protection System** or a **protection group** within the SPS fails to operate or operates incorrectly.

3.3.12.2 Event recording capability shall be provided to permit analysis of system operations and **Special Protection System** performance.

4.0 Measures and Assessments

None developed at this time.

Prepared by:	Lead Task Force- Task Force on System Protection
Review and Approval:	Revision to any portion of this Directory will be posted by the lead Task Force in the NPCC Open Process for a 45 day review and comment period. Upon satisfactorily addressing all the comments in this forum, the Directory document will be sent to the remaining Task Forces for their recommendation to seek RCC approval. Upon approval of the RCC, this Directory will be sent to the Full Member Representatives for their final approval if sections pertaining to the Requirements and Criteria portion have been revised. All voting and approvals will be conducted according to the most current "NPCC Inc. Bylaws" in effect at the time the ballots are cast. Revisions pertaining to the Appendices or any other portion of the document such as Links, Glossary Terms, etc., will only require RCC Member approval of the document. Errata may be corrected by the Lead Task Force at any time and provide the appropriate notifications to the NPCC Inc. membership. This Directory will be updated at least once every three years and as often as necessary to keep it current and consistent with NERC Regional Reliability Standards and other NPCC documents.
References:	NPCC RRS PRC-XXX-X (Future NPCC Regional Standard) Basic Criteria for Design and Operation of Interconnected Power Systems (Document A-2) Emergency Operation Criteria (Document A-3) Maintenance Criteria for Bulk Power System Protection (Document A-4) NPCC Glossary of Terms (Document A-7)

Attachment 1
Definition of Terms

Bulk power system - The interconnected electrical systems within northeastern North America comprising **generation** and transmission facilities on which **faults** or **disturbances** can have a **significant adverse impact** outside of the local area. In this context, local areas are determined by the Council members.

Contingency – An event, usually involving the loss of one or more **elements,** which affects the **power** system at least momentarily.

Fault – An electrical short circuit.

Permanent Fault — A fault which prevents the affected **element** from being returned to service until physical actions are taken to effect repairs or to remove the cause of the fault.

Transient Fault — A fault which occurs for a short or limited time, or which disappears when the faulted **element** is separated from all electrical sources and which does not require repairs to be made before the **element** can be returned to service either manually or automatically.

Operating Procedures -A set of policies, practices, or system adjustments that may be automatically or manually implemented by the system operator within a specified time frame to maintain the operational integrity of the interconnected electric systems.

Automatic Operating Systems — **Special protection systems**, remedial action schemes, or other operating systems installed on the electric systems that require *no intervention* on the part of **system operators**.

Normal (Precontingency) Operating Procedures — Operating procedures that are normally invoked by the **system operator** to alleviate potential facility overloads or other potential system problems in anticipation of a **contingency**.

Postcontingency Operating Procedures — Operating procedures that may be invoked by the **system operator** to mitigate or alleviate system problems after a **contingency** has occurred.

Protection -The provisions for detecting power system **faults** or abnormal conditions and taking appropriate automatic corrective action.

Protection group — A fully integrated assembly of **protective relays** and associated equipment that is designed to perform the specified protective functions for a power system **element**, independent of other groups.

Notes:

(a) Variously identified as Main **Protection**, Primary **Protection**, Breaker Failure **Protection**, Back-Up **Protection**, Alternate **Protection**, Secondary **Protection**, A **Protection**, B **Protection**, Group A, Group B, System 1 or System 2.

(b) Pilot **protection** is considered to be one **protection group.**

Protection system

Element Basis

One or more **protection** groups; including all equipment such as instrument transformers, station wiring, circuit breakers and associated trip/close modules, and communication facilities; installed at all terminals of a power system **element** to provide the complete **protection** of that **element**.

Terminal Basis

One or more **protection** groups, as above, installed at one terminal of a power system **element**, typically a transmission line.

Pilot **Protection —** A form of line **protection** that uses a communication channel as a means to compare electrical conditions at the terminals of a line.

Significant adverse impact — With due regard for the maximum operating capability of the affected systems, one or more of the following conditions arising from **faults** or **disturbances**, shall be deemed as having **significant adverse impact**:

a. instability;
- any instability that cannot be demonstrably contained to a well defined local area.
- any loss of synchronism of generators that cannot be demonstrably contained to a well-defined local area

b. unacceptable system dynamic response;
- an oscillatory response to a **contingency** that is not demonstrated to be clearly positively damped within 30 seconds of the initiating event.

c. unacceptable equipment tripping

- tripping of an un-faulted **bulk power system** element (element that has already been classified as **bulk power system**) under planned system configuration due to operation of a **protection** system in response to a stable power swing
- operation of a Type I or Type II **Special Protection System** in response to a condition for which its operation is not required

d. voltage levels in violation of applicable **emergency** limits;

e. loadings on transmission facilities in violation of applicable **emergency** limits;

Special protection system (SPS) – A **protection system** designed to detect abnormal system conditions, and take corrective action other than the isolation of faulted **elements**. Such action may include changes in **load**, **generation**, or system configuration to maintain system **stability**, acceptable voltages or power flows. Automatic underfrequency **load shedding** as defined in the *Emergency Operation Criteria* A-3, is not considered a **Special Protection System**. Conventionally switched, locally controlled shunt devices are not **Special Protection Systems**.

Teleprotection - A form of **protection** that uses a communication channel

Appendix A
Guidance for Consideration in SPS Design

Introduction

This Appendix provides the guidance for consideration in the implementation of the **Special Protection System** design criteria stipulated in Section 3.3 of this Directory.

The general objective for any SPS is to perform its intended function (generator rejection, load rejection, etc.) in a dependable and secure manner. In this context, dependability relates to the degree of certainty that the SPS will operate correctly when required to operate. Security relates to the degree of certainty that the SPS will not operate when not required to operate.

The relative effects on the **bulk power system** of a failure to operate when desired versus an unintended operation should be weighed carefully in selecting design parameters. For example, the choice of duplication as a means of providing redundancy improves the dependability of the SPS but can also jeopardize security in that it may increase the probability of an unintended operation. This general objective can be met only if the SPS can dependably respond to the specific conditions for which it is intended to operate and differentiate these from other conditions for which action must not take place.

Close coordination should be maintained among system planning, design, operating, maintenance and **protection** functions, since both initially and throughout their life cycle, SPSs are a multi-discipline concern.

2.0 Considerations Affecting Dependability

2.1 Redundancy is normally provided by duplication. Some aspects of duplication may be achieved by overarming, which is defined as providing for more corrective action than would be necessary if no failures are considered. The redundancy requirements for an SPS apply only with respect to its response to the conditions it is required to detect.

2.2 For a **Special Protection System** that is composed of multiple **protection groups**, the risk of simultaneous failure of more than one **protection group** because of design deficiencies or equipment failure should be considered, particularly if identical equipment is used in each **protection group**. The extent and nature of these failures should be recognized in the design and operation of the **Special Protection System.**

2.3 Area of common exposure should be kept to a minimum to reduce the possibility of all groups being disabled by a single event such as fire, evacuation, water leakage, and other such incidents.

3.0 Considerations Affecting Security

3.1 An SPS should be designed to operate only for conditions which require its specific protective or control actions.

3.2 **Special Protection Systems** should be no more complex than required for any given application.

3.3 The components and software used in **Special Protection Systems** should be of proven quality, as demonstrated either by actual experience or by stringent tests under simulated operating conditions.

3.4 **Special Protection Systems** should be designed to minimize the possibility of component failure or malfunction due to electrical transients and interference or external effects such as vibration, shock and temperature

3.5 **Special Protection Systems**, including intelligent electronic devices (IEDs) and communication systems used for **protection**, should comply with applicable industry standards for utility grade **protection** service. Utility Grade **Protection** System Equipment are equipment that are suitable for protecting transmission power system elements, that are required to operate reliably, under harsh environments normally found at substations. Utility grade equipment should meet the applicable sections of all or some of the following types of industry standards, to ensure their suitability for such applications:

- IEEE C37.90.1-2002 (oscillatory surge and fast transient)
- IEEE C37.90.1-2002 (service conditions)
- IEC 60255-22-1, 2005 (1 MHz burst, i.e. oscillatory)
- IEC 61000-4-12, 2001 (oscillatory surge)
- IEC 61000-4-4, 2004 (EFT)
- IEC 60255-22-4, 2002 (EFT)
- IEEE C37.90.2-2004 (narrow-band radiation)
- IEC 60255-22-3, 2000 (narrow-band radiation)
- IEC 61000-4-3, 2002 (narrow-band radiation)
- IEEE 1613 (communications networking devices in Electric power Substations)

3.6 **Special Protection System** circuitry and physical arrangements should be carefully designed so as to minimize the possibility of incorrect operations due to personnel error.

3.7 **Special Protection System** automatic self-checking facilities should be designed so as to not degrade the performance of the **Special Protection System**.

3.8 Consideration should be given to the consequences of loss of instrument transformer voltage inputs to **Special Protection Systems**.

3.9 Consideration should be given to the effect of the means of arming on overall security and dependability of the **Special Protection System**. Arming should have a level of security and dependability commensurate with the requirements of the SPS.

4.0 Considerations Affecting Performance

4.1 Control Cable, Wiring and Ancillary Control Device

Control cables and wiring and ancillary control devices should be highly dependable and secure. Due consideration should be given to published codes and standards, fire hazards, current-carrying capacity, voltage drop, insulation level, mechanical strength, routing, shielding, grounding and environment.

4.2 Environment

Means should be employed to maintain environmental conditions that are favorable to the correct performance of **Special Protection Systems.**

5.0 Operating Time of an SPS

Adequate time margin should be provided taking into account study inaccuracies, differences in equipment, and **protection** operating times.

6.0 Arming of an SPS

Arming is the selection, which may be external to the **Special Protection System**, of desired output action based on power system conditions and recognized contingencies. Arming requirements of a Special Protection System are normally based upon the results of system studies which take into account recognized contingencies, operating policies/procedures and current power system load/generation conditions. For a simple **Special Protection System**, arming may be an on/off function. A **Special Protection System** can be armed either automatically or manually.

6.1 Automatic arming is implemented without human intervention.

6.2 Arming manually if the recognition, decision or implementation requires human intervention. Sufficient time with adequate margin for recognition, analysis and the taking of corrective action should be allowed.

7.0 Maintenance Considerations

7.1 Additional periodic maintenance is recommended on the following **protection** equipment:

- On continuously monitored analog **teleprotection** channels, verify signal adequacy every twelve months.
- On non-monitored analog **teleprotection** channels, verify signal adequacy every month.
- On digital **teleprotection** systems, which are inherently monitored, verify local function

  every two years.
- On batteries and chargers, verify proper operation and general condition every month.
- On circuit breakers, verify ability to trip via each trip coil every two years, with due regard to critical trip paths between sensing relays and the breaker trip coils.

7.2 It is the responsibility of each TO, GO and DP to evaluate its own particular circumstances and determine if any additional maintenance should be performed on its system. More extensive maintenance may be required but not limited to:

- during the initial break-in period,
- where **protection** systems are exposed to abnormal conditions such as temperature extremes, vibration, corrosive atmosphere, etc.,
- when the operating condition of **protection** system control wiring is suspect..

7.3 The design of a **Special Protection System** both in terms of circuitry and physical arrangement should facilitate periodic testing and maintenance in a manner that mitigates the risk of inadvertent operation. As a **Special Protection System** may be complex and may interface with other protection systems or control systems, special attention should be placed on ensuring that test devices and test interfaces properly support a clearly defined maintenance strategy.

7.4 Proper overlap is ensured if each portion of circuitry is seen to perform its intended function, such as operating a relay, from either a real or test stimulus, while observing some common reliable downstream indicator.

7.5 Whenever practicable, some of the maintenance testing requirements may be met by analyzing and documenting the detailed performance of the **Special Protection System** during actual events to demonstrate that the specific testing requirements have been fulfilled. Such an approach can reduce the probability of false operation during maintenance while effectively reducing the extent of planned maintenance.

Appendix B
Procedure for Review of Special Protection Systems

Introduction

This Appendix provide the procedure to follow to obtain concurrence from NPCC if an entity concludes that a new **Special Protection System** or a modification of an existing **Special Protection System** will be required which affects the **bulk power system**. The procedure is also shown on the attached flow chart.

2.0 NPCC Review and Concurrence

2.1 Allowing for sufficient lead time to ensure an orderly review, the entity will notify the chairman of the Task Force on Coordination of Planning (TFCP) of its proposal to install a new **Special Protection System** or modify an existing **Special Protection System**. The entity will send copies of the complete notification to TFCO and TFSP. This notification will include statements that describe possible failure modes and whether misoperation, unintended operation or failure of the **Special Protection System** would have local, inter-company, inter-**Area** or inter-Regional consequences, when the **Special Protection System** is planned for service, how long it is expected to remain in service, the specific **contingency**(s) for which it is designed to operate and whether the **Special Protection System** will be designed according to the NPCC *Bulk Power System Protection Criteria* (Document A-5) and the *Special Protection System Criteria* and Standards requirements listed in this docment.

2.2 If the **Special Protection System** is expected to have only local consequences, TFCP will request that the Task Force on System Studies (TFSS) and the Task Force on System Protection (TFSP) review the proposal.

2.2.1 TFSP will be notified of the proposed **Special Protection System**. TFSP will advise TFCP of any concerns.

2.2.2 TFSS will review the analyses that the proposing entity has performed. A presentation may be required from the proposing entity. The purpose of the review will be to confirm that there are no adverse inter-**Area** or inter-Regional consequences of either a failure of the **Special Protection System** to operate when and how it is required or an inadvertent or unintended operation of the **Special Protection System**. If necessary, TFSS will request that the proposing entity conduct additional analyses.

2.2.3 If the TFSS review confirms the **Special Protection System** has only local consequences, TFSS will send the information to TFCP. If TFCP concurs, they will then notify the proposing entity of NPCC's conclusions that the **Special Protection System** has only local consequences. TFCP will also notify the Reliability Coordinating Committee (RCC), all the Task Forces, the Compliance Committee (CC), the proposing entity and other Members that concurrence has been given to the proposing entity to modify an existing **Special Protection System** or install a new **Special Protection System**, at which time, the **Special Protection System** may be deployed.

2.2.4 If the TFSS review concludes that the **Special Protection System** could have inter-**Area** or inter-Regional consequences, they will inform the TFCP. Upon receipt of the TFSS conclusion or if TFCP separately determines the **Special Protection System** could have inter-**Area** or inter-Regional consequences, TFCP will arrange for an overall NPCC review as detailed in Step 3.

2.2.5 TFSS will update the NPCC **Special Protection System** list/database.

2.3 If the proposing entity expects the **Special Protection System** to have inter-**Area** or inter-Regional consequences, or if the TFSS or TFCP review concludes this to be the case, TFCP will request the Task Force on Coordination of Operation (TFCO), the Task Force on System Protection (TFSP) and TFSS to review it. Each of the Task Forces may require a presentation from the proposing entity.

2.3.1 TFSP will confirm the failure modes of the **Special Protection System**, including actions of back-up **protection**, and whether or not the **Special Protection System** complies with NPCC system **protection** standards. TFSP will review whether the new or modified **Special Protection System** is in conformance with the NPCC *Bulk Power System Protection Criteria* (Document A-5) and the *Special*

Protection System Criteria and Standards requirments listed in this document and forward a summary of their findings to TFCO, TFCP and TFSS. This summary will include a statement as to whether the **Special Protection System** is in conformance with the *Bulk Power System Protection Criteria* (Document A-5) and the *Special Protection System Criteria* and Standards requirments listed in this document and whether the Task Force has any objections to its modification or installation.

2.3.2 TFSS will review the analysis that the proposing entity has performed. The purpose of the review will be to assess the **Special Protection System** is in conformance with the *Basic Criteria for Design and Operation of Interconnected Power Systems* (Document A-2) and to determine the inter-**Area** or inter-Regional consequences of either a failure of the **Special Protection System** to operate when and how it is required or an inadvertent or unintended operation of the **Special Protection System**. If necessary, TFSS will request that the proposing entity conduct additional studies. When their review is completed, TFSS will forward a summary of their findings to TFCO, TFCP and TFSP. This summary will include a statement as to whether the **Special Protection System** is in conformance with the *Basic Criteria* (A-2) and whether the Task Force has any objections to its modification or installation.

2.3.3 TFCO will review the operability of the **Special Protection System** and forward a summary of their findings to TFCP, TFSS and TFSP. This summary will include a statement as to whether the Task Force has any objections to its modification or installation.

2.3.4 TFCP will prepare an overall summary for the RCC. This summary will include the findings of the other Task Forces and whether there are any objections to the modification of the existing **Special Protection System** or the installation of the new **Special Protection System** and as a minimum, include the following information:

- Function, i.e. GR-generation rejection etc.
- Identification
- Initiating condition
- Action(s) resulting
- Name of the **Special Protection System**, and owner, identification number
- Arming, i.e. percentage of time, system conditions for which it's needed, manual vs. automatic, etc.
- Reason for the installation
- Comments, explanations, such as "temporary until such time…"
- Company, owner
- SPS Number, drawn by NPCC staff
- Current Status, i.e. New, Changed or Removed
- Type Determination

- Determinations of the Task Forces' analyses
- Consequences of operation, misoperation and failure to operate
- Approximate of load or generation rejected by **Special Protection System** operation
- Proposed date of deployment
- Proposed date of retirement/deactivation

2.3.5 The RCC will review the summary report and act on the proposal to modify an existing **Special Protection System** or install a new **Special Protection System**. The RCC may also remand the review of the **Special Protection System** back to the TFCP if further analyses are determined to be needed.

2.3.6 The TFCP will notify the RCC, all the Task Forces, the CC, the proposing entity and other Members of the outcome of the review. Upon NPCC approval of the type and compliance with Criteria, the **Special Protection System** may be deployed.

2.3.7 The TFSS will then update the NPCC **Special Protection System** list/database.

3.0 Presentation and Review of Special Protection Systems

Each new or modified Type I or Type II **Special Protection System** shall be reported to the Task Force on System Protection in accordance with the following presentation and review procedure.

3.1 A presentation will be made to the TFSP on new facilities or a modification to an existing facility when requested by an NPCC Member or the TFSP.

3.2 A presentation will be made to the TFSP when the design of the **protection** facility deviates from the *Bulk Power System Protection Criteria* (Document A-5).

3.3 A presentation will be made to the TFSP when an NPCC Member is in doubt as to whether a design meets the *Protection Criteria*.

3.4 Data Required for Presentation and Review of Proposed **Special Protection System:**

3.4.1 The TO, GO or DP will advise the TFSP of the basic design of the proposed system. The data will be supplied on the attached forms, accompanied by a geographical map, a one-line diagram of all affected areas, and the associated **protection** and control function diagrams. A physical layout of **protection** panels and batteries for the purpose of illustrating physical separation will also be included.

3.4.2 The proposed **protection** system will be explained with due emphasis on any special conditions or design restrictions existing on the particular power system:

3.5 Procedure for Presentation:

3.5.1 The TO, GO or DP will arrange to have a technical presentation made to the TFSP.

3.5.2 To facilitate scheduling, the chairman of the TFSP will be notified approximately four months prior to the desired date of presentation.

3.5.3 Copies of materials to be presented will be distributed to TFSP members 30 days prior to the date of the presentation.

3.6 Review by TFSP

The TFSP will review the material presented and develop a position statement concerning the proposed **protection** system. This statement will indicate one of the following:

3.6.1 The need for additional information to enable the TFSP to reach a decision.

3.6.2 Acceptance of the TO, GO or DP statement of conformance to the *Protection Criteria*.

3.6.3 Acceptance of the submitted proposal.

3.6.4 *Conditional acceptance of the submitted proposal.

3.6.5 *Rejection of the submitted proposal

* Position Statements to include an indication of areas of departure from the intent of the *protection criteria* and suggestions for modifications to bring the **protection** system into conformance with the NPCC criteria.

3.6.6 The results of the TFSP review will be documented in the following manner.

. A position statement will be included in the minutes of the meeting at which the proposed **protection** system was reviewed.

. If necessary, a letter outlining areas of nonconformance with the NPCC *Protection Criteria* and recommendations for correction will be submitted to the TO, GO or DP.

. The Task Force will maintain a record of all the reviews it has conducted.

PROCEDURE FOR NPCC REVIEW OF NEW OR MODIFIED BULK POWER SYSTEM SPECIAL PROTECTION SYSTEMS (SPS)

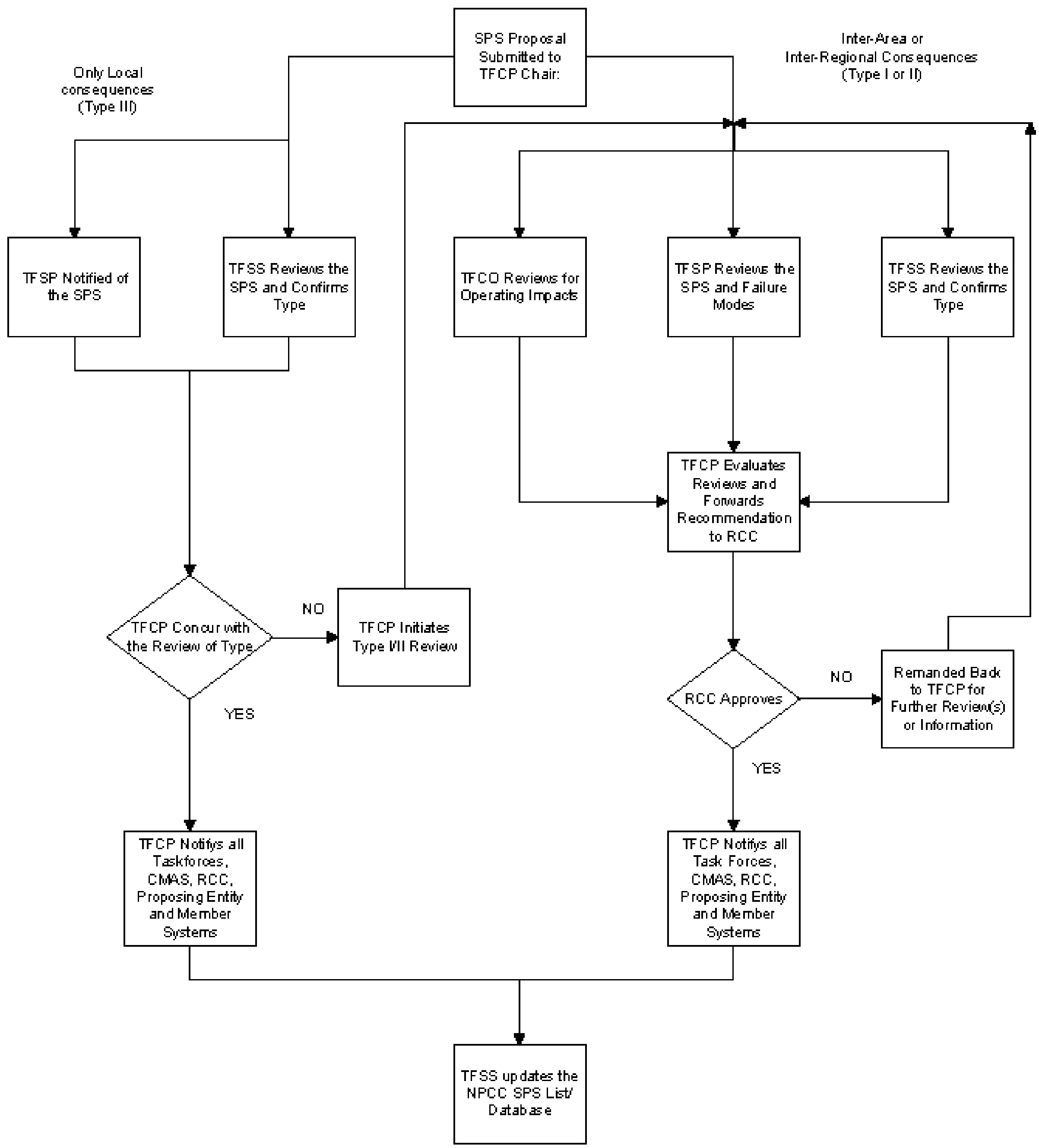
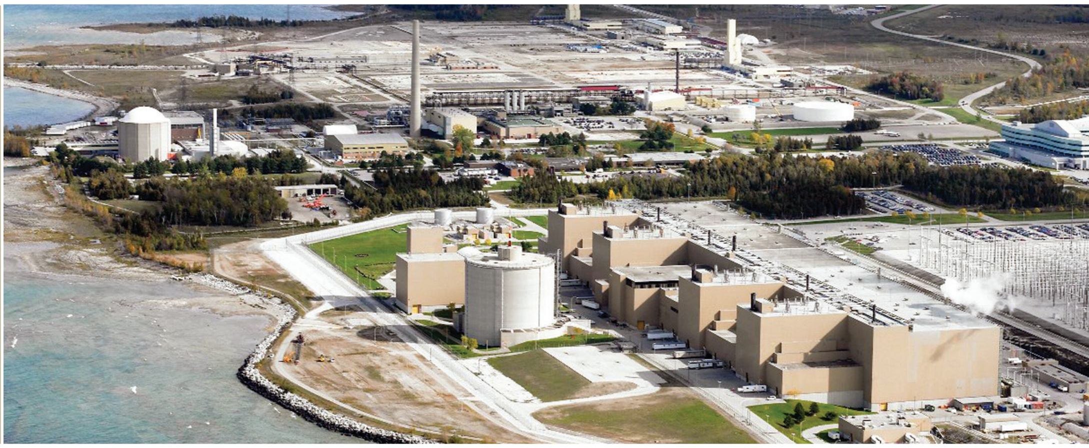


Exhibit No. 3

Special Review for the Minister of Energy

The Bruce Power Refurbishment Agreement



Office of the Auditor General of Ontario

contract is signed." No financial audit was done to confirm the amount, however.

- Ontario Energy Board staff were not asked to confirm the $2.75-billion estimate.
- In September 2005, the Ministry asked the IESO for its opinion on the reasonableness of the $250-million cost increase given that Bruce A LP had itself indicated earlier to the Ministry that contract cost increases would be substantially less than $250 million.

Given that the $250-million increase added as much as $1.56/MWh to the support price, we were concerned that such a significant increase in cost between May 2005 and September 2005 was not substantiated, especially with respect to the fixed-price contracts, which accounted for 70% of the total costs.

We were also concerned about the fact that, if the actual costs come in at the June 2005 estimate of $2.5 billion, ratepayers will still pay about $2.7 billion (since the support price is based on $2.75 billion and the cost-sharing formula is structured to allow only $50 million of the excess payment to be recovered). We understand that actual costs incurred will be audited by the OPA, but the results of these audits will not have any impact on the sharing formula agreed to.

Provisions for Unit 3

The capital cost for refurbishing Unit 3 was set at $1.15 billion in the Refurbishment Agreement. This cost included a significant allowance for contingencies, which is included in the financial model used to calculate the support price. However, under the terms of the Refurbishment Agreement, if the cost comes in under $1.15 billion but more than the estimate before contingencies, Bruce A LP will keep most of the "savings" under $1.15 billion, with ratepayers getting between 0% and 50% through adjustments to the support price. Ratepayers therefore obtain little benefit if the contingency allowance is not spent.

Provisions for Unit 4

The total cost of replacing the steam generators was estimated to be $350 million. Months before Bruce Power approached the province with its refurbishment proposal, Bruce Power had already received approval from its Board of Directors to purchase these steam generators to avoid losing $2 billion of revenue in the event of Unit 4 being prematurely shut down.

Our review of the financial model indicated that the cost of the replacement had been properly included in the non-refurbishment scenario of the financial model and was not assumed by ratepayers. However, there is a provision in the Refurbishment Agreement whereby the OPA and Bruce A LP are to share the excess cost if the generators cost more than $350 million. Since Bruce Power's decision to replace the steam generators, made to avoid losing $2 billion in revenue, predated the refurbishment proposal, we questioned why ratepayers should share the risk of cost overruns.

OTHER MATTER

Transmission Capacity

There is a "deemed-generation" provision in the agreement that allows Bruce Power and Bruce A LP to get paid without generating electricity. Specifically, if a lack of transmission capacity to support the flow of electricity from the Bruce plants to the power grid prevents the plants from generating electricity, the OPA will have to pay Bruce Power and Bruce A LP the market price for the electricity it would otherwise have generated.

If a unit or units have to be shut down due to lack of transmission capacity in the Bruce Peninsula, it is understandable that Bruce receive some compensation for underutilized capital facilities, as well as for some variable costs that would undoubtedly be incurred. However, Bruce is to receive the full market price for any lost production caused by insufficient transmission capacity. We have the following observations with respect to this:

- If the units are not operating Bruce will have some, and perhaps significant, savings in their variable costs and accordingly we would have expected there would have been a reduced price paid for electricity not generated by an idled unit. By paying the full market price, our concern is that Bruce will have a higher profit margin when the plants are not operating than when the plants are operating.
- Even though the agreement is for energy output from the Bruce A units, ratepayers are required to pay Bruce Power—a separate ownership group—for deemed generation from the Bruce B units. In addition, the payments for the energy not produced are "to be attributed in whole first to Bruce B" units, with any excess deemed-generation payments to be subsequently attributed to Bruce A units. The Ministry itself stated that "there is no way to determine which option [paying Bruce A or Bruce B first] would place the Province in a better (or worse) position." Since Bruce B was never entitled to any such "deemed-generation" payments under the existing agreement, we do not see what benefit ratepayers received for providing this protection to Bruce Power now.
- If the lack of transmission capacity results in electricity shortages, this will likely cause the market price to escalate significantly. Therefore, Bruce B will reap this much higher market price. For instance, in summer 2005, when hurricanes hit the Gulf of Mexico and took out significant natural gas capacity, electricity prices temporarily soared to a range of $70/MWh–$80/MWh. We are not convinced the Refurbishment Agreement sufficiently mitigates this risk to the ratepayers. A more reasonable price from the ratepayers' perspective would be the guaranteed floor price of $45/MWh (adjusted for inflation) for Bruce B's deemed-generation output if Bruce B units need to be idled due to lack of transmission capacity.

We understand that current transmission capacity will not be sufficient to support all the energy to be produced by the eight units of Bruce plants A and B. Ministry staff indicated to us that they were well aware of this potential issue and that the risk of transmission inadequacy will exist only if all eight Bruce units are generating output. To help mitigate this risk, a provision in the refurbishment agreement states that no deemed generation for output from an eighth unit is to be allowed prior to 2012. We were also advised that the IESO has made plans to accommodate the return to service of the Bruce A Units 1 and 2, as well as the additional electricity produced from emerging, renewable-source, wind-generation capacity in the Bruce Peninsula.

While we understand from the Ministry that Hydro One is currently preparing an application for the construction of a new transmission line, the work that the IESO has identified as needing to be done in conjunction with such construction is not guaranteed to proceed as planned, since some of it must be assessed for environmental impact and must receive the approval, after consultation, of local communities spread across a wide geographic area. Therefore, we believe that, particularly in light of the deemed-generation provisions in the Refurbishment Agreement, it is essential that the Ministry continue to address the risk that there may not be sufficient transmission capacity. The Ministry advised us that it has a number of initiatives under way to mitigate the risk of insufficient transmission capacity and therefore having to pay the Bruce partnerships for power not produced.

Exhibit No. 4

ONTARIO ENERGY BOARD

FILE NO.: **EB-2007-0050**

VOLUME: **Technical Conference**

DATE: **October 15, 2007**

Let me start off with talking about what generation is up there right now. Presently there are six units operating at the Bruce complex, two units at the A plant, four units at the B plant. The total plant output is 4734 megawatts, and it comprises 1500 megawatts from the A plant and 3234 megawatts from the B plant.

In addition to the nuclear generation in the Bruce area today, there is also about 15 megawatts of wind generation operating currently. So altogether, the generation capacity in the Bruce area today totals about 4749 megawatts.

Between now and 2013, OPA is forecasting a substantial increase in the amount of generation being added to the Bruce area. The specific development included in the forecast I will discuss below.

First is the return of the refurbishment of Bruce 1 and 2 in 2009-2010 time frame. This will add about 1500 megawatts of nuclear generation to the system from the Bruce area.

Second, Bruce B. Bruce Power is planning to upgrade the output of the Bruce B units - the four units at the Bruce B plant - to 850 megawatts. They're currently running below that level. The total increase on the Bruce plant, when it is all completed, will add 166 megawatts to the system in the Bruce area, and that work is currently scheduled between 2008 and 2013.

In addition to the Bruce development being forecast, there are also, under the renewable energy supply 1 and renewable energy supply 2 procurement programs. This is renewable-generation procurement. There are major wind developments expected to come in service between 2007 and 2009, totalling about 675 megawatts.

In addition, with the renewable-energy standard-offer program, there have been 10 megawatts of wind generation contracts given to those 10 megawatts that will be coming in service around 2009. Altogether, this will add over 2351 megawatts of generation in the Bruce area by 2013.

This will increase the total generation to about 7100 megawatts, of which the majority has been committed.

Furthermore, as part of the effort in meeting the government directive on renewable generation, which is a target of 15,700 megawatts in Ontario by 2025, the OPA has identified and planned for another thousand megawatts of economic wind generation in the Bruce area for in-service by around 2014.

The thousand megawatts that we are forecasting for future wind generation consists of 300 megawatts of standard offer program and about 700 megawatts of large wind developments.

With regard to standard-offer-program estimate, currently Hydro One connection queue, there is over 700 megawatts of standard offer seeking connection studies in the Bruce area.

The distribution capability limits the amount that can be added to the distribution in the Bruce area to about 300 megawatts. If not for what we call the orange zone generation by cleaner resources, and strengthening the transmission system to promote system efficiency and congestion reduction.

In 1985, the system at that time was designed to be adequate for eight units at Bruce for the condition of the study at that time. So why is today's system only adequate for six units?

Mike's presentation indicated the variability in the condition and the operation of the system in southwestern Ontario. A key aspect of the changes that occurred from 1985 to now is the changes in the reference system power flow patterns. Back in 1985, much of the concern was an east-to-west flow. This is a power flow from the GTA and Bruce into London and flowing from London toward the Sarnia and Windsor area.

Now the system is changed to consider a west-to-east flow. This is from the Sarnia and Windsor area into London and toward the GTA. The reason for that? There is a lot of additional gas generation added in the Sarnia and the Windsor area. There is quite a large amount of renewable generation added also in that part of the system, as well as co-gen standard offer. Also, in many locations, Ontario is dependent on the import from the US for capacity support. All these factors increase the transfer from west to east.

With that change, it changed the dynamic of the system very significantly. When the study was done, it was for an east-to-west flow. The dominating failure mode at that time was a plant's instability at the Bruce. It also was subsequently identified to be also area-mode stability issues, both related to Bruce and the interconnected system.

Based on IESO's analysis of the system, the dominating failure mode for today's system in southwestern Ontario and the Bruce is voltage instability event, which is very different in characteristic than a machine or plant mode instability.

One, the reactive situation in the rest of the system, especially in the receiving end in the GTA, in the Kitchener area, impacts on the transfer limit of Bruce. Also, the many factors, such the as number of generators in service in southwestern Ontario, such as Nanticoke, such as Lambton, also impacts on the ability to support the voltage on heavy transfers.

So all of that changed the capability of the system to deliver power out of Bruce down by two units, more or less. So now, the system is adequate for six, not for eight units.

There is also another point. At the time, in the mid-1980s, there was a heavy-water plant in operation at the Bruce complex. At its peak, when all three heavy-water plants were operating, it was up at 300 megawatts, or so. None of the heavy-water plants are now in operation at the Bruce. So without local load, the additional generation produced at the Bruce is delivered to the system.

At this point, I will discuss the next part of the resources in southwestern Ontario. Those are shrink capacitors and possibly SBCs. They are there to regulate the voltage as we transfer more and more power out of the Bruce area using the existing system.

Also, there is a need to upgrade the Hanover-to-Orangeville 230 kV line. There is a local limitation there, and upgrading that 230 kV line will relieve the bottleneck on the 230 kV system. It can also be done by about 2009.

With both measures, that will increase the capability of the Bruce system, the existing system, up by another 400 megawatts.

So the next figure indicates, on the completion of the near-term measures, that the capability now is up to about 5400 megawatts, that dotted blue line.

At this point, we still have a gap in capability for 2009 to just about the end of 2010.

So we consider, now, a number of interim measures. The difference with the near-term measure is that with interim measures, after the line comes in service, there is no longer a need to have interim measures. It is only for the time between when you have a gap and when the line comes in service.

We have three measures identified for that. One is a non-transmission option. This consists of not granting contracts for generation developments in the Bruce area under the standard-offer program until the line is in service. It is in effect right now. Its term is the "orange zone", for most of you that is aware of this.

That is one measure.

The second one is expanding the Bruce special protection system. This is not a new system. It has been in effect since the mid 1980s, the current scheme. What it will do, you need to expand it to provide additional coverage so that you could trigger generation rejection in the event of those contingencies. And generation rejection in the interim periods would be used to maximize transfer capability at all times, not just under all those conditions.

Thirdly, consider the installation of series capacitors to further increase the transfer capability. The information from Hydro One is that the earliest that can come in service is 2011. Its need is still under consideration. It costs $150 million of investment for the installation of the series capacitors that we are contemplating, which is a bank on the Bruce-Longwood line and a bank or two banks on the Bruce-Longwood circuits and one bank on the Longwood-to-Nanticoke circuits. It also requires extensive changes in the design and operation of the Bruce transmission system in incorporating such a device on to the system.

With the near-term and interim -- the capability of the system as shown by the green dotted line here -- now this is what the interim measure, the first two interim measures which is the orange zone definition and also GR, but not series compensation. The green line indicates that

MR. GIBBONS: Right.

MR. CHOW: So I'm not quite sure what exactly you try to verify.

MR. GIBBONS: In my question, I'm an economist and I'm assuming I've got 7400 megawatts coming down to Toronto, potentially.

MR. CHOW: Right.

MR. GIBBONS: I'm trying to figure out what are the incremental economic benefits to this province of building that new line. I am asking you, given we've already got the existing line up to 7400 megawatts, will this new line actually bring more megawatts of power from the Bruce area to Toronto? Or will it bring either megawatts or megawatt hours?

MR. CHOW: I think there is a number of assumptions you made here is: One, you will continue in the long run using generation rejection, which we portray as an interim measure, not as a long-term measure.

So during the interim period, it is being used, but in the long run it is really another replacement for a transmission line.

Now, you also make the assumption that series compensation is added. Series compensation has a cost. Series compensation is very lossy as a system. Series compensation requires a particular more complex operation of the system.

So there are values in putting a transmission line in. One, it provides the 8400 or 8200 megawatts of capacity.

Exhibit No. 5

Fallis INTERROGATORY #26 List 1

Interrogatory

Issues:

1.1. Has the need for the proposed project been established?

1.3. Have all appropriate project risk factors pertaining to the need and justification (including but not limited to forecasting, technical and financial risks) been taken into consideration in planning this project?

1.4. Is the project suitably chosen and sufficiently scalable so as to meet all reasonably foreseeable future needs of significantly increased or significantly reduced generation in the Bruce area?

Ref. B/Tab 1 /Sch3

Preamble:

Statement by HON1 - (p. 1, line 25 - 28, and p. 2, line 1-14)

HONI states that the present transmission system from the Bruce has the capability to transmit about 5,000 MW of the generation from the Bruce area.- and that there is a shortfall of 3,100 MW in needed transmission capacity.

Ref. Bruce Power New Build Project -for Bruce "C" - Application for construction at the Bruce of a 4,000 MW - 4 Nuclear Reactor Power Generation system - as submitted to the Canadian Nuclear Safety Commission in December of 2006, with a request to approve a full 3 year environmental impact study;

Preamble:

The Project Description by Bruce Power proposes to have the Bruce "C project generating power initially in January of2015 adding one of4 reactors in each year thereafter for completion in 2019, From 2011 the continuing maximum generation capacity at the Bruce will be about 6,400 MW until January 2026 with Bruce "C" being brought into service in January of 2015

Ref B/Tab 6/Sch2 - IESO REP – 0382

B/Tab 6/Sch4 - IESO The Ontario Reliability Outlook, March, 2007 ('ORO')

Preamble:

System Impact Assessment Report - March 27, 2007 of IESO:

This SIA Report does not make any statement or calculation anywhere therein the of combined transmission capacity, expressed in MW of the three existing 230KV and two 500KV Transmission Lines but refers only to the fact, (p. 1 - para. 1),that the new 500 KV line will have no materially adverse effect on the IESO-controlled grid.

The SIA Report states (p. 11 - para. 9), that the construction ofthe new 500 KV line is intended to allow additional generating capacity to be incorporated beyond the eights units at the Bruce complex and all of the committed wind turbine projects...

The SIA Report does not make any schematic or analytical provision therein to receive at the Bruce Complex or elsewhere in grid system the any of the committed or projected wind-generated electrical power for transmission to any of the 230KV or 500KV transmission lines, existing or projected, nor makes any recommendations for the construction at the Bruce Complex or elsewhere of any switchyard facilities to whatsoever to accommodate the receipt and transmission ofcommitted or projected wind-generated electrical power.

In March 2007 ORO, (at p. 3 - Transmission), the IESO stated that a new 500KV line out of the Bruce is required as soon as possible to accommodate, additional generation expected from the new projects and the refurbished Bruce nuclear units. That ORO Report fails to state what are the present transfer capabilities levels ofthe existing 5 transmission lines, and what the transfer capability levels must attain, expressed in MW.

Preamble:

An Assessment of the Adequacy of Generation and Transmission Facilities to Meet Future Electricity Needs in Ontario - 10 year Outlook – January 2006 to December 2015 - dated August 2005

This Report was prepared by IESO in August 1995, contemplating the return to service of Units 1& 2 at Bruce "A" GS of 1,500 MW and was specifically produced to provide an assessment of the demand-supply picture for the province and to provide a plan identifying the timing and requirements for system changes needed to meet the Ont. Govt's coal shutdown timeframe, (P. iii).

This 86 page comprehensive Report of the IESO concluded that series capacitors, a new shunt capacitor and a conversion ofcertain Nanticoke Units to synchronous condenser should be sufficient to enhance transfer capability of the existing transmission facilities to allow Units 1 & 2 at Bruce 'A' GS to be incorporated without the need for any new transmission line, (P. 27).

Preliminmy IESO studies indicate that the proposed 500KV series capacitors on the lines emanating from the Bruce Complex should sufficiently enhance the transfer capability of the existing transmission facilities to allow the additional capacity at Bruce GS to be incorporated without the need for any new transmission lines

A.2 Bruce "B" Nuclear Facility

a) What is the actual maximum 'net generating capacity' of each of each of Units '1', '2', '3' and '4' of Bruce 'B' expressed in MW/h. (. (The Auditor General of Ontario determined in April, 2007 in his Report on the Refurbishment Agreement between Bruce Power and the OPA made October 17th 2005, that each Unit ofBruce 'A' had an authorized net generating capacity of 785 MW/h) ? In the IPSP Discussion Paper # 5 - Transmission produced by the OPA , filed as Exhibit b, Tab 6, Schedule 5, Appendix 5, & on page 44 thereof the OPA states that each ofUnits 1,2,3 & 4 of Bruce 'B' have a generation capacity of 890 MW/h.

b) Which statement as to the production capacity of each of Units1, 2, 3 & 4 of Bruce 'B' is wrong? and

c) has he OPA taken steps to correct the wrong information disseminated by the Auditor General of Ontario, or has the OPA stated the wrong production capacity of each of Units1, 2, 3 & 4 of Bruce 'B' and so advised the OEB and participants and interveners in this proceeding.

Response

a) According to the technical conference presentation slide 14 and 15, the current net generating capacities of the Bruce B units are a combined 3,234 MW (for an average capacity of 808 MW per unit). Each Bruce B unit is intended to be upgraded such that each has a net generating capacity of 850 MW.

b) The most up to date numbers were presented at the technical conference.

c) The OPA believes that the information provided in part (a) is the most current.

Exhibit No. 6

Energy Probe INTERROGATORY #20 List 3

Interrogatory

Ref: Exh. B/T 1/S 1 p. 3
Exh. B/T 3/S 1 p. 1
Issue 1.1: Has the need for the proposed project been established?

In two or more references (above), the Applicant has made vague assertions about the amount of electricity potentially to be supplied from the Bruce A site, to wit: "In 2009 Bruce Power is expected to return to service two 750 MW units at Bruce A …; Bruce Power will be removing one [in the same year], and 'later' one additional, (sic) of the operating 750 MW units from the Bruce A plant for refurbishment." What specifically and concretely in quantitative terms is the plan for additional electricity supply coming out the Bruce site in 2009?

Response

Please refer to the "Bruce Power" area (shaded blue) in Exhibit B Tab 1 Schedule 1 Page 4 Table 1 (Hydro One's updated evidence of March 25, 2008) attached to this response as Attachment A. This graph indicates the expected amount of nuclear power from 2007 to 2014. An incorrect graph was inadvertently filed in the November 30, 2007 update.

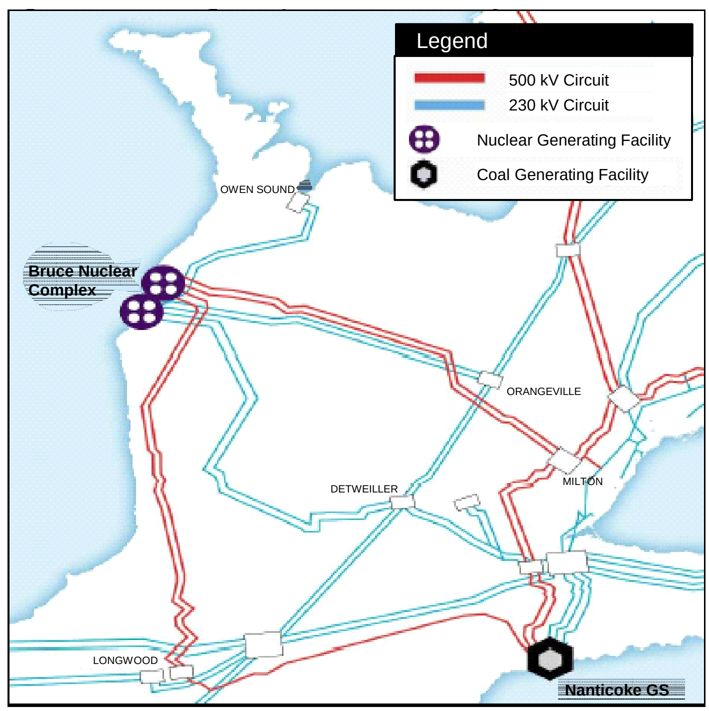
Attachment A

Exhibit B, Tab 1, Schedule 1
Page 3 and 4

PROJECT LOCATION AND EXISTING TRANSMISSION SYSTEM

1.0 PROJECT LOCATION

The transmission project described in Exhibit B, Tab 2, Schedule 1 is located in southwestern Ontario. The transmission elements of this project extend from the Bruce Power Complex on the eastern shore of Lake Huron (north of Kincardine) to west of Orangeville in Dufferin County, and continue to Hydro One's Milton Switching Station (SS) in the western Greater Toronto Area (GTA). The route passes through four counties and one regional municipality (Bruce, Grey, Wellington, Dufferin, and Halton, respectively) and eleven municipalities (Kincardine, Brockton, Hanover, West Grey, Southgate, Wellington North, Erin, East Luther Grand Valley, East Garafraxa, Halton Hills and Milton). A detailed map of the project location and the existing transmission facilities is provided in Exhibit B, Tab 1, Schedule 2.



Source: OPA

2.0 EXISTING TRANSMISSION FACILITIES IN SOUTHWESTERN ONTARIO

Southwestern Ontario is the area of southern Ontario that lies to the west of the GTA and Barrie. This area has a number of large generating stations such as Bruce, Nanticoke, Lambton (and Beck in the Niagara area) with a total of approximately 15,000 MW of generation. The area also includes major load centers such as Hamilton, Windsor and Kitchener-Waterloo-Cambridge-Guelph. Table 1 summarizes generation, peak demand and interconnection capability in southwestern Ontario during the summer of 2005.

Table 1: Generation, Load and Interconnection Capacities in SW Ontario (2005)

Generation (MW)		**Loads (MW)**	
Bruce	5,060	Windsor/Essex	1,000
Nanticoke	3,945	Sarnia	800
Lambton	1,972	London	750
Beck	2,006	KWCG	1,400
Windsor area gas	739	Hamilton	1,300
Sarnia	510	Woodstock/Ingersoll	195
Other	746	Brantford/Brant	250
		Niagara	1,020
		Other	2,100
Total Generation	14,978	Total Load	8,815
Interconnections Capability			
Michigan		**New York at Niagara**	
Import – Summer	1,550	Import - Summer	1,300
Export – Summer	1,950	Export - Summer	1,300
Import – Winter	1,750	Import – Winter	1,650
Export – Winter	2,200	Export - Winter	1,950

Source: OPA, Ontario's IPSP Discussion Paper #5

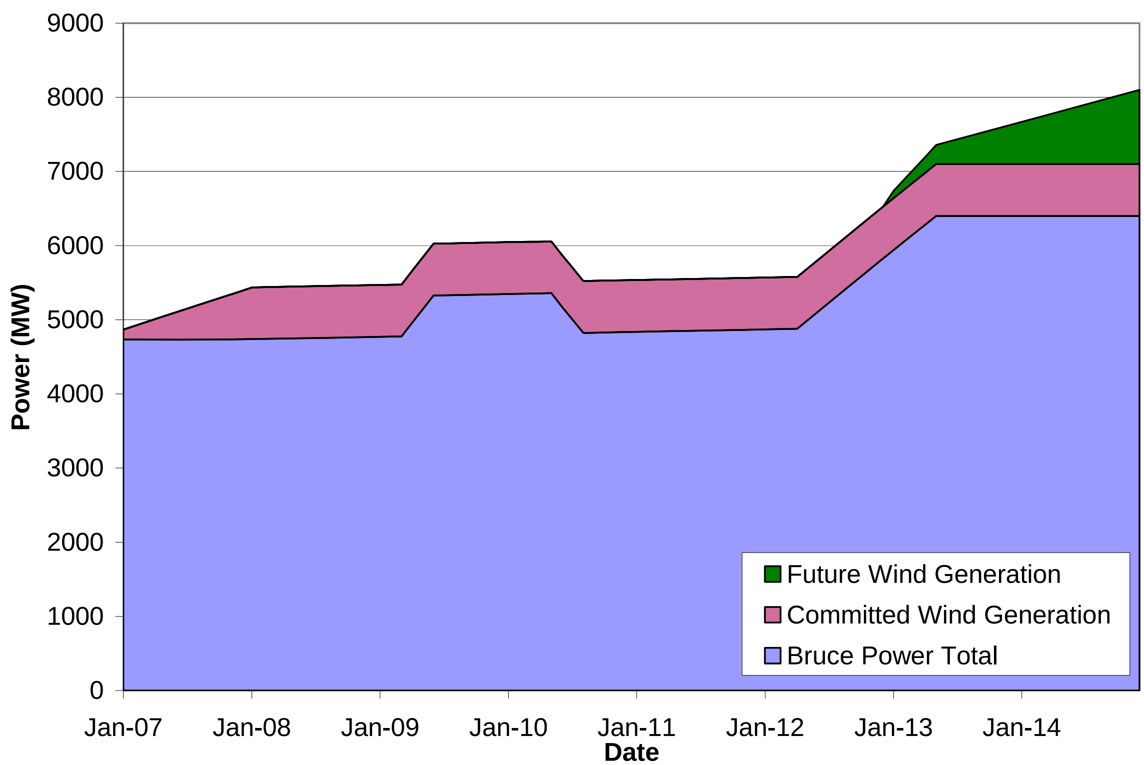
The transmission assets in southwestern Ontario connect the major generation and load centers in the region to the interconnected grid. Almost half of the generating capacity in the region supplies the energy needs of other parts of the province. Furthermore, the Bruce Power Complex currently provides approximately 20% of the Province's peak power needs. The transmission facilities in this area are designed and placed to support this concentration of generation capacity, respecting physical constraints such as system and voltage stability, and thermal limits. This is a tightly interconnected system, where the availability and performance of each major element (especially the 500 kV facilities) can affect the integrity of the entire network and neighbouring jurisdictions.

2.1 Generation Resources in the Bruce Area

The generation capacity at the Bruce Power Complex currently totals 4,700 MW. By 2009, a total of 700 MW of existing and committed wind generation through the Provincial Government's renewable energy initiatives will bring the total generation capacity in the Bruce area to 5,400 MW. In 2009 Bruce Power is expected to return to service two 750 MW units at Bruce A that are currently being refurbished under a contract with the Ontario Power Authority (OPA). At the same time, Bruce Power will be removing one, and later one additional, of the operating 750 MW units from the Bruce A plant for refurbishment. By 2013, the refurbishment work of these units will be completed and the total committed generation in the Bruce area will increase to 7,100 MW. This schedule reflects the amended contract between Bruce Power and the OPA announced in August, 2007. Please see Exhibit B, Tab 6, Schedule 5, Appendix 1, page 2 for more information.

As part of the development of the Integrated Power System Plan (IPSP), the OPA's Transmission Discussion Paper No. 5 (pages 39-53) indicates that there is considerable potential for additional renewable generation, particularly wind generation, in the Bruce area. Another 1,000 MW of wind generation is expected, for a total of about 8,100 MW in this area (refer to Exhibit B, Tab 6, Schedule 5, Appendix 5). Figure 1 illustrates OPA's forecast generation in the Bruce area from 2007 to 2014.

Figure 1: Bruce Area Available Generation (2007 – 2014)



Source: OPA

2.2 Transmission Resources in Southwestern Ontario

The generation from Bruce Power Complex and the existing Bruce area wind generation are currently incorporated into the grid via 500 kV and 230 kV transmission lines as follows:

- The 500 kV Bruce x Milton SS and Claireville TS double-circuit tower line, B561M and B560V;
- The 500 kV Bruce x Longwood TS double-circuit tower line, B562L and B563L;

- The 230 kV Bruce x Orangeville TS double-circuit tower line, B4V and B5V;
- The 230 kV Bruce x Detweiler TS double-circuit tower line, B22D and B23D; and,
- The 230 kV Bruce x Owen Sound TS double-circuit tower line, B27S and B28S.

Major 500 kV facilities in southwestern Ontario include 500 kV transformer or switching stations at the Bruce Power Complex, Milton SS, Longwood TS (west of London), Nanticoke GS (east of Port Dover), and Middleport TS (east of Brantford). A detailed map of the existing transmission facilities is provided in Exhibit B, Tab 1, Schedule 2.

Depending on the load, generation and import patterns, these circuits have about 5,000 MW of transmission capacity to deliver the output from the Bruce Power Complex and the existing wind generation. The maximum transmission capacity is based on applicable reliability standards (Northeastern Power Coordinating Council ("NPCC"), North American Electric Reliability Council ("NERC")) and the planning assumption that with all remaining circuits in-service, the power system performance should satisfy required criteria and guidelines following the loss of any of the double-circuit lines (first contingency).

In summary, the present-day transmission system has the capability to transmit the currently available generation from the Bruce area, but is not sufficient to transmit the additional generation that is committed and planned for the area.

Energy Probe INTERROGATORY #21 List 3

Interrogatory

Ref: Exh. B/T 1/S 1 p. 4
Issue 1.1: Has the need for the proposed project been established?

It appears from Figure 1: Bruce Area Available Generation (2007-2014) that there may be "700" additional megawatts of electricity planned to be transmitted from the Bruce site in 2009 with precisely the same amount of electricity being reduced in early 2010, and not recaptured until 2012. Why is this transmission project being initiated in 2008 and its approval expedited over the next few months when there is no effective, lasting demand for such a transmission project until 2012 – which also assumes no effective provincial CDM initiatives are in play?

Response

In Figure 1 referenced above, the net increase in the amount of Bruce Area generation above today's 4,800 MW level is forecast to increase in the future. The shortfall in transmission capability is forecast to be about (please refer to the figure reproduced below):

1. 0 MW in early 2007 (Existing System, only six units in-service at Bruce NGS)

2. 500 MW in 2008 (Committed Wind goes in-service)

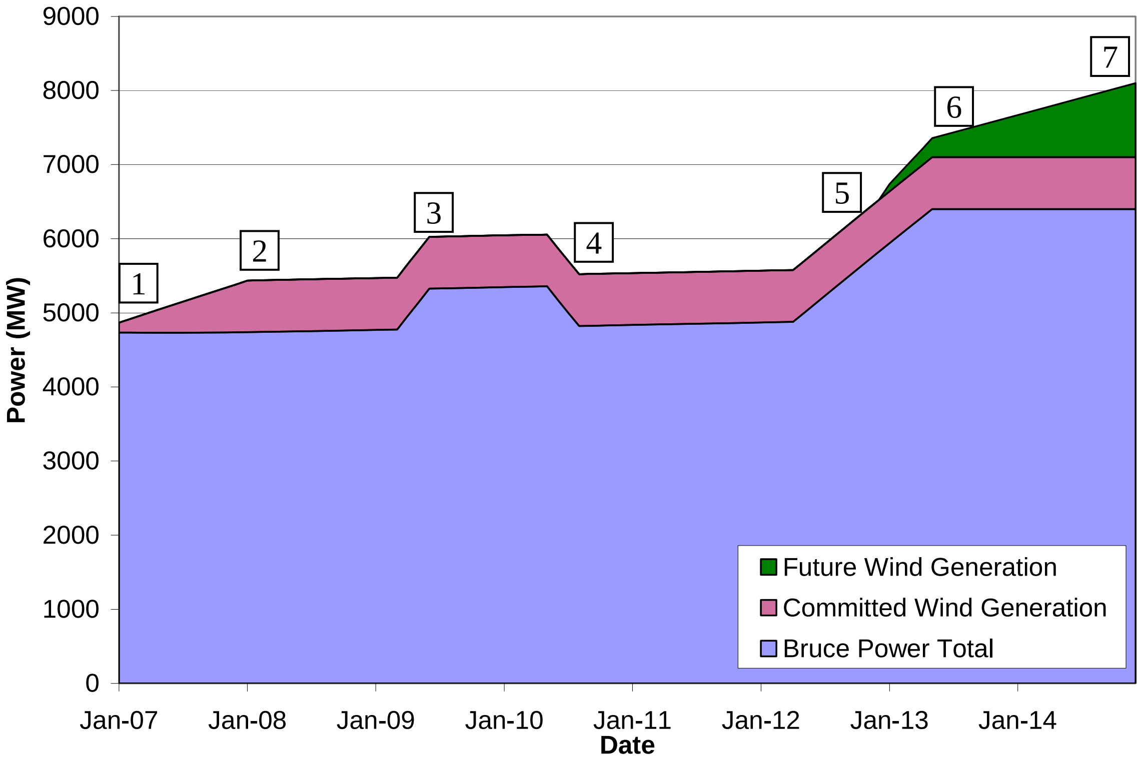
3. 1,000 MW in 2009-2010 (Bruce A units 1 and 2 return from refurbishment before Bruce A units 3 and 4 are removed from service for refurbishment)

4. 500 MW in 2011 (Both units 3 and 4 are being refurbishment)

5. 1,500 MW in 2012 (Bruce units start returning from refurbishment)

6. 2,600 MW in 2013 (All eight Bruce units are in-service, planned wind starts coming in-service)

7. 3,100 MW in 2014 (All eight Bruce units are in-service; most of the planned wind is in-service)



The capability of the existing Bruce transmission system is about 5,000 MW. While the proposed near-term measures will increase the capability to 5,400 MW, this is still far short of the capability required in 2009 of 6,000 MW total. Thus, the need for long-term reinforcement of the Bruce transmission system exists in 2009. Until this reinforcement (the Project) is in place, interim stop-gap measures must be used, such as generation rejection and continuation of the OPA moratorium under the Standard Offer Program with regard to granting power purchase contracts for generation developments in the Bruce Area.

Exhibit No. 7

Pollution Probe INTERROGATORY # 3 List 1

Interrogatory

Issue Number: 1.0
Issue: Project Need and Justification

Ref. B/Tab 1/Sch 1 and B/Tab 4/Sch 4

For each year from 2012 to 2036 inclusive, please provide the OPA's estimates of the total generation (MWh) for the Bruce Area. Please also break-out these estimates by the following generation types:

a) existing Bruce A nuclear reactors;

b) existing Bruce B nuclear reactors;

c) re-built Bruce B nuclear reactors;

d) new Bruce nuclear reactors;

e) existing wind generation;

f) committed wind generation;

g) uncommitted wind generation; and

h) other.

Response

The Bruce Area has been studied by the OPA only to 2030. Information for the period 2012 to 2030 is shown below. Information to 2036, as requested in the Interrogatory, is not available.

The following assumptions have been made in order to respond to this interrogatory:

1. The nuclear capacity at Bruce will be the equivalent to the 4 Bruce A and 4 Bruce B units in the long term.

2. 15 MW of existing wind generation in the Bruce Area.

3. 685 MW of committed wind generation in the Bruce Area.

4. There will be 1000 MW of future wind generation in the Bruce Area.

5. An Effective Forced Outage Rate of 8% was assumed for the Bruce nuclear units.

6. Each unit at Bruce would require 45 days in every two years for planned maintenance outages.

7. The Bruce NGS B units will be refurbished starting in 2018.

8. Each unit will take 2.5 years to refurbish.

9. Wind in the Bruce Area has an average energy that is equivalent to approximately 29% of the installed capacity running for the entire year.

The results are presented below in table format for each of the requested breakdowns:

Energy (MWh)

Year	Bruce A	Bruce B	Bruce B Refurb	Existing Wind	Committed Wind	Future Wind	Total
2012	15124800	25586624	0	37681	1720767	0	42469872
2013	22214550	25712160	0	37681	1720767	791302	50476459
2014	22687200	25712160	0	37681	1720767	1971974	52129782
2015	22687200	25712160	0	37681	1720767	2512068	52669876
2016	22687200	25712160	0	37681	1720767	2512068	52669876
2017	22687200	25712160	0	37681	1720767	2512068	52669876
2018	22687200	19284120	0	37681	1720767	2512068	46241836
2019	22687200	12856080	0	37681	1720767	2512068	39813796
2020	22687200	9642060	3214020	37681	1720767	2512068	39813796
2021	22687200	3214020	9642060	37681	1720767	2512068	39813796
2022	22687200	0	12856080	37681	1720767	2512068	39813796
2023	22687200	0	19284120	37681	1720767	2512068	46241836
2024	22687200	0	25712160	37681	1720767	2512068	52669876
2025	22687200	0	25712160	37681	1720767	2512068	52669876
2026	22687200	0	25712160	37681	1720767	2512068	52669876
2027	22687200	0	25712160	37681	1720767	2512068	52669876
2028	22687200	0	25712160	37681	1720767	2512068	52669876
2029	22687200	0	25712160	37681	1720767	2512068	52669876
2030	22687200	0	25712160	37681	1720767	2512068	52669876

Pollution Probe INTERROGATORY # 4 List 1

Interrogatory

Issue Number: 1.0

Issue: Project Need and Justification

Ref. B/Tab 1/Sch 1 and B/Tab 4/Sch 4

For each year from 2012 to 2036 inclusive, please provide the OPA's estimates of the total effective generation capacity (MW) in the Bruce Area at the time of Ontario's province-wide system peak. Please also break-out these estimates by the following generation types:

a) existing Bruce A nuclear reactors;

b) existing Bruce B nuclear reactors;

c) re-built Bruce B nuclear reactors;

d) new Bruce nuclear reactors;

e) existing wind generation;

f) committed wind generation;

g) uncommitted wind generation; and

h) other.

Response

Please refer to the response to Pollution Probe's Question 3 for a list of assumptions employed by the OPA in developing a response to this interrogatory.

For the purpose of responding to this interrogatory, "Effective Generation Capacity" at the time of system peak is being defined as 20% of installed capacity for wind generation and as (100%-Effective Forced Outage Rate) of the installed capacity for nuclear generation.

The results are presented below in table format for each of the requested breakdowns:

Effective Capacity (MW)

Year	Bruce A	Bruce B	Bruce B Refurb	Existing Wind	Committed Wind	Future Wind	Total
2012	2070	3113	0	3	137	0	5323
2013	2760	3128	0	3	137	63	6091
2014	2760	3128	0	3	137	157	6185
2015	2760	3128	0	3	137	200	6228
2016	2760	3128	0	3	137	200	6228
2017	2760	3128	0	3	137	200	6228
2018	2760	2346	0	3	137	200	5446
2019	2760	1564	0	3	137	200	4664
2020	2760	782	782	3	137	200	4664
2021	2760	0	1564	3	137	200	4664
2022	2760	0	1564	3	137	200	4664
2023	2760	0	2346	3	137	200	5446
2024	2760	0	3128	3	137	200	6228
2025	2760	0	3128	3	137	200	6228
2026	2760	0	3128	3	137	200	6228
2027	2760	0	3128	3	137	200	6228
2028	2760	0	3128	3	137	200	6228
2029	2760	0	3128	3	137	200	6228
2030	2760	0	3128	3	137	200	6228

Exhibit No. 8

Pollution Probe INTERROGATORY #16 List 2

Interrogatory

Issue Number: 1.0
Issue: Project Need and Justification

Ref Ontario Energy Board Act, 1998, section 92; Technical Conference Presentation by Hydro One, Panel 1, Existing Facilities and Grid Operation, Need, Alternatives and Evaluation, and Near-term & Interim Measures, October 15/16, 2007 Section 6. “Near Term and Interim Measure Improvements”

Please provide the following information:

a) What are the total costs associated with the implementation of each of the transmission system improvements below?
b) In what year or years are those costs incurred?
c) What is the increased transmission system capability away from the Bruce area for each transmission system improvement?
d) What is the cumulative total transmission transfer capability away from the Bruce area after each transmission system improvement is completed? And
e) In what year does each incremental transmission capability increase occur?

The transmission system improvements referenced above include:

a) Near term improvements including the Hanover to Orangeville line and dynamic and static reactive resources at various southwestern Ontario substations;
b) Medium-term improvement or “interim” measure of expansion of Bruce special protection system and employment of generation rejection system;
c) Medium-term improvement of implementation and employment of series compensation on the southwestern Ontario 500 kV system;
d) Any other transmission system improvements not covered by these stated near-term and medium term measures; and
e) The proposed double-circuit 500 kV lines from Bruce to Milton.

Response

Parts a through e) of this Interrogatory are addressed in the table shown on the following page. A discussion of the table’s contents and their calculation is then provided.

1 **Table 1 – Summary of Costs, Capabilities and Suitability of the Bruce Transmission System Improvements**

	A	B	C	D	E	F	G	H	I
Scenario	**Incremental Cost of Upgrade ($M)**	**Total Cost of Upgrade ($M)**	**Incremental Cost Incurred in (year)**	**Increase in Transfer Capability (MW)**	**Total Transfer Capability (MW)**	**Shortfall from Identified Need (MW)**	**Increased Capability Available in (year)**	**Suitable for Long-Term Use?**	**Meets the Need?**
Existing System	-	-	-	-	5000	**(3100)**	-	Yes	No
a) Near Term Measures (NTM) (includes upgrade of Hanover to Orangeville 230 kV line; and shunt capacitors and static var compensators to accommodate additional flow out of the Bruce Area and to replace the reactive power lost due to the phase out of the Nanticoke units)	+216	216	2007-2010	+385	5385	**(2715)**	2009 - 2010	Yes	No
b) NTM + Expansion of Bruce Special Protection System (BSPS) for use under normal system conditions	+7	223	2008-2010	+941	6326	**(1774)**	2010	No	No
c) NTM + Series Capacitors + BSPS for use during outage conditions	+97	320	2008-2011	+941 [above a]	6326	**(1774)**	2012	Yes	No
d) NTM + Series Capacitors + BSPS for use under normal system conditions	+0	320	2008-2011	+750	7076	**(1024)**	2012	No	No
e) NTM + Proposed Bruce x Milton Line + BSPS for use during outage conditions	+645 [above (b)]	868 [216+7+645]	2007-2011	+1084 [above (d)]	8160	**+60**	2012	Yes	Yes

Discussion of Table Results

This interrogatory requested analysis of the incremental transfer capability of five scenarios involving different levels of system improvements. Table 1 summarizes the information requested. The following notes provide explanations of the table's contents:

- Two of these scenarios contemplate the use of Generation Rejection under normal system conditions (as compared with the use of GR under outage conditions) and therefore are not suitable for long-term use: see the response to OEB Staff Interrogatory 3.2. Column H of Table 1 above indicates whether a particular scenario is suitable for long-term use.

- The costs associated with each scenario are shown in Table 1 columns A and B. The total and incremental costs have been included. Please note that the Near Term Measures are common to all scenarios as they are required to implement any of the long term solutions (i.e., Series Capacitors or the proposed Bruce to Milton Line).

- The years in which the incremental system upgrade cost is incurred is shown in Table 1 column C. The costs of each scenario have been calculated incremental to the scenario found above it, unless noted otherwise.

- The incremental transfer capability away from the Bruce Area is shown in Table 1 column D. Each system's capability has been calculated incremental to the one above it in the table, unless noted otherwise.

- The total transfer capability is shown in Table 1 column E and the shortfall in transfer capability relative to the need is shown in column F.

- The year in which the transmission capability of each scenario becomes available is shown in Table 1 column G.

The information in Table 1 demonstrates that the only case that can meet the identified transfer capability need of at least 8100 MW is the proposed Bruce to Milton line with the near-term measures and use of GR during outage conditions (shown by the only "Yes" in column I of the Table 1). The near-term measures add about 385 MW in capability and the Bruce to Milton line adds a further 2775 MW, in combination with the use of GR during outage conditions.

Series compensation can increase the transfer capability by about 941 MW. The resulting transfer capability of 6326 MW is far short, by about 1800 MW, of the level required to meet the need identified. Furthermore, even when used over the long-term under normal system conditions, a use which is not consistent with the NPCC and IESO reliability standards, further augmentation of the series compensated system with generation rejection under normal conditions provides a capability of only about 7076 MW, or about 1000 MW short of the capability required.

Options such as employing series capacitors to stretch the existing system to its fullest, which are appropriate when smaller increases are required, or those such as generation rejection, which are intended to provide relief for the transmission under adverse conditions, are not substitutes to a robust, appropriately designed, long-term reinforcement option such as the Bruce to Milton line when significant increase in transmission capability is required, as is the case in this application. Partial or inappropriate G/R solutions will not address the need identified and will expose the system to undesirable levels of increasing risk and complexity.

Exhibit No. 9

Saugeen Ojibway First Nations INTERROGATORY #2 List 1

Interrogatory

Ref. Exh. *B/T 6/S 6/*Appendices 1, 2, 5 [and *10/15/07* Tech. Conference at 22:4 - 24:2]
Issue Number: 1.1
1.1 Issue: Has the need for the proposed project been established?

Reguest

Please state the transfer capability away from the Bruce Complex by use of both (i) NPCC Operating Procedures (loss of one circuit on a double circuit tower) and (ii) planning criteria (loss of both circuits on a double circuit tower) for each of the following conditions:

a. The existing transmission system.
b. The existing transmission system with near-term upgrades.
c. The existing transmission system with interim term upgrades.
d. The existing transmission system with the existing generation rejection scheme, near-term upgrades and series capacitors.
e. The existing transmission system with an ENHANCED generation rejection scheme (of up to two Bruce Units), near-term upgrades and series capacitors.

Response

The NPCC Operating Criteria and the planning criteria include the same contingencies. Therefore, IESO has responded to this Interrogatory by considering the most limiting contingency, namely the loss of two circuits on a double circuit tower.

The *Transmission Design Criteria* defined in Section 5 of *NPCC Document A2: Basic Criteria for Design and Operation of Interconnected Power Systems*, require that both stability and acceptable voltages be maintained during and following the most severe of the contingencies listed below:

(a) A permanent three-phase fault on any generator, transmission circuit, transformer or bus section with **normal fault clearing**.

(b) Simultaneous permanent phase-to-ground faults on different phases of each of two adjacent transmission circuits on a multiple circuit tower, with **normal fault clearing**.

(c) A permanent phase-to-ground fault on any transmission circuit, transformer, or bus section with **delayed fault clearing**.

(d) Loss of any **element** without a fault.

(e) A permanent phase-to-ground fault on a circuit breaker with **normal fault clearing**.

(f) Simultaneous permanent loss of both poles of a direct current bipolar facility without an ac fault

(g) Failure of a circuit breaker to operate when initiated by an SPS following: loss of any **element** without a fault; or a permanent phase-to-ground fault, with **normal fault clearing**, on any transmission circuit, transformer or bus section.

The transfer capability from the Bruce area that is quoted for each of the scenarios listed therefore corresponds to the double-circuit contingency condition involving circuits B560V & B561M.

(a) The existing transmission system.

- *Transfer capability*: Approximately 5000MW

(b) The existing transmission system with near-term upgrades.

- *Transfer capability*: Approximately 5400MW

The increase in the transfer capability resulting from the ongoing uprating of circuits B4V & B5V between Hanover TS and Orangeville TS will allow the wind-turbine projects connected to these circuits to be incorporated.

(c) The existing transmission system with interim upgrades.

- *Transfer capability*: Approximately 6325MW

Once the interim measures have been completed and assuming that post-contingency generation rejection is initiated to reject one unit at the Bruce Complex together with the 400MW of wind-turbine capacity associated with circuits B4V & B5V, then the output from a total of seven Bruce units together with the 675MW (excluding the 25MW incorporated into the distribution system in the Bruce area) of committed wind-turbine capacity could be accommodated.

Please refer to the response to Saugeen Interrogatory No. 9 which explains why generation rejection at the Bruce Complex would be restricted to only a single unit.

(d) The existing transmission system with the existing generation rejection scheme, near-term upgrades and series capacitors.

- *Transfer capability*: Approximately 6325MW - with no G/R initiated.

- *Transfer capability*: Approximately 7075MW - with the rejection of one Bruce unit initiated post-contingency

Without generation rejection, the installation of series capacitors would allow the output from seven units at the Bruce Complex together with that from the 675MW of committed wind-turbine projects to be accommodated.

With a single unit at the Bruce complex rejected post-contingency, the series capacitors would allow the combined output from all eight units at the Bruce Complex together with the committed wind-turbine projects to be accommodated.

(e) The existing transmission system with an ENHANCED generation rejection scheme (of up to two Bruce Units), near-term upgrades and series capacitors.

- *Transfer capability*: Approximately 6325MW - with no G/R initiated.

- *Transfer capability*: Approximately 7075MW - with the rejection of one Bruce unit initiated post-contingency

The enhancements to the generation rejection scheme are intended to expand the number of contingency conditions to which the scheme can respond as well as increasing the range of actions that can be initiated in response to these contingencies.

It will not permit any increase in the number of units at the Bruce Complex that could be rejected for the most severe double-circuit contingency condition involving the Bruce-to-Milton line while all transmission elements in-service.

The transfer capability therefore remains the same as that quoted for condition e.

Please see the response to Board Staff Interrogatories 3.2 and 3.4 for further information regarding the use of series capacitors and generation rejection as stop-gap measures to meet the need while the long-term solution is under development.

Exhibit No. 10

Saugeen Ojibway First Nations INTERROGATORY #10 List 1

Interrogatory

Ref. Exh. *B/T 6/S* 2, Exh. *BIT 6/S* 5/Appendix 5, other studies performed by the IESO
Issue Number: 3.3

3.3 Issue: If these proposed near term and interim measures could be utilized for a longer period than proposed, could they (or some combination of similar measures) be considered an alternative to the double circuit 500 kV transmission line for which Hydro One has applied?

Request

Please indicate whether IESO (or any other party) has modeled the impact upon the effective transfer capability out of Bruce using a OR of up to two Bruce Units in addition to series compensation. If such studies have been conducted, please provide the results of such studies and the load flow input data in computer readable form. If no such studies were conducted, please indicate the reason for not conducting such studies.

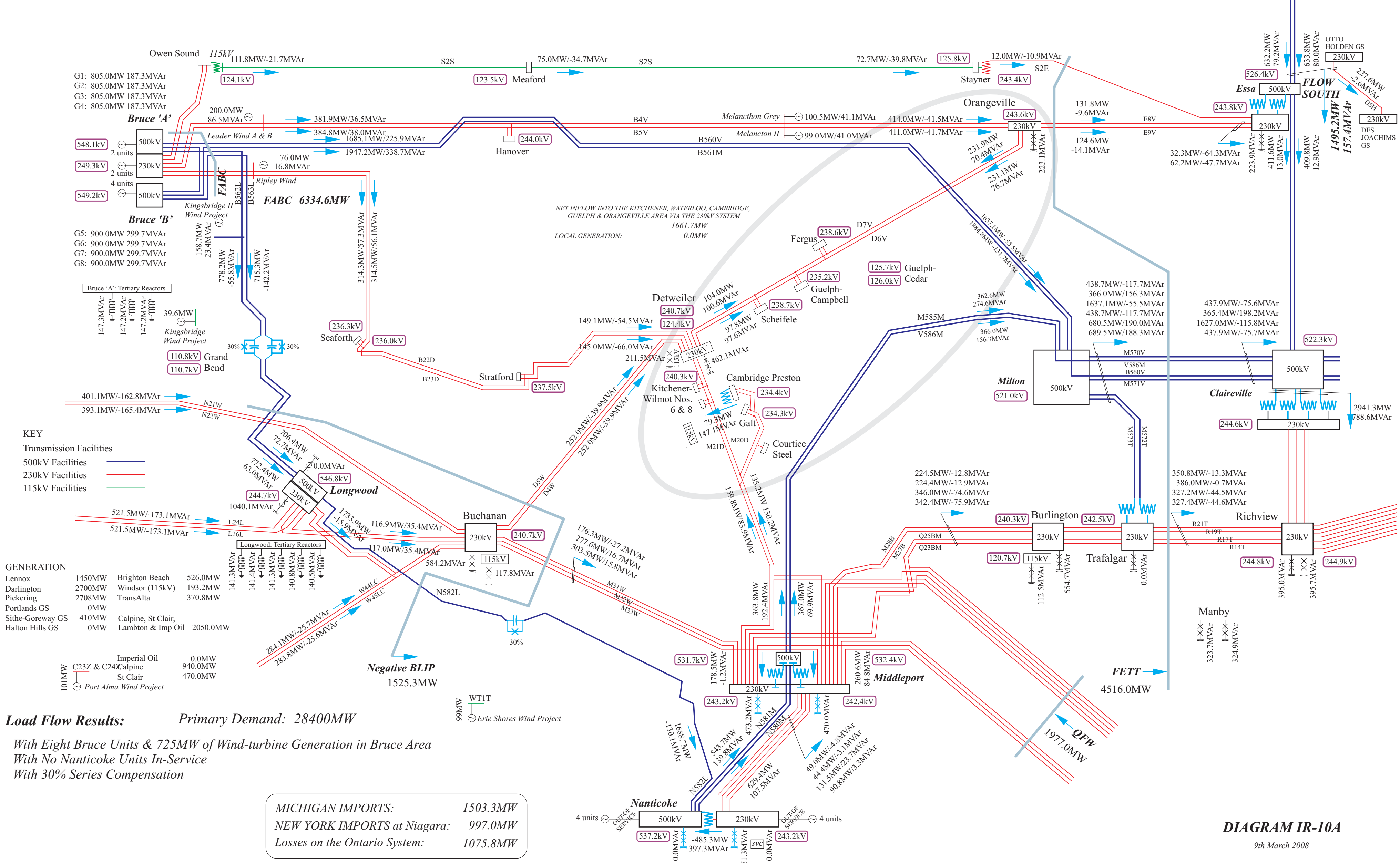
Response

In the IESO's SIA Report Entitled "Proposed Installation of Series Capacitors in 500 kV Circuits Between the Bruce Complex and Nanticoke GS" dated April 11 2006 (Ref: IESO_REP_0299 and filed in this proceeding as part of the response to Pappas Interrogatory No. 2 demonstrated that the existing system would be capable of accommodating seven units at the Bruce Complex together with the 675MW of committed wind-turbine projects in the Bruce area without deploying generation rejection if series capacitors, together with the interim measures were implemented.

The IESO has also determined that maximum amount of generation rejection that is permissible when post contingency increase in losses are taken into account is 1 Bruce unit and up to 400 MW of wind generation. With this restriction there would be no capacity to accommodate any incremental generation beyond an eighth Bruce unit.

The results of the load flow study for the pre- & post-contingency conditions with series capacitors installed and with a single unit at the Bruce Complex rejected are shown in the attached Diagrams A & B, respectively.

Filed: March 11, 2008
EB-2007-0050
Exhibit C
Tab 5
Schedule 10
Diagram A
Page 1 of 1



Filed: March 11, 2008
EB-2007-0050
Exhibit C
Tab 5
Schedule 10
Diagram B
Page 1 of 1

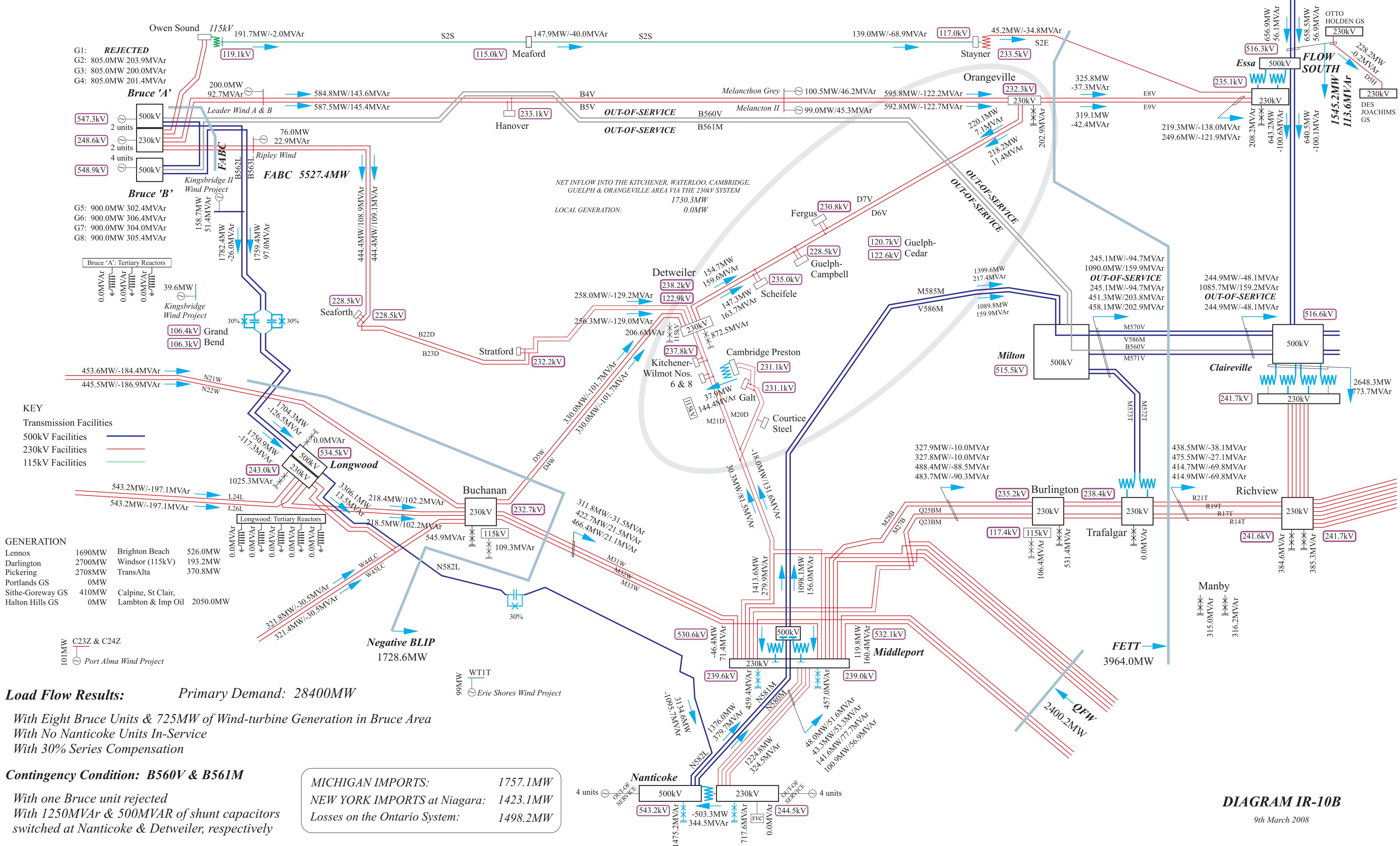


Exhibit No. 11

Pappas INTERROGATORY #1 List 1

Interrogatory

Issues:
1.1. Has the need for the proposed project been established?

2.1 Have all reasonable alternatives to the project been identified and considered?

2.2 Has an appropriate evaluation methodology been applied to all the alternatives considered?

2.4a Have appropriate evaluation criteria and criteria weightings been utilized in the evaluation process for the alternatives and the proposed project and what additional criteria/weightings could be considered?

3.1 Are the proposed near term and interim measures as outlined in the application appropriate?

Ref

1. APPENDIX A to Procedural Order No. 5.In The Matter of Leave to Construct Application by Hydro One Networks.EB-2007-0050.Dated February 25, 2008

2. Direction of Board from Issues Day and Schedule Hearing, February.21, 2008.

Preamble:

The following documents are, in my estimation, entirely relevant and necessary for the understanding of the Board, and the Interveners, of the Application, the Applicant's preferred option and how that option was deemed to be superior to the alternatives. As was determined at the Issues Day and Schedule Revision hearing [Feb.21, 2008], it is in the best interests of all parties, and the Application process, that these be made immediately available to the Interveners and the Board for review and consideration. Also, at this time it was, apparently, determined that two of these documents were definitely produced with public availability understood, and that there was no matter of confidentiality for any of the first three documents requested. The Applicant voiced no objection to any of this at the hearing [Feb. 21, 2008]. I must state, here, that I will view non-compliance regarding these initial five interrogatories as a matter of Motion, and will request a Motions day on this basis. As I understand, the following requests were, however, to be framed as Interrogatory. So that there will be no chance of refusal based on my earlier written request not being precisely framed in Interrogatory format I have revised them, as follows.

Request:

Will, the Applicant and its Proponents [OPA, IESO] provide the Interveners, and the Board, with the relevant documents, studies, consultations or reports, listed below?

1. IESO_REP_0245v2.0
   10-YEAR OUTLOOK:
   An Assessment of the Adequacy of Generation and Transmission Facilities to Meet Future Electricity Needs in Ontario from January 2006 to December 2015
   [release date: August 15, 2005]

2. IESO_REP_0299
   CONNECTION ASSESSMENT & APPROVAL PROCESS SYSTEM IMPACT ASSESSMENT REPORT
   For the Proposed Installation of Series Capacitors in the 500kV Circuits between the Bruce Complex & Nanticoke GS
   Applicant: Hydro One Networks Inc.
   CAA ID No. 2005 200
   Transmission Assessments & Performance Department
   FINAL Version
   Date: 11th April 2006

3. From: Pg. 38 of the SIA REPORT: INSTALLATION OF 500kV SERIES COMPENSATION.[#2, above]
   The study, cited under: 16.2 Recommendations.
   •The ABB Study that was commissioned by Hydro One.

<u>Response</u>

The requested studies are included as Attachments 1, 2 and 3-1 to 3-3 on the CD being provided. Hard copies of the Attachments 1 and 2 are also included.

Attachment 3 (the ABB study and companion pieces) contains the following reports:

- 3-1 – Main Report (labelled "Draft Report")

- 3-2 – Appendices

- 3-3 – SSR Mitigation Final Report

Hydro One Networks Inc.

Southwestern Ontario Transmission 500kV Series Compensation Technical Studies Power Flow and Dynamics Report

DRAFT REPORT

November 30, 2005

PREPARED FOR:

HYDRO-ONE
483 Bay Street
Toronto, Ontario
M5G 2P5

PREPARED BY:

ABB Inc.
ABB Consulting
940 Main Campus Drive, Suite 300
Raleigh, North Carolina 27606-5202
Telephone: (919) 856-2469
Fax: (919) 807-5060

The system was found to be stable with acceptable transient voltage recovery characteristic for all the 18 simulation cases. For slower clearing (outside the minimum criteria requirement) of simultaneous L-G fault (≈ 10 cycles) wind farm generator tripping was noted due to the under-voltage protection settings used in these simulations. This indicates that the possibility of changes to such relay settings need to be reviewed.

As a sensitivity case, 110% power transfer from Bruce complex was also tested and found to be stable. This confirms that the additional reactive support from steady state voltage stability testing need not be fast acting (i.e. dynamic).

Another sensitivity testing condition involved fault at two points (about 30% from Longwood and Nanticoke) of zero net series impedance or highest fault level. The system was found to be stable in all the four cases.

A third sensitivity case was run to take a cursory look at damping and this case shows that further examination of damping requirements coupled with the additional reactive support may be necessary.

In conclusion, both the power flow dynamic simulation results confirm that the proposed series compensation of the 500kV lines is feasible and will meet the power transfer requirements. The simulation results show that further optimization (both technical and economic) of both the series and shunt compensation levels is desirable. Such optimized levels compensation should provide a better and more economic solution for the upgrade of the main 500kV transmission loop of Bruce-Longwood-Nanticoke-Claireville-Milton.

Exhibit No. 12

Independent Electricity
System Operator
Station A, Box 4474
Toronto, Ontario M5W 4E5
t 905 855 6100
www.ieso.ca

IESO_REP_0299

CONNECTION ASSESSMENT & APPROVAL PROCESS

SYSTEM IMPACT ASSESSMENT REPORT

For the Proposed Installation of Series Capacitors in the 500kV Circuits between the Bruce Complex & Nanticoke GS

Applicant: Hydro One Networks Inc.

CAA ID No. 2005-200

Transmission Assessments & Performance Department

FINAL Version

Date: 11th April 2006

System Impact Assessment Report

For the Installation of Series Capacitors in the 500kV Circuits between the Bruce Complex & Nanticoke SS

Acknowledgement

The IESO wishes to acknowledge the assistance of Hydro One in completing this assessment.

Disclaimers

IESO

This report has been prepared solely for the purpose of assessing whether the connection applicant's proposed connection with the IESO-controlled grid would have an adverse impact on the reliability of the integrated power system and whether the IESO should issue a notice of approval or disapproval of the proposed connection under Chapter 4, section 6 of the Market Rules.

Approval of the proposed connection is based on information provided to the IESO by the Hydro One Networks Inc. at the time the assessment was carried out. The IESO assumes no responsibility for the accuracy or completeness of such information, including the results of studies carried out by the transmitter at the request of the IESO. Furthermore, the connection approval is subject to further consideration due to changes to this information, or to additional information that may become available after the approval has been granted. Approval of the proposed connection means that there are no significant reliability issues or concerns that would prevent connection of the proposed facility to the IESO-controlled grid. However, connection approval does not ensure that a project will meet all connection requirements. In addition, further issues or concerns may be identified by the transmitter during the detailed design phase that may require changes to equipment characteristics and/or configuration to ensure compliance with physical or equipment limitations, or with the Transmission System Code, before connection can be made.

This report has not been prepared for any other purpose and should not be used or relied upon by any person for another purpose. This report has been prepared solely for use by the connection applicant and the IESO in accordance with Chapter 4, section 6 of the Market Rules. The IESO assumes no responsibility to any third party for any use, which it makes of this report. Any liability which the IESO may have to the connection applicant in respect of this report is governed by Chapter 1, section 13 of the Market Rules. In the event that the IESO provides a draft of this report to the connection applicant, you must be aware that the IESO may revise drafts of this report at any time in its sole discretion without notice to you. Although the IESO will use its best efforts to advise you of any such changes, it is the responsibility of the connection applicant to ensure that the most recent version of this report is being used.

Hydro One

Special Notes and Limitations of Study Results

The results reported in this system impact assessment are based on the information available to Hydro One, at the time of the study, suitable for a system impact assessment of a new transmission facility.

HYDRO ONE NETWORKS Inc.

SYSTEM IMPACT ASSESSMENT REPORT

For the Installation of Series Compensation in the 500kV Circuits Associated with the Bruce Complex

EXECUTIVE SUMMARY

1. General

Agreement has been reached between the Government of Ontario and Bruce Power Inc. for the return to service in 2009 of Units 1 & 2 at the Bruce A nuclear generating facility. In addition, contracts have been awarded under the Government of Ontario's Renewables I & II RFPs for the incorporation of wind-turbine generation capacity totalling 1370MW. Of this, approximately 725MW is to be incorporated into the system directly associated with the Bruce Complex, with a further 200MW to be incorporated into that part of the system that will have a direct effect on the transfers across the Negative-BLIP (Buchanan-Longwood Input) Interface.

To accommodate the additional output from Bruce Units 1 & 2 and from the wind-turbine generation facilities, Hydro One submitted a proposal for the installation of series capacitors in the 500kV transmission facilities associated with the Bruce Complex.

The primary objectives that the installation of the series capacitors were intended to meet were:

- To increase the post-contingency transient stability limit of the existing transmission facilities so as to avoid the need for rejecting any generating capacity in response to a first contingency.

- To encourage a higher proportion of the output from the Bruce Complex to flow through the remaining 500kV transmission facilities between the Bruce Complex and Nanticoke SS following the coincident loss of the 500kV circuits from the Bruce Complex to Milton TS and to Claireville TS.

  This was also intended to reduce the post-contingency transfers on the 230kV circuits between the Bruce Complex and Orangeville TS.

- To reduce the reactive power losses and to improve the pre- and post-contingency voltage profiles.

2. Generation Scenarios

Although Bruce Units 1 & 2 are scheduled to be returned to service during 2009, other units at the Bruce Complex are scheduled to be removed from service for maintenance. Consequently during the period between April-2009 and the end-2011, a maximum of only seven Bruce units are expected to be operational.

Beyond December-2011, there are expected to be extended periods when all eight Bruce units will be in-service.

The assessment therefore considered these two scenarios.

In addition it was assumed that all of the units at Nanticoke GS would have ceased operation as generating units prior to the first Bruce unit being returned to service in April-2009.

3. Preliminary Review of the Proposal

The IESO identified the following additional facilities that would need to be installed to ensure acceptable post-contingency voltages. These have been shown on Diagram Exec. 1 and the arrangement shown was adopted as the reference proposal for this assessment:

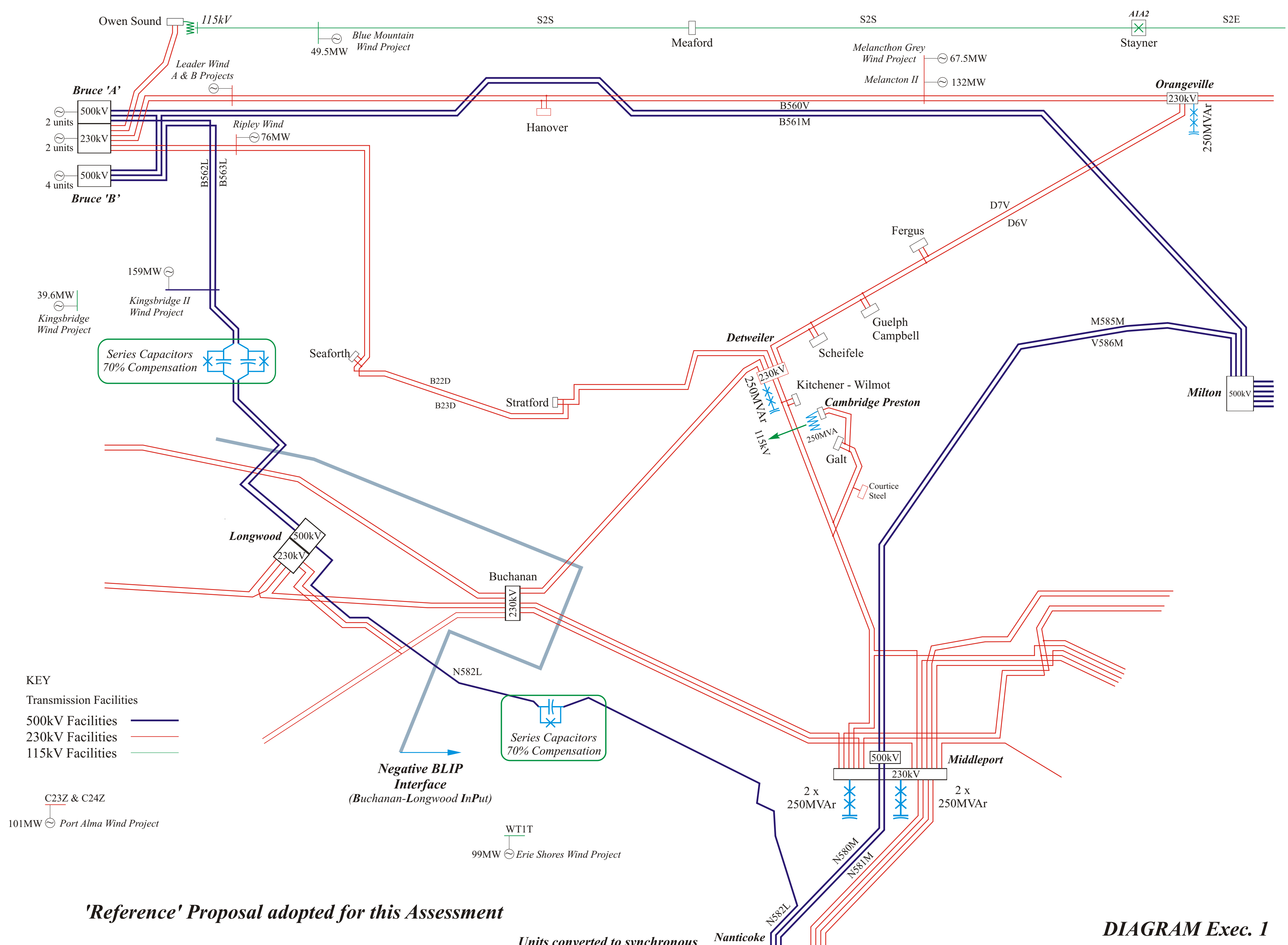


DIAGRAM Exec. 1

26th March 2006

- A 250MVAr 230kV shunt capacitor bank at both Detweiler TS and Orangeville TS.
- Two 250MVAr 230kV shunt capacitor banks on each half of the 230kV busbar at Middleport TS.
- Two 250MVAr 230kV shunt capacitor banks on the 230kV busbar at Nanticoke SS.
- Up to four of the existing generating units at Nanticoke GS converted to synchronous condenser operation.
- A 250MVA 230/115kV auto-transformer at Cambridge-Preston TS to interconnect the 230kV circuits M20D/M21D to the 115kV circuits D7G/D9G.

4. *Transient Stability Analysis*

The studies that were performed for a line-line-ground fault involving the 500kV circuits B560V & B561M showed that transient stability, with a 10% margin, could be maintained for the following conditions:

Generation Scenario	*Transmission Scenario*	*Series Compensation Required*	
		500kV Bruce x Longwood	500kV Longwood x Nanticoke
Seven Bruce Units & 925MW of Wind-turbine Generation	Existing Transmission Facilities	20%	20%
Eight Bruce Units & 925MW of Wind-turbine Generation	With a New 500kV Single-circuit Line: Longwood x Middleport	20%	10% & 10% on the new line
	With a new 500kV Double-Circuit Line: Bruce x Essa	No Compensation Required	
	With a new 500kV Double-Circuit Line: Bruce x Milton		

5. *Load Flow Analysis with Seven Bruce Units*

Load Flow studies were performed for the condition with maximum transfers into Ontario across the Ontario-Michigan and Ontario-New York Interfaces of 1500MW and 1400MW, respectively.

In addition, with the four units at Lambton GS retired and with the new Calpine - Greenfield Energy Centre and the Invenergy - St Clair Projects assumed to be in-service in the Sarnia area, a system primary demand of 25000MW was found to result in transfers across the Negative-BLIP Interface that were close to the operating limit of 1500MW.

The Load Flow studies showed that with Negative-BLIP transfers of approximately 1500MW and with the 500kV Bruce-to-Longwood and the Longwood-to-Nanticoke circuits compensated to levels **above 50%**, the post-contingency flows on the 500kV Longwood-to-Nanticoke circuit were well in excess of its long-term emergency rating of 3660A at an operating temperature of 127^{o}C.

In addition, regardless of the level of compensation employed, the post-contingency flow on the 115kV circuit S2S between Owen Sound TS and Stayner TS was found to exceed its rating. While the situation was aggravated by the presence of the 50MW Blue Mountain Wind Project, post-contingency rejection of this project was not sufficient to maintain the flows within the circuit's rating. However, cross-tripping of the A1A2 in-line breaker at Stayner TS was found to be effective.

Hydro One subsequently indicated that the 500kV circuit between Longwood TS and Nanticoke SS could be uprated for operation at a temperature of 150^{o}C to provide an enhanced rating of *4110A*. However, flows would only be permitted at this level for a maximum of three hours per year.

With the Bruce-to-Longwood and the Longwood-to-Nanticoke circuits compensated **to 50%**, the post-contingency flow of 4043A on the latter circuit would be within its enhanced rating of 4110A. However, the post-contingency flows of 1460A on the section of circuits B4V & B5V between the Melancthon Wind Projects and Orangeville TS would exceed the 4km/hr wind-speed rating of 1180A but would be within the 15km/hr wind-speed rating of 1590A. Since the wind projects require wind-speeds in excess of 8m/sec (~ 30km/hr) to produce approximately half their peak output, using a wind-speed of 15km/hr for calculating ratings for transmission facilities within 50km of a wind-turbine project has been adopted by the IESO for its assessments.

Reducing the level of compensation on the 500kV circuits **to 40%** would reduce the post-contingency flow on circuit N582L between Longwood TS and Nanticoke TS (to 3849A) , but would increase the post-contingency flow on circuits B4V & B5V between the Melancthon Wind Projects and Orangeville TS to 1557A. Although the flow on circuits B4V & B5V would remain within their 15km/hr wind-speed rating, the flow on circuit N582L would still exceed its long-term emergency rating and it would therefore still be necessary to increase its maximum operating temperature above its present value of 127^{o}C.

A further reduction in the level of compensation on the 500kV circuits **to 30%** would achieve a post-contingency flow of 3669A on circuit N582L which would be sufficiently close to the present long-term emergency rating for this circuit of 3660A that uprating could be avoided. However, the post-contingency flows on circuits B4V & B5V would increase to 1649A which would exceed the 15km/hr long-term emergency rating of 1590A for these circuits.

Increasing the sag temperature of this line from its present value of 104^{o}C to 127^{o}C would increase its 4km/hr wind-speed rating to 1400A and its 15km/hr wind-speed rating to 1830A.

Since the level of compensation would still exceed the minimum required to maintain post-contingency transient stability without having to employ generation rejection, the IESO has therefore concluded that either of the following options would be acceptable:

<table>
<tr><td colspan="3">Options for Installing Series Compensation on the 500kV Circuits between the Bruce Complex & Nanticoke SS</td></tr>
<tr><td rowspan="2">Level of Series Compensation to be installed on the following 500kV Circuits:
• B562L & B563L Bruce x Longwood TS
• N582L Longwood TS x Nanticoke SS</td><td colspan="2">Associated Remedial Requirements</td></tr>
<tr><td>500kV Circuit N582L: Longwood TS x Nanticoke SS</td><td>230kV Circuits B4V & B5V: Section from Hanover TS to Orangeville TS</td></tr>
<tr><td>1. 50% or 40%</td><td>Increase the sag temperature of the line to 150^{o}C</td><td>No Action Required</td></tr>
<tr><td>2 30%</td><td>No Action Required</td><td>Increase the sag temperature of the line to 127^{o}C</td></tr>
</table>

6. Re-Preparation of the System with Seven Bruce Units

In the event of a sustained outage involving the two 500kV circuits B560V & B561M, a subsequent contingency involving the 500kV circuit N582L would be the most onerous for the system. The assessment has shown that for the condition with the 500kV circuits compensated to 50%, the following actions would need to be taken to prepare the system for a subsequent contingency involving circuit N582L during the 30-minute Re-preparation Period:

- Reduce the transfers across the Ontario-New York Interface to their Pre-contingency levels - this would represent a net reduction in imports of approximately 190MW
- Remove the wind-turbine projects that are connected to circuits B4V & B5V from service - this would result in a resource deficiency of approximately 400MW

- Reduce the transfers across the Ontario-Michigan Interface from 1310MW to 775MW - this would represent a net reduction in imports of approximately 535MW

Following these actions the system transmission losses would be approximately 1020MW, representing an increase of approximately 220MW over the pre-contingency losses.

The combined effect of these actions would therefore be a resource deficiency of approximately 1345MW.

Since the IESO is required to maintain a minimum 30-minute operating reserve of 1350MW to compensate for the lost output from one Darlington generating unit and 50% of a second Darlington unit, the resources should be adequate to compensate for the re-preparation actions identified above.

To prepare the system for the critical contingency, the Bruce Special Protection System would need to be armed to initiate the rejection of two Bruce B units together with all the remaining wind-turbine projects. In addition measures would need to be implemented to automatically reduce the transfers across the Negative BLIP Interface to approximately zero to ensure that the post-contingency flows on the 230kV circuits between Longwood TS and Buchanan TS would remain within their long-term emergency ratings. This reduction could be achieved through a reduction of the transfers across the Ontario-Michigan Interface and/or the rejection of generation capacity in the Sarnia-Windsor area.

These actions would result in a resource deficiency of approximately 2300MW, derived as follows:

• Removal from service of all the wind-turbine projects		925MW
• Rejection of two Bruce B generating units		1640MW
• Reduction of the transfers across the Negative BLIP Interface to zero		~ 1150MW
• Change in the transmission system losses		- 50MW
	Sub-total	*3665MW*
Less the normal 30-minute Operating Reserve		1350MW
	Resulting Deficiency	*~ 2300MW*

To address this resource deficiency a combination of increased output from the Ontario generating resources that remain available together with load rejection would therefore be required.

Although the re-preparation of the system was only examined for the condition with 50% compensation of the 500kV circuits, the requirements are expected to be similar for lower levels of series compensation.

7. Bruce Special Protection System

With seven Bruce units in-service together with the new wind-turbine projects, the Bruce Special Protection System will need to be enhanced so that it can react to the following contingency conditions and provide the additional responses identified below:

Contingency conditions that need to be added to the Bruce SPS:

- 500kV circuit N582L
- 230kV circuits B4V & B5V: both single- and double-circuit contingencies
- 230kV circuits B22D & B23D: both single- and double-circuit contingencies

Responses that need to be added to the Bruce SPS:

- Cross-tripping of the 115kV breaker A1A2 at Stayner TS
- Generation Rejection for individual wind-turbine projects (or selected groups)
- Switching of the new shunt capacitor banks
- Additional load rejection selections (if the amount provided by the present selections is insufficient)

8. *Load Flow Analysis with Eight Bruce Units*

Analysis has shown that regardless of the level of series compensation installed, it would not be possible to accommodate all eight Bruce units and all of the committed wind-turbine projects without having to employ generation rejection in response to a double-circuit contingency involving the 500kV circuits B560V & B561M.

Furthermore, having to reject the equivalent of at least one Bruce unit in response to a first contingency would compound the problems associated with re-preparing the system for a subsequent contingency, and is expected to require substantially more load to be armed for rejection.

In order to comply with the 'no generation rejection for a first contingency' criterion, it was therefore concluded that new 500kV transmission facilities would be required to accommodate all eight Bruce units.

The Assessment examined two alternatives:

Alternative 1. A new 500kV single-circuit line between Longwood TS and Middleport TS
Estimated length ~ 150km

Alternative 2.

Option i. A new 500kV double-circuit line between the Bruce Complex and Milton TS
Estimated length ~ 176km

Option ii. A new double-circuit 500kV line between the Bruce Complex and Essa TS
Estimated length ~ 182km

Alternative 1.

To accommodate the new 500kV line on the existing right-of-way it was assumed that the existing 230kV single-circuit line M31W would have to be removed.

To maintain post-contingency transient stability, the 500kV circuits between the Bruce Complex and Longwood TS would need to be compensated to at least **20%** while those between Longwood TS and Nanticoke SS and between Longwood TS and Middleport TS would need to be compensated to at least **10%.**

To limit the post-contingency flows through the 230kV circuits B4V & B5V, the level of compensation on the 500kV circuits would need to be increased to 40%. With this level of compensation installed, the post-contingency flows on the section of the 230kV circuits B4V & B5V between the Melancthon Projects and Orangeville TS would be within their 15km/hr wind-speed rating of 1590A.

Alternative 2.

Option i. For this Option there would be no requirement to install series capacitors on any of the 500kV circuits either to maintain post-contingency transient stability or to avoid post-contingency overloading.

Option ii. Similarly for this Option, there would be no requirement to install series capacitors on any of the 500kV circuits.

Remedial measures would, however, be required to raise the operating temperatures of the two existing Essa-to-Claireville 500kV lines. Since each of these lines is presently rated at only 1900MVA, they would be inadequate for the projected post-contingency flows of approximately 2600MVA per circuit.

Comparison of the Alternatives

Alternative 1 would be substantially inferior to Alternative 2 for the following reasons:

- It would require the 500kV circuits to be series compensated to a level of 40%.

  For Alternative 2, none of the 500kV circuits would require series compensation.

- It would require higher levels of post-contingency reactive support to be provided from the synchronous condensers at Nanticoke GS.

  Approximately 950MVAr of support would need to be available, whereas Alternative 2 would require a maximum of approximately 275MVAr.

- It would result in additional post-contingency losses of approximately 400MW, while for Alternative 2 the increased losses would be approximately 160MW.

- It would continue to present challenges for the re-preparation of the system to position it for any subsequent contingency.

  Since Alternative 2 involves the installation of an additional, independent path from the Bruce Complex, a sustained outage involving circuits B560V & B561M would essentially return the system to the status quo. For this, the consequences of a single element contingency would be much less severe.

Of the two options for terminating the new 500kV double-circuit line from the Bruce Complex, the one with the line terminated at Milton TS instead of at Essa TS would have the advantage of avoiding the need to uprate the two 500kV lines between Essa TS and Claireville TS.

However, in all other respects, the performance of the two options considered for Alternative 2 would be similar.

9. Synchronous Condensers

For the initial period with seven Bruce units together with 925MW of wind-turbine generation capacity in-service, the post-contingency reactive support requirements could be provided by converting a minimum of three units at Nanticoke GS to synchronous condenser operation. However, to cater for maintenance and forced outages of these units, it would be prudent to convert four of them to synchronous condenser operation.

Once the new 500kV double-circuit line is placed in-service to coincide with all eight Bruce units being in operation, the reactive support that would be required could be provided from a single synchronous condenser. However, as before, it would be prudent to convert an additional unit to provide redundancy.

Since the new 500kV line is required to be in-service no later than the end-2011, the period over which four synchronous condensers would need to be available would be a maximum of three years.

The IESO has therefore recommended that consideration be given to providing a portion of the reactive power requirements from Static VAr Compensators (SVCs). This would limit the number of units at Nanticoke GS that would have to be converted to synchronous condenser operation. In addition, once the new 500kV line is placed in-service and the reactive support requirements are reduced, any surplus SVC capacity could be relocated to other areas of the system that require dynamic voltage support.

10. Recommendations

- The ABB Study that was commissioned by Hydro One has determined that sub-synchronous resonance (SSR) issues associated with the installation of series capacitors in the 500kV circuits connected to either the Bruce Complex or Nanticoke GS could be avoided if the level of compensation were to be maintained below 40%. This would avoid the need to employ mitigating measures such as using thyristor controlled series capacitors (TCSCs) for a portion of the series capacitor installation.

  The IESO has determined that installing 30% series compensation would avoid the need to uprate the 500kV circuit N582L although it would result in post-contingency flows on the section of circuits B4V & B5V between Hanover TS and Orangeville TS that would exceed the 15km/hr wind-speed rating of these circuits.

  The IESO is therefore recommending that the condition of this section of circuits B4V & B5V be examined to determine whether the line could be uprated for operation at a conductor temperature of 127^{o}C.

If circuits B4V & B5V can be uprated, then the IESO's preference would be to adopt a level of 30% compensation for the series capacitors that it is proposed to install on the 500kV circuits between the Bruce Complex and Longwood TS and between Longwood TS and Nanticoke SS.

- Since extensive modifications to the Bruce SPS are expected to be necessary to provide the additional flexibility that will be required, and in recognition of the complexity of the existing scheme and the associated difficulty of implementing changes, the IESO would support a change to a matrix-based design, similar to that which has been used for other SPSs.

- In the accompanying analysis, extensive use has been made of the 15km/hr wind-speed ratings for the 230kV circuits B4V & B5V in assessing whether post-contingency overloading is expected to occur.

  Since the prevailing ambient conditions are expected to have a major influence on these ratings and therefore on the operation of the system with particular emphasis on the post-contingency responses that are adopted, the IESO has recommended that these circuits be equipped with real-time monitoring.

- Review the capability of the Independent Phase Controlled Compensators at Norfolk TS and Tillsonburg TS to determine whether their capacity will be adequate to address the voltage imbalances arising from the increased flows that are expected on circuit N582L once the series capacitors have been installed.

11. Notification of Approval of the Connection Proposal

Subject to the completion of the Customer Impact Assessment and the satisfactory resolution of any issues that it may raise, the IESO has concluded that the following work will have no materially adverse effect on the IESO-controlled grid:

- the installation of series capacitors in the Bruce-to-Longwood and the Longwood-to-Nanticoke 500kV circuits, whether at the 50% or 30% compensation level, and subject to appropriate action to uprate either the 500kV circuit N582L (for 50%) or the 230kV circuits B4V & B5V (for 30%).
- the installation of 230kV shunt capacitor banks at Middleport TS, Nanticoke TS, Detweiler TS & Orangeville TS
- the conversion of up to four units at Nanticoke GS to synchronous condenser operation, and/or the installation of SVCs to provide a portion of the reactive power support that will be required.
- enhancement of the Bruce SPS to expand the number of contingencies to which it can respond as well as the range of actions that can be automatically initiated in response to these contingencies.

It is therefore recommended that a Notification of Conditional Approval to Connect be issued for this Project.

HYDRO ONE NETWORKS Inc.

Installation of Series Compensation in the 500kV Circuits Associated with the Bruce Complex

1. Background Information

The need to increase the capability of the existing transmission system to accommodate additional generating capacity has arisen as a result of a number of recent decisions. Since these decisions have formed the basis for this assessment they have been summarised below.

Renewables I RFP

On 24th November 2004, the Government of Ontario announced the list of projects that had been selected for development in response to the Renewables I RFP. Of the 395MW of new generating capacity that was selected, approximately 255MW is to be incorporated into the system directly associated with the Bruce Complex.

Bruce Units 1 & 2

On 21st March 2005, the Government of Ontario announced that tentative agreement had been reached for the restart of the remaining two generating units at the Bruce Complex.

2500MW New Clean Energy RFP

On 13th April 2005, the Government of Ontario announced that the following projects had been selected for development under the 2500MW RFP for New Clean Generation & Demand-side Projects:

- Greenfield Energy Centre Capacity: 1005MW Location: Sarnia-Lambton
- St Clair Power Capacity: 570MW Location: Sarnia-Lambton
- GTAA Project Capacity: 90MW Location: Mississauga

Hydro One Proposal

In response to the preceding announcements, Hydro One Networks submitted an application to the IESO in April 2005 for a Connection Assessment of their proposal to install series capacitors in the 500kV circuits associated with the Bruce Complex. The intent is to increase the capability of the system to accommodate the additional generating capacity that is to be developed in response to the Government of Ontario's 'off-coal' Policy.

2500MW New Clean Energy RFP (Continued)

On 30th May 2005, the Government of Ontario announced that the Greenfield North & the Greenfield South Projects, each with a capacity of 280MW, had also been selected for development under the 2500MW New Clean Generation RFP.

On 12th August 2005, the Ontario Power Authority announced that mutual agreement had been reached with the Greenfield North Power Corporation not to proceed with a Clean Energy Supply contract for the Greenfield North Project.

Lambton GS & Nanticoke GS

On 15th June 2005, the Government of Ontario announced that Lambton GS, with a capacity of 1975MW would close at the end-2007 and that the generating units at Nanticoke GS, with a combined capacity of 3938MW would be successively retired during 2008 and up to early-2009.

Bruce Units 1 & 2

On 17th October 2005, the Government of Ontario announced that formal agreement had been reached with Bruce Power Inc. for the refurbishment of Units 1 & 2 at the Bruce A nuclear generating facility, near Kincardine. Once these two units are operational in 2009 they are expected to increase the flow away from the Bruce Complex by approximately 1500MW.

West GTA

On 28th October 2005, the Ontario Power Authority issued a news release stating:

i. that a Request for Qualification had been issued for 1000MW of new electricity supply in the west GTA to address overloading of the auto-transformers at Trafalgar TS, and

ii that a directive had been issued by the Ministry of Energy to secure up to 900MW of new generating capacity at the Sithe-Goreway facility to address overloading of the auto-transformers at Claireville TS.

Renewables II RFP

On 21st November 2005, the successful projects under the Government of Ontario's Renewables II RFP were announced. The total capacity of the new projects is 975MW, of which approximately 566MW is to be incorporated into the system directly associated with the Bruce Complex. In addition, a further 101MW is to be developed at Port Alma in south-western Ontario which will have a direct effect on the transfers across the Negative-BLIP (Buchanan-Longwood Input) Interface.

2. Hydro One Proposal for Series Capacitors

Hydro One's proposal, as submitted for assessment, included the installation of series capacitors at the approximate mid-point of the following circuits, to provide the level of compensation as indicated for the circuit reactance:

500kV Circuit	*Route*	*Level of Compensation*
B560V	Bruce A to Claireville TS	10%
B561M	Bruce B to Milton TS	10%
B562L	Bruce A to Longwood TS	70%
B563L	Bruce B to Longwood TS	70%
N582L	Longwood TS to Nanticoke GS	70%

The proposed locations for the series capacitors are shown in Diagram 1.

3. IESO's Preliminary Review of the Proposal

In the analysis in support of the 10-Year Outlook that was issued on 8th July 2005, the IESO determined that additional reactive power support would be required within the Detweiler area to ensure that an acceptable voltage profile could be maintained following the simultaneous loss of the Bruce to Claireville and Bruce to Milton 500kV circuits.

The new facilities that the IESO proposed should be included with the series capacitors were as follows:

- A 250MVAr 230kV shunt capacitor bank at Detweiler TS
- A 250MVAr 230kV shunt capacitor bank at Orangeville TS

- A 230/115kV auto-transformer at Cambridge-Preston TS to interconnect the 230kV & 115kV systems in the immediate area
- A 500/230kV TS on the right-of-way of the 500kV circuits between Middleport TS and Milton TS/ Claireville TS, together with a new 230kV connection between the TS and Cambridge-Preston TS.
- A 500/230kV TS at Bellwood Junction, on the right-of-way of the 500kV circuits between Bruce GS and Claireville TS/Milton TS to interconnect the 500kV & 230kV systems in the immediate area.

Diagram 2 shows the facilities for enhancing the system in the Detweiler area that had been proposed in the 10-Year Outlook.

In addition, the IESO recommended that shunt capacitor banks (with a nominal rating of between 400MVAr & 500MVAr) be installed at Middleport TS and that two (or more) of the existing generating units at Nanticoke GS be converted to synchronous condenser operation to provide post-contingency voltage support in the Nanticoke/ Middleport area.

4. Revised Requirements

Subsequent analysis has shown the following:

- That the series capacitors proposed in circuits B560V & B561M in the vicinity of Bellwood Junction would only be required to support transfers to Michigan following the loss of the Bruce to Longwood 500kV circuits, B562L & B563L. Since Ontario is not expected to be in a position to provide substantial power exports to Michigan in the foreseeable future, it has been agreed with Hydro One that these series capacitors should not form part of the current proposal.
- That the proposed 500/230kV interconnection at Bellwood Junction would have only limited benefit particularly since it would be removed from service for the critical contingency involving the loss of both 500kV circuits to which it is connected. It has therefore been removed from the 'reference' proposal.
- That while the 500/230kV TS on the right-of-way of the 500kV circuits between Middleport TS and Milton TS/Claireville TS is expected to be required to address local area supply deficiencies, it is not essential for maintaining an acceptable voltage profile following 500kV contingencies. It has therefore been removed from the 'reference' proposal.

  However, it has been confirmed that the 230/115kV auto-transformer at Cambridge-Preston TS is necessary to support the 115kV system supplied from Detweiler TS under contingency conditions involving the 500kV system. It has therefore been retained in the 'reference' proposal.
- That rather than concentrating all of the shunt capacitors at Middleport TS, it would be beneficial to install additional shunt capacitors at Nanticoke GS so as to limit the post-contingency synchronous condenser requirements at that GS.

  [OPG has notified the IESO that the maximum reactive power output that can be provided from each unit, measured at the transformer HV terminals, is 375MVAr. This would correspond to an output of approximately 400MVAr at the generator terminals.

  In the load flow diagrams attached to this report, the MVAr values shown are those at the generator terminals]

Diagram 3 shows the 'reference' proposal that was subsequently adopted for this assessment.

This Diagram also shows the Negative-BLIP Interface which is used to monitor the combined transfers eastwards on the 230kV circuits originating from Buchanan TS together with the net transfers eastwards on the 500kV circuits at Longwood TS. The present operational limit for this Interface is 1500MW.

5. *Study Constraints*

This assessment was subject to the following constraints:

- No generation rejection was to be employed for a first contingency.
- During the period between April-2009 and the end-2011, a maximum of seven units were to be assumed to be in operation at the Bruce Complex.

  Although Units G1 & G2 are both scheduled to return to service during 2009, other units at the Bruce Complex are scheduled to be removed from service for maintenance. Consequently, the earliest that all eight units are expected to be operational is December-2011.

- From December-2011 onwards, eight Bruce units were to be assumed to be in-service.
- There should be no adverse impact on Ontario's import capability via its Interconnections.

6. *Study Assumptions*

The following assumptions were adopted for this assessment:

- The Load Flow Analysis would concentrate on the post-contingency *steady-state* condition

  Since no generation rejection was to be initiated in response to first contingencies, the critical post-contingency condition for the system would therefore correspond to the situation with loads restored to their pre-contingency values.

  Loads were therefore modelled as *Constant MVA.*

  All of the transformer tap-changers that are under automatic control were allowed to move and post-contingency switching of shunt capacitors and reactors were allowed to occur.

- The transfers on the Interconnections would be restored to their pre-contingency levels.

  [For this assessment, the transfers into Ontario via the Interconnections were set at the following levels:

Michigan to Ontario	1500MW, and	
New York to Ontario	1400MW	(1200MW at Niagara and 200MW at St Lawrence)]

- The increased losses on the transmission system would be supplied from the 30-minute operating reserve.

  Following the loss of the 500kV circuits, B560V & B561M, and with no generating units rejected, there would be a significant increase in the transmission losses. It was assumed that these losses would be supplied internally from those generating units providing operational reserve, thereby allowing the transfers on the Interconnections to be returned to their pre-contingency levels.

- The 'emergency' ratings would be used for the transmission lines.

  These ratings correspond to the continuous *[long-term emergency]* rating at a conductor operating temperature of 127^{o}C, or at the sag temperature, if this is lower.

- The following generating facilities would be assumed to be out-of-service:
  i. Lambton GS
  ii. Nanticoke GS (except as synchronous condensers)

- The following generation facilities would be assumed to be in-service:

i.	Greenfield Energy Centre	1005MW	
ii.	St Clair Power	570MW	
iii.	GTAA Project	90MW	
iv.	Greenfield South Project	280MW	
v.	Sithe-Goreway Project	1000MW	
vi.	Downtown (Leaside Sector)	500MW	
vii.	'Trafalgar' Project	1000MW	(when all other resources are insufficient to meet the system demand.)

- A total of 925MW of wind-turbine generation capacity would be included in the system model, consisting of the following projects:

Renewables I RFP

i.	Erie Shores Wind Farm	99.0MW
ii.	Kingsbridge Wind Power Project	39.6MW
iii.	Melancthon Grey Wind Project	67.5MW
iv.	Blue Highlands Wind Farm	49.5MW
	Sub-total	*255.6MW*

Renewables II RFP

i.	Kingsbridge II Wind Power Project	158.7MW
ii.	Kruger Energy Port Alma	101.2MW
iii.	Leader Wind Power Project A	100.7MW
iv.	Leader Wind Power Project B	99.0MW
v.	Melancthon II Wind Project	132.0MW
vi.	Ripley Wind Power Project	76.0MW
	Sub-total	*667.6MW*
	TOTAL	*923.2MW*

7. Thermal Ratings

Diagram 4 provides details of the transmission facilities in the Bruce-to-Toronto area, as well as the thermal ratings that were used in this assessment.

The ratings for those transmission facilities that were of particular concern as to their ability to support the post-contingency transfers have been summarised in Table 1:

In this Table, all ratings have been determined for an ambient temperature of 35^{o}C, with a wind speed of **0 to 4km/hr**.

TABLE 1	*Long-Term Emergency Ratings for the 'Critical' Circuits*		
Circuits	***Sag Temp***	***Long-Term 'Emergency' Rating at 127^oC or Sag Temperature, if lower***	***MVA Rating***
500kV circuit N582L			
Longwood TS to Nanticoke GS	127^oC	3660A	3423MVA at 540kV
500kV circuits E510V & E511V			
Essa TS to Claireville TS	78^oC	2030A	1898MVA at 540kV
230kV circuits B4V & B5V			
Bruce to Hanover TS	127^oC	1430A**	594MVA at 240kV
Hanover TS to Orangeville TS	104^oC	1180A	491MVA at 240kV
115kV circuit S2S			
Owen Sound to Meaford	150^oC	770A	161MVA at 121kV
Meaford to Stayner	128^oC	770A	161MVA at 121kV
115kV circuit S2E			
Stayner to Essa	150^oC	770A	161MVA at 121kV

Note ** Operation at this current is limited to 50 hours per year because the conductors are classified as of 'high-aluminum content'

Hydro One has indicated that it should be possible to increase the ground clearances on circuit N582L to allow the conductors to be operated to a maximum (sag) temperature of 150^oC.

However, although this would provide an enhanced rating of ***4110A*** *(3844MVA at 540kV), operation at this temperature is restricted to a maximum of* ***3 hours per year*** *since it would result in accelerated annealing of the conductors, thereby reducing the overall life expectancy of the line.*

230kV Circuits B4V & B5V

The two Leader Wind Projects totalling 200MW and the two Melancthon Wind Projects, also totalling 200MW are to be incorporated on to the 230kV circuits B4V & B5V.

The two Leader Wind Projects are to be incorporated on to the section of these circuits between the Bruce Complex and Hanover TS. The two Melancthon Wind Projects are to be incorporated on to the lower-rated section of these circuits between Hanover TS and Orangeville TS.

In recognition that the wind-turbine projects require winds in excess of 8m/sec (~ 30km/hr) to produce approximately half their peak output, the IESO's Transmission Assessment Criteria state that:

> *For connection assessments, transmission line ratings will be calculated using a wind-speed of 15km/hr instead of the usual 4km/hr value for transmission facilities within a 50km radius of the proposed wind generator.*

The following Table provides the ratings that would be applicable for the condition studied with the Leader & Melancthon Wind Projects operating at their maximum output.

It should also be noted that the 77km section of B4V & B5V between Hanover TS and Orangeville TS is limited to operation at a maximum conductor temperature of only 104^{o}C.

Ratings have also been provided for operation of this section at a maximum conductor temperature of 127^{o}C, although no investigation has been conducted by Hydro One to determine whether this would be feasible.

TABLE 2	***Effect of Wind-Speed on Line Ratings on the 230kV Circuits B4V & B5V***			
Conductor	***Sag Temp***	***Wind Speed***	***Long-term 'Emergency' Rating at 127^{o}C or the Sag Temperature, if lower***	***MVA Rating at 240kV***
Bruce Complex to Hanover TS 48.2km				
1277.5kcmil 42/7	93^{o}C / 127^{o}C**	4km/hr	1080A / 1430A**	449 / 594MVA
		15km/hr	1490A / 1870A**	619 / 777MVA
Hanover TS to Orangeville TS 77.2km				
1192.5kcmil 54/19	104^{o}C	4km/hr	1180A	490MVA
		15km/hr	1590A	661MVA
	127^{o}C	4km/hr	1400A	582MVA
		15km/hr	1830A	760MVA

Note ** Operation at this current is limited to 50 hours per year because these conductors are classified as of 'high-aluminum content'

8. Area Loads

During the summer-2005, for which an 'extreme-weather' peak demand of 26931MW had been forecast, the primary demand on the Ontario system peaked at 26160MW.

Furthermore, the maximum transfers into the Detweiler area via the 230kV transmission system to supply the loads in Kitchener, Waterloo, Cambridge, Guelph & Orangeville peaked at 1405MW during the summer-2005.

For this assessment, the flow into the Detweiler area was therefore adjusted to produce a net infeed of 1400MW for the reference load flow study case with a primary demand of 26000MW.

Subsequent studies were then performed with the system loads scaled so as to produce primary demands of 25000MW, 27000MW, 28000MW and 29000MW.

The 29000MW case was intended to correspond to the summer-2013, for which an 'extreme-weather' peak demand of 29029MW has been forecast. [from the IESO 10-Year Demand Forecast, issued on 8th July 2005]

9. Transient Stability Analysis

To establish what minimum levels of series compensation would be acceptable, transient stability studies were performed for normally-cleared line-to-line-ground (LLG) faults on the 500kV circuits B560V & B561M at Willowcreek Junction (approximately 18.3km from the Bruce Complex). For these studies, different levels of series compensation were assumed to be installed on the Bruce-to-Longwood and Longwood-to-Nanticoke 500kV circuits.

With the series compensation maintained at the levels indicated in Table 3 for each of the different generation scenarios that were examined, stable responses, with acceptable machine damping, were obtained. The minimum post-contingency voltages also met the IESO's criteria of:

i. Remaining above 70% of the nominal voltage, and

ii. Not falling below 80% of the nominal voltage for more than 250 milliseconds within the 10 second period following the fault.

The level of compensation required to maintain transient stability following a 500kV double-circuit contingency for the condition with either seven or eight Bruce units in operation, together with wind-turbine generation facilities totalling 925MW, can therefore be summarised as follows:

With Seven Bruce units in operation + 925MW of wind-turbine generation

- the minimum amount of series compensation that would be acceptable on the existing transmission facilities would be **20%** on the Bruce-to-Longwood circuits and **20%** on the Longwood-to-Nanticoke circuit.

With Eight Bruce units in operation + 925MW of wind-turbine generation

- with no new transmission facilities, the minimum amount of series compensation would need to be increased to **40%** on the Bruce-to-Longwood circuits and **30%** on the Longwood-to-Nanticoke circuit.
- with a new 500kV single-circuit transmission line between Longwood TS and Middleport TS, the minimum amount of series compensation that would be acceptable would be **20%** on the Bruce-to-Longwood circuits and **10%** on both the existing Longwood-to-Nanticoke circuit and the new Longwood-to-Middleport circuit.

Transient stability studies were also performed with a new 500kV double-circuit line between the Bruce Complex and either Essa TS or Milton TS. These confirmed that transient stability could be maintained following the loss of either the existing Bruce-to Milton 500kV double-circuit line or the new 500kV double-circuit line with ***no series compensation installed.***

Series Compensation Requirements with no new wind-turbine generation

With no new wind-turbine generating facilities in-service, the level of series compensation that would be required to maintain transient stability without having to employ post-contingency generation rejection in response to the simultaneous loss of the Bruce-to-Claireville & Bruce–to-Milton circuits would be as follows:

With Eight Bruce units in operation & no wind-turbine generation

- the minimum amount of series compensation that would be acceptable on the existing transmission facilities would be **20%** on the Bruce-to-Longwood circuits and **10%** on the Longwood-to-Nanticoke circuit.

TABLE 3 Summary of Transient Stability Analysis: With no new transmission lines

Levels of Compensation Required on the Bruce-to-Longwood **(BxL)** *and Longwood-to-Nanticoke* **(NxL)** *Circuits to Maintain Transient Stability*

	Generation Scenario	*Generation Output Less Station Service Load*		*FABC Transfer Including 10% Margin*	*Compensation Required*
1.	**Six** Bruce Units & No Wind-turbine Generation	2 x 805 + 4 x 940 - (2 x 55 + 4 x 50 + 25)	5035MW	5540MW	***None***
2.	**Six** Bruce Units & 925MW of Wind-turbine Generation	2 x 805 + 4 x 940 + 925 - (2 x 55 + 4 x 50 + 25)	5960MW	6560MW	***None***
3.	**Seven** Bruce Units & No Wind-turbine Generation	3 x 805 + 4 x 940 - (3 x 55 + 4 x 50 + 25)	5785MW	6370MW	***None***
4.	**Seven** Bruce Units & 925MW of Wind-turbine Generation	3 x 805 + 4 x 940 + 925 - (3 x 55 + 4 x 50 + 25)	6710MW	7380MW	***BxL: 20% + NxL: 20%***
5.	**Eight** Bruce Units & No Wind-turbine Generation	4 x 805 + 4 x 940 - (4 x 55 + 4 x 50 + 25)	6535MW	7190MW	***BxL: 20% + NxL: 10%***
6.	**Eight** Bruce Units & 925MW of Wind-turbine Generation	4 x 805 + 4 x 940 + 925 - (4 x 55 + 4 x 50 + 25)	7460MW	8210MW	***BxL: 40% + NxL: 30%***

Summary of Transient Stability Analysis: With a new 500kV transmission line between Longwood TS and Middleport TS (LxM)

7.	**Eight** Bruce Units & 925MW of Wind-turbine Generation	4 x 805 + 4 x 940 + 925 - (4 x 55 + 4 x 50 + 25)	7460MW	8210MW	***BxL: 20% + NxL: 10% + LxM: 10%***

10. Load Flow Analysis: With Seven Bruce units & 925MW of wind-turbine generation

Negative-BLIP Transfers

Following the planned shut-down of Lambton GS in 2007 and the development of the two new ‘Clean Energy Supply’ generating projects in the Sarnia – Lambton area, the residual power available to the remainder of the system will depend on the load within south-western Ontario as well as the level of transfers into Ontario across the Ontario-Michigan Interface.

Consequently, with the Michigan-Ontario transfers maintained at their maximum of 1500MW, the net transfers across the Negative-BLIP Interface will decline as the primary demand, and by extension, the load in south-western Ontario is increased.

Preliminary studies were therefore performed using the 25000MW primary demand case since it was found to result in transfers across the Negative-BLIP Interface that were close to the 1500MW limit.

10.1 With 70% / 70% Compensation

Diagrams 5 & 6 show the pre- and post-contingency results following the loss of circuits B560V & B561M due to a 500kV double-circuit contingency.

For this study, the level of series compensation was set at **70%** in the Bruce-to-Longwood and the Longwood-to-Nanticoke circuits as proposed in the Hydro One application.

The critical flows for this condition are shown in the Table below:

Primary Demand: 25000MW *No. of Bruce Units: 7* *Negative BLIP Flow: 1478MW*

Compensation: 70% & 70%

Condition	*Losses*	*Synchronous Condenser Output*	*500kV Circuit N582L*		*Flows on B4V/B5V*			*Flows on S2S*	
			Rating	*4110A*	Rating		*A* 1430A; *B* 1180A	*Rating: 770A*	
			MW/MVAr	*Amps*		*MW/MVAr*	*Amps*		*Amps*
Pre-cont.	820.6MW	54.0MVAr	2397/ -500	2582A	*A*	323/ 9	751A	*C*	430A
					B	360/ -65	853A	*D*	658A
Post-cont.	1223.5MW	970.0MVAr	4223/ -592	4555A	*A*	463/ 76	1089A	*C*	673A
	Δ 402.9MW	*Δ 916.0MVAr*			*B*	491/ -96	1217A	*D*	893A

Note: *A* refers to the section between Bruce and Hanover TS, and
B refers to the section between Hanover TS and Orangeville TS.

C refers to the section between Owen Sound TS and the Blue Mountain Wind Project
D refers to the section between the Blue Mountain Wind Project and Meaford TS

The results in the Table show that even with the sag temperature of the 500kV circuit N582L increased to its maximum value of 150^{o}C, the post-contingency flow would be expected to exceed its enhanced rating by 445A.

Similarly, the post-contingency flows on the sections of the 230kV circuits B4V & B5V between the Melancthon Wind Projects and Orangeville TS are shown to exceed their ‘4km/hr’ ratings. However, since the high flows on these circuits are due, in part, to the output from the Leader and Melancthon Wind Projects, then the appropriate rating would be 1590A for a 15km/hr wind-speed (from Table 2).

The projected post-contingency flow of 1217A would therefore be well within this rating.

The post-contingency flow on the section of circuit S2S between the Blue Mountain Wind Project and Meaford TS is also shown to exceed its emergency rating at 127^{o}C. This would require either the automatic post-contingency rejection of the Blue Mountain Wind Project and/or the automatic cross-tripping of the A1A2 in-line breaker at Stayner TS to open the connection between circuits S2S & S2E.

It is also worth noting the voltages that were recorded at the terminals of the series capacitor installations, both pre- and post-contingency, for this level of compensation.

Voltages Recorded at the Series Capacitor Installations: *with 70% / 70% compensation*		
500kV Circuit	*Pre-contingency*	*Post-contingency*
B562L	558.1kV	568.1kV
B563L	558.2kV	569.1kV
N582L	566.7kV	577.4kV

10.2 With 60% / 60% Series Compensation

In order to reduce the post-contingency flow on the 500kV circuit N582L, the level of series compensation on both the Bruce-to-Longwood and the Longwood-to-Nanticoke 500kV circuits was reduced to **60%**.

The results from these studies for the pre- and post-contingency conditions following the loss of circuits B560V & B561M due to a 500kV double-circuit contingency are shown in Diagrams 7 & 8, respectively.

The critical flows with the reduced level of series compensation are shown in the Table below:

<table>
<tr><td colspan="11">Primary Demand: 25000MW   No. of Bruce Units: 7   Negative BLIP Flow: 1479MW
Compensation: 60% & 60%</td></tr>
<tr><td rowspan="4">Condition</td><td rowspan="4">Losses</td><td rowspan="4">Synchronous Condenser Output</td><td colspan="2">500kV Circuit N582L</td><td colspan="4">Flows on B4V/B5V</td><td colspan="2">Flows on S2S</td></tr>
<tr><td rowspan="2">Rating</td><td rowspan="2">4110A</td><td colspan="2" rowspan="2">Rating</td><td>A</td><td>1430A</td><td colspan="2" rowspan="2">Rating: 770A</td></tr>
<tr><td>B</td><td>1180A</td></tr>
<tr><td>MW/MVAr</td><td>Amps</td><td colspan="2">MW/MVAr</td><td colspan="2">Amps</td><td colspan="2">Amps</td></tr>
<tr><td rowspan="2">Pre-cont.</td><td rowspan="2">807.8MW</td><td rowspan="2">-2.0MVAr</td><td rowspan="2">2158/ -376</td><td rowspan="2">2315A</td><td>A</td><td>334/ 13</td><td colspan="2">775A</td><td>C</td><td>446A</td></tr>
<tr><td>B</td><td>370/ -67</td><td colspan="2">879A</td><td>D</td><td>674A</td></tr>
<tr><td rowspan="2">Post-cont.</td><td>1211.4MW</td><td>968.0MVAr</td><td rowspan="2">3982/ -348</td><td rowspan="2">4299A</td><td>A</td><td>499/ 98</td><td colspan="2">1181A</td><td>C</td><td>754A</td></tr>
<tr><td>Δ 403.2MW</td><td>Δ 970.0MVAr</td><td>B</td><td>525/ -109</td><td colspan="2">1318A</td><td>D</td><td>997A</td></tr>
</table>

Note: *A* refers to the section between Bruce and Hanover TS, and
B refers to the section between Hanover TS and Orangeville TS.

C refers to the section between Owen Sound TS and the Blue Mountain Wind Project
D refers to the section between the Blue Mountain Wind Project and Meaford TS

These results show that while a change in the level of compensation on the 500kV circuits to **60%** would achieve a reduction of 255MW in the post-contingency flow on circuit N582L, its enhanced thermal rating would still be exceeded. In addition, the post-contingency flows appearing on the 230kV circuits B4V & B5V would increase as a result of the lower level of compensation on the 500kV circuits.

The lower level of compensation would also result in the post-contingency flow on the section of circuit S2S between the Blue Mountain Wind Project and Meaford TS exceeding its emergency rating of 770A by approximately 230A. Since rejection of just the 49.5MW Blue Mountain Project would not be sufficient to address this degree of overloading, cross-tripping of the A1A2 in-line breaker at Stayner TS would therefore be unavoidable. However, opening this connection between circuits S2S & S2E would result in higher transfers on the remaining circuits which would therefore aggravate the overloading of circuit N582L.

The lower level of compensation would, however, result in reduced voltages at each series capacitor installation as shown by the values summarised in the following Table. As expected, the more noticeable declines in the voltages are shown to occur post-contingency.

Voltages Recorded at the Series Capacitor Installations: *with 60% / 60% compensation*				
500kV Circuit	*Pre-contingency*		*Post-contingency*	
		Reduction relative to 70% / 70% case		*Reduction relative to 70% / 70% case*
B562L	553.3kV	0.86%	555.3kV	2.25%
B563L	553.4kV	0.86%	555.7kV	2.35%
N582L	559.4kV	1.29%	561.7kV	2.72%

10.3 With 50% / 50% Compensation

Diagram 9 shows the pre-contingency results for the condition with a system primary demand of 25000MW. Diagram 10 shows the corresponding post-contingency results following the simultaneous loss of the 500kV circuits B560V & B561M.

The critical flows from these two studies are shown in the Table below:

Primary Demand: 25000MW *No. of Bruce Units: 7* *Negative BLIP Flow: 1476MW* ***Compensation: 50% & 50%***								
Losses	*Synchronous Condenser Output*	*500kV Circuit N582L*		*Flows on B4V/B5V*			*Flows on S2S*	
		Rating	*4110A*	Rating	*A*	*1430A*	*Rating: 770A*	
					B	*1180A*		
		MW/MVAr	*Amps*	*MW/MVAr*		*Amps*	*Amps*	
Pre-contingency.								*Diagram 9*
800.0MW	-36.8MVAr	1959/-295	2098A	*A*	342/ 16	795A	*C*	459A
				B	378/ -69	900A	*D*	687A
Post-contingency								*Diagram 10*
1208.4MW	987.2MVAr	3757/ -180	4072A	*A*	534/ 117	1269A	*C*	818A
Δ *408.4MW*	Δ *1024.0MVAr*			*B*	556/ -126	1414A	*D*	1062A

Note: *A* refers to the section between Bruce and Hanover TS, and
B refers to the section between Hanover TS and Orangeville TS.

C refers to the section between Owen Sound TS and the Blue Mountain Wind Project
D refers to the section between the Blue Mountain Wind Project and Meaford TS

These results show that with the level of compensation on the 500kV circuits reduced to 50%, the post-contingency flow on the 500kV circuit N582L could be maintained within its enhanced rating of 4110A for the condition with the Negative BLIP Flow close to its limit of 1500MW.

For the section of circuits B4V & B5V between the Melancthon Wind Projects and Essa TS, the projected flows would remain within the 15km/hr wind-speed rating of 1590A.

To address the excessive overloading of circuit S2S, particularly on the section between the Blue Mountain Wind Project and Meaford TS, it would be necessary to open the in-line breaker A1A2 at Stayner TS. However, since there is no provision within the existing Bruce SPS to automatically initiate the opening of the A1A2 breaker at Stayner TS in response to 500kV contingencies, the scheme would therefore need to be modified to provide this capability.

Diagram 11 shows the effect on the post-contingency results of opening this breaker.

The critical flows from this study are shown in the bottom portion of the Table below:

Primary Demand: 25000MW		*No. of Bruce Units: 7*			*Negative BLIP Flow: 1476MW*			
Compensation: 50% & 50%								
Losses	*Synchronous Condenser Output*	*500kV Circuit N582L*		*Flows on B4V/B5V*			*Flows on S2S*	
		Rating	*4110A*	Rating		*A* 1430A / *B* 1180A	*Rating: 770A*	
		MW/MVAr	*Amps*	*MW/MVAr*		*Amps*	*Amps*	
Pre-contingency							*Diagram 9*	
800.0MW	-36.8MVAr	1959/-295	2098A	*A*	342/ 16	795A	*C*	459A
				B	378/ -69	900A	*D*	687A
*Post-contingency: 115kV Circuit S2S Operated **CLOSED***							*Diagram 10*	
1208.4MW	987.2MVAr	3757/ -180	4072A	*A*	534/ 117	1269A	*C*	818A
Δ 408.4MW	*Δ 1024.0MVAr*			*B*	556/ -126	1414A	*D*	1062A
*Post-contingency: 115kV Circuit S2S Operated **OPEN** at Stayner TS*							*Diagram 11*	
1215.4MW	1060.0MVAr	3824/ -178	4155A	*A*	534/ 125	1274A	*C*	81A
Δ 415.4MW	*Δ 1096.8MVAr*			*B*	577/ -136	1476A	*D*	318A

Note: *A* refers to the section between Bruce and Hanover TS, and
B refers to the section between Hanover TS and Orangeville TS.

C refers to the section between Owen Sound TS and the Blue Mountain Wind Project
D refers to the section between the Blue Mountain Wind Project and Meaford TS

The results summarised in Diagram 11 show that opening the in-line breaker at Stayner TS would achieve the required reduction in the flows on circuits S2S but it would increase the post-contingency flows on circuits N582L, B4V and B5V. Since the post-contingency flow on the 500kV circuit N582L is shown to exceed the enhanced rating for this circuit, it would therefore be necessary to adopt either of the following responses:

- Initiate rejection of sufficient generating capacity to ensure that the new rating is respected, or
- Delay the restoration to their pre-contingency levels of the transfers across the Ontario-Michigan & Ontario-New York Interconnections.

  Analysis has shown that apart from a significant increase in the transmission losses, the simultaneous loss of the 500kV circuits B560V & B561M would result in a reduction of approximately 12.8% in the transfers from Michigan, with a corresponding increase in the transfers from New York. This reduction occurs as a direct consequence of the resulting increase in the impedance of the transmission path between Michigan and the major load centres in Ontario.

  For the condition with a pre-contingency transfer of 1500MW from Michigan, the 500kV double-circuit contingency would therefore result in this transfer being reduced to approximately 1310MW, assuming that all of the increased system losses are supplied from the 30-minute operating reserve. There would also be an equivalent *increase* in the transfers from New York of approximately 190MW.

Effect of Delaying the Restoration of the Post-Contingency Transfers Across the Interconnections

Diagram 12 shows the effect of maintaining the reduction of approximately 190MW in the post-contingency transfers across the Ontario-Michigan Interconnections, together with a corresponding increase in the Ontario-New York transfers, following a 500kV double-circuit contingency and the associated cross-tripping of the Stayner A1A2 breaker in the 115kV circuit S2S.

As before, the increased transmission system losses were assumed to be supplied internally from the 30-minute operating reserve.

The critical flows from this study are shown in the bottom portion of the Table below:

<table>
<tr><td colspan="9">Primary Demand: 25000MW   No. of Bruce Units: 7   Negative BLIP Flow: 1476MW
Compensation: 50% & 50%</td></tr>
<tr><td rowspan="4">Losses</td><td rowspan="4">Synchronous Condenser Output</td><td colspan="2">500kV Circuit N582L</td><td colspan="3">Flows on B4V/B5V</td><td colspan="2">Flows on S2S</td></tr>
<tr><td rowspan="2">Rating</td><td rowspan="2">4110A</td><td rowspan="2" colspan="2">Rating</td><td>A   1430A</td><td rowspan="2" colspan="2">Rating: 770A</td></tr>
<tr><td>B   1180A</td></tr>
<tr><td>MW/MVAr</td><td>Amps</td><td colspan="2">MW/MVAr</td><td>Amps</td><td colspan="2">Amps</td></tr>
<tr><td colspan="9">Pre-contingency   Diagram 9</td></tr>
<tr><td rowspan="2">800.0MW</td><td rowspan="2">-36.8MVAr</td><td rowspan="2">1959/-295</td><td rowspan="2">2098A</td><td>A</td><td>342/ 16</td><td>795A</td><td>C</td><td>459A</td></tr>
<tr><td>B</td><td>378/ -69</td><td>900A</td><td>D</td><td>687A</td></tr>
<tr><td colspan="9">Post-contingency: 115kV Circuit S2S OPEN at Stayner TS
PLUS No Restoration of the O-M & O-NY Transfers   Diagram 12</td></tr>
<tr><td>1188.4MW</td><td>983.2MVAr</td><td rowspan="2">3730/ -186</td><td rowspan="2">4043</td><td>A</td><td>530/ 119</td><td>1262A</td><td>C</td><td>81A</td></tr>
<tr><td>Δ 388.4MW</td><td>Δ 1020.0MVAr</td><td>B</td><td>573/ -136</td><td>1460A</td><td>D</td><td>317A</td></tr>
</table>

Note: *A* refers to the section between Bruce and Hanover TS, and
B refers to the section between Hanover TS and Orangeville TS.

C refers to the section between Owen Sound TS and the Blue Mountain Wind Project
D refers to the section between the Blue Mountain Wind Project and Meaford TS

These results show that, as long as the transfers across the Ontario-Michigan and Ontario-New York Interconnections are allowed to remain at their post-contingency levels, the post-contingency flow on circuit N582L could be maintained within its 'enhanced' rating of 4110A following the cross-tripping of circuit S2S.

The post-contingency flows on the section of circuits B4V & B5V between the Melancthon Wind Projects and Orangeville TS are also shown to remain within their **15km/hr** wind-speed rating of 1590A.

10.4 With 40% / 40% Compensation

The pre-contingency results for a system primary demand of 25000MW and with the 500kV circuits compensated to 40% are shown in Diagram 13. The corresponding post-contingency results following the simultaneous loss of the 500kV circuits B560V & B561M are shown in Diagram 14.

In this study the A1A2 breaker at Stayner TS has been assumed to be cross-tripped immediately post-contingency to open the connection between the 115kV circuits S2S & S2E. In addition, the transfers across the Ontario-Michigan and Ontario-New York Interconnections were kept at their post-contingency levels and not returned to their pre-contingency values.

The critical flows from these two studies are shown in the Table below:

<table>
<tr><td colspan="9">Primary Demand: 25000MW   No. of Bruce Units: 7   Negative BLIP Flow: 1476MW
Compensation: 40% & 40%</td></tr>
<tr><td rowspan="4">Losses</td><td rowspan="4">Synchronous Condenser Output</td><td colspan="2">500kV Circuit N582L</td><td colspan="3">Flows on B4V/B5V</td><td colspan="2">Flows on S2S</td></tr>
<tr><td rowspan="2">Rating</td><td rowspan="2">4110A</td><td colspan="2" rowspan="2">Rating</td><td>A 1430A</td><td colspan="2" rowspan="2">Rating: 770A</td></tr>
<tr><td>B 1180A</td></tr>
<tr><td>MW/MVAr</td><td>Amps</td><td colspan="2">MW/MVAr</td><td>Amps</td><td colspan="2">Amps</td></tr>
<tr><td colspan="9">Pre-contingency.   Diagram 13</td></tr>
<tr><td rowspan="2">796.1MW</td><td rowspan="2">-56.4MVAr</td><td rowspan="2">1794/-240</td><td rowspan="2">1919A</td><td>A</td><td>349/ 20</td><td>812A</td><td>C</td><td>460A</td></tr>
<tr><td>B</td><td>385/ -70</td><td>919A</td><td>D</td><td>700A</td></tr>
<tr><td colspan="9">Post-contingency: 115kV Circuit S2S OPEN at Stayner TS
PLUS No Restoration of the O-M & O-NY Transfers   Diagram 14</td></tr>
<tr><td>1192.2MW</td><td>1044.4MVAr</td><td rowspan="2">3511/ -95</td><td rowspan="2">3849A</td><td>A</td><td>562/ 140</td><td>1345A</td><td>C</td><td>81A</td></tr>
<tr><td>Δ 396.1MW</td><td>Δ 1100.8MVAr</td><td>B</td><td>603/ -154</td><td>1557A</td><td>D</td><td>317A</td></tr>
</table>

Note: *A* refers to the section between Bruce and Hanover TS, and
B refers to the section between Hanover TS and Orangeville TS.

C refers to the section between Owen Sound TS and the Blue Mountain Wind Project
D refers to the section between the Blue Mountain Wind Project and Meaford TS

While the lower level of series compensation is shown to result in a lower post-contingency flow on circuit N582L, it would still exceed its present long-term emergency rating of 3660A (corresponding to its sag temperature of 127^{O}C). Consequently, measures would still be required to increase the ground clearances for this line to provide a higher ‘enhanced’ rating of up to 4110A.

The lower level of compensation would also result in higher post-contingency flows on circuits B4V & B5V, although they are shown to remain just marginally within the **15km/hr** wind-speed rating of 1590A. Consequently, any further reduction in the level of compensation would be expected to require additional measures to increase the ratings of circuits B4V & B5V.

10.5 With 30% / 30% Compensation

With the level of series compensation on the 500kV circuits reduced to 30%, the results for the pre-contingency and the post-contingency conditions following a double-circuit contingency involving the 500kV circuits B560V & B561M are shown in Diagrams 15 and 16, respectively.

The post-contingency condition reflects the cross-tripping of the A1A2 breaker at Stayner TS to open the connection between the 115kV circuits S2S & S2E and the retention of the transfers across the Ontario-Michigan and Ontario-New York Interconnections at their post-contingency levels.

The critical flows from these two studies are shown in the Table below:

<table>
<tr><td colspan="9">Primary Demand: 25000MW   No. of Bruce Units: 7   Negative BLIP Flow: 1476MW
Compensation: 30% & 30%</td></tr>
<tr><td rowspan="4">Losses</td><td rowspan="4">Synchronous Condenser Output</td><td colspan="2">500kV Circuit N582L</td><td colspan="3">Flows on B4V/B5V</td><td colspan="2">Flows on S2S</td></tr>
<tr><td rowspan="2">Rating</td><td rowspan="2">4110A</td><td colspan="2" rowspan="2">Rating</td><td>A 1430A</td><td colspan="2" rowspan="2">Rating: 770A</td></tr>
<tr><td>B 1180A</td></tr>
<tr><td>MW/MVAr</td><td>Amps</td><td colspan="2">MW/MVAr</td><td>Amps</td><td colspan="2">Amps</td></tr>
<tr><td colspan="9">Pre-contingency.   Diagram 15</td></tr>
<tr><td rowspan="2">794.6MW</td><td rowspan="2">-68.8MVAr</td><td rowspan="2">1654/ -201</td><td rowspan="2">1770A</td><td>A</td><td>355/ 23</td><td>826A</td><td>C</td><td>469A</td></tr>
<tr><td>B</td><td>390/ -71</td><td>934A</td><td>D</td><td>710A</td></tr>
<tr><td colspan="9">Post-contingency: 115kV Circuit S2S OPEN at Stayner TS
PLUS No Restoration of the O-M & O-NY Transfers   Diagram 16</td></tr>
<tr><td>1199.0MW</td><td>1054.8MVAr</td><td rowspan="2">3314/ -21</td><td rowspan="2">3669A</td><td>A</td><td>592/ 161</td><td>1424A</td><td>C</td><td>81A</td></tr>
<tr><td>Δ 404.4MW</td><td>Δ 1123.6MVAr</td><td>B</td><td>630/ -172</td><td>1649A</td><td>D</td><td>317A</td></tr>
</table>

Note: *A* refers to the section between Bruce and Hanover TS, and
B refers to the section between Hanover TS and Orangeville TS.

C refers to the section between Owen Sound TS and the Blue Mountain Wind Project
D refers to the section between the Blue Mountain Wind Project and Meaford TS

At this level of series compensation, the post-contingency flow on circuit N582L is shown to be only marginally above (by 9A) the long-term emergency rating for this circuit. Since this is considered to be within acceptable tolerances, no measures would therefore be required to enhance the rating of this circuit if this level of series compensation were to be adopted.

However, since the post-contingency flows on circuits B4V & B5V are shown to be approximately 60A above their **15km/hr** wind-speed rating, these circuits would need to be uprated to increase their present sag temperature of only 104^{o}C.

As shown in Table 2, raising the sag-temperature for this line to 127^{o}C would provide long-term emergency ratings of 1400A and 1830A for wind-speeds of **4km/hr** and **15km/hr**, respectively.

10.6 Summary of Results for Different Levels of Series Compensation

The preceding studies show that employing levels of series compensation on the 500kV circuits between the Bruce Complex and Nanticoke SS that **exceed 50%** would result in excessive post-contingency flows on the 500kV circuit N582L. Even with the operational temperature of this circuit increased to 150^{o}C to provide an 'enhanced' rating of 4110A, these flows would still result in overloading.

For all of the studies, post-contingency overloading of the 115kV circuit S2S between Owen Sound TS and Orangeville TS was shown to be an issue. To address this, cross-tripping the A1A2 breaker at Stayner TS to break the connection between the 115kV circuits S2S & S2E was shown to be effective. However, with the interruption of this direct connection between Owen Sound TS and Essa TS, the flows on the 500kV circuit N582L and on the 230kV circuits B4V & B5V were shown to increase.

As discussed in Section 11 of this report, should the fault involving the 500kV circuits B560V & B561M be sustained, then action to restore the transfers across the Interconnections to their pre-contingency levels would be counter-productive. This response would result in a higher flow on circuit N582L while there would be an opposing requirement to reduce this flow to within the circuit's long-term emergency rating of 3660A (corresponding to a temperature of 127^{o}C) within a maximum of three hours. Furthermore, in order to re-prepare the system for a possible contingency involving the 500kV circuit N582L, the Negative BLIP flow would need to be reduced to avoid the subsequent overloading of the four 230kV circuits between Longwood TS and Buchanan TS.

The post-contingency transfers across the Interconnections were therefore assumed to remain at their post-contingency levels, with no action taken to restore them to the levels that existed pre-contingency.

With the A1A2 breaker at Stayner TS open and with the transfers across the Interconnections maintained at their post-contingency levels, the studies resulted in the following post-contingency flows with series compensation levels on the 500kV circuits of 50%, 40% & 30%.

Line Upgrade Requirements for Different levels of Series Compensation					
Level of Series Compensation on 500kV Circuits	*500kV Circuit N582L*		*230kV Circuits B4V & B5V*		
	Post-Contingency Flow	***Requirements***	Post-Contingency Flows		***Requirements***
50%	4043A	*Sag Temperature of the 500kV circuit to be increased to 150^{o}C*	*A*	1262A	None: Within the 4km/hr emergency rating
			B	1460A	None: Within the ***15km/hr*** emergency rating
40%	3849A		*A*	1345A	None: Within the 4km/hr emergency rating
			B	1557A	None: Within the ***15km/hr*** emergency rating
30%	3669A	No change required to the Sag Temperature of the 500kV circuit	*A*	1424A	None: Within the 4km/hr emergency rating
			B	***1649A***	*Sag Temperature to be increased to at least 127^{o}C. Flow would then be within the* ***15km/hr*** *long-term emergency rating*

Note:

A refers to the section between Bruce & Hanover TS
[For the existing sag temp of 127^{o}C: 4km/hr long-term emergency rating 1430A}

B refers to the section between Hanover TS & Orangeville TS
[For the existing sag temp of 104^{o}C: 15km/hr long-term emergency rating 1590A]
[For an increased sag temp of 127^{o}C: 15km/hr long-term emergency rating 1830A]

10.7 Effect of Removing All the Local Wind-turbine Generating Facilities from Service

Since a permanent fault involving the 500kV circuits B560V & B561M would require action to reduce the post-contingency flow on the 500kV circuit N582L to within its long-term emergency rating of 3660A, a study was performed to determine the effect that removing all 925MW of wind-turbine generation capacity from service would have on this flow.

For this study, with 50% series compensation, no adjustment was made to the post-contingency transfers across the Interconnections.

The results from the study have been presented in Diagram 17, while those for the pre-contingency condition have already been shown in Diagram 9.

The following Table summarises the pertinent details from the study.

<table>
<tr><td colspan="10">With Seven Bruce Units & 925MW of Wind-turbine Projects
Compensation: 50% & 50%
Primary Demand: 25000MW Negative BLIP Flow: 1464MW</td></tr>
<tr><td rowspan="4">Losses</td><td rowspan="4">Synchronous Condenser Output</td><td colspan="8">Flows</td></tr>
<tr><td colspan="2">500kV Circuit N582L</td><td colspan="4">230kV Circuits B4V/B5V</td><td colspan="2">115kV Circuit S2S</td></tr>
<tr><td>Rating</td><td>4110A</td><td colspan="2">Rating</td><td>A
B</td><td>1430A
1180A</td><td colspan="2">Rating: 770A</td></tr>
<tr><td>MW/MVAr</td><td>Amps</td><td colspan="2">MW/MVAr</td><td colspan="2">Amps</td><td colspan="2">Amps</td></tr>
<tr><td colspan="10">Pre-Contingency Diagram 9</td></tr>
<tr><td rowspan="2">800.0MW</td><td rowspan="2">-36.8MVAr</td><td rowspan="2">1959/ -295</td><td rowspan="2">2098A</td><td>A</td><td>342/ 16</td><td colspan="2">795A</td><td>C</td><td>459A</td></tr>
<tr><td>B</td><td>378/ -69</td><td colspan="2">900A</td><td>D</td><td>687A</td></tr>
<tr><td colspan="10">Post-Contingency With 925MW of Generation Rejected Diagram 17
Circuit S2S Open at Stayner TS
Transfers Across the Interconnections maintained at their Post-contingency Values</td></tr>
<tr><td>1057.5MW</td><td>628.0MVAr</td><td rowspan="2">3313/ -231</td><td rowspan="2">3563A</td><td>A</td><td>511/ 97</td><td colspan="2">1209A</td><td>C</td><td>319A</td></tr>
<tr><td>Δ 257.5MW</td><td>Δ 664.8MVAr</td><td>B</td><td>452/ -122</td><td colspan="2">1146A</td><td>D</td><td>319A</td></tr>
</table>

Note: *A* refers to the section between Bruce and Hanover TS, and
B refers to the section between Hanover TS and Orangeville TS.

C refers to the section between Owen Sound TS and the Blue Mountain Wind Project
D refers to the section between the Blue Mountain Wind Project and Meaford TS

This Table shows that by rejecting all 925MW of wind-turbine generation in the area, in addition to opening breaker A1A2 at Stayner TS, the post-contingency flow on circuit N582L would be reduced to below its long-term emergency rating of 3660A (for a maximum conductor operating temperature of 127^{O}C).

The results also show that the increase in the post-contingency system losses following the rejection of the wind-turbine projects would be approximately 258MW. Consequently, the post-contingency resource deficiency would total approximately 1183MW (925MW + 258MW).

Since this would be within the 30-minute operating reserve of 1350MW, rejecting all of the wind-turbine projects post-contingency would therefore impose no additional operational burden.

10.8 Studies for Different Primary Demands on the System

With the 500kV circuits between the Bruce Complex and Nanticoke GS compensated to 50%, a series of load flow studies were performed for primary system demands in the range of 25000MW to 29000MW.

In these studies, the post-contingency opening of the A1A2 breaker at Stayner TS was **not** represented in order to allow direct comparisons to be made between the results for the respective primary demands. In addition, the post-contingency transfers across the Interconnections were restored to their pre-contingency levels.

The results from these studies have been presented on the following Diagrams, with the more pertinent details summarised in Table 4.

Load Flow Plots with Seven Bruce units & 925MW of wind-turbine generation in-service With 50% / 50% Series Compensation on the existing transmission facilities				
Diagram No.	***Fault Condition***	***Primary Demand***	***Negative-BLIP Flow***	***Detweiler Area Load***
9	Pre-contingency	25000MW	1475MW	1344MW
10	Post-contingency			
18	Pre-contingency	26000MW	1354MW	1406MW
19	Post-contingency			
20	Pre-contingency	27000MW	1233MW	1478MW
21	Post-contingency			
22	Pre-contingency	28000MW	1112MW	1551MW
23	Post-contingency			
24	Pre-contingency	29000MW	992MW	1634MW
25	Post-contingency			

As shown in Table 4, increases in the system primary demand would result in decreases in the Negative BLIP flow and these lower Negative BLIP transfers would also result in reduced post-contingency flows on circuit N582L.

Although the lower post-contingency transfers are shown to result in smaller incremental changes between the pre- and post-contingency system losses and reactive power support requirements, these are more than off-set by the increases in the losses and the reactive support due to the higher loads on the system.

This is particularly noticeable for the reactive power support requirement from the Nanticoke synchronous condensers. For a primary demand of 25000MW, the incremental post-contingency requirement is shown as 1020MVAr, while for a primary demand of 29000MW this falls to 860MVAr. However, the reactive support required pre-contingency for the two primary demands changes from - 40MVAr to + 350MVAr. This means that in order to ensure that the reactive capability of the synchronous condensers remains available for post-contingency support, additional shunt capacitors would need to be installed at Nanticoke GS as the primary demand increases.

TABLE 4	*With Seven Bruce Units + 50% / 50% Series Compensation*									
Diagram No.	*Condition*	*Primary Demand* / *Negative-BLIP Transfer*	*Series Capacitor Voltages*	*Losses*	*Synchronous Condenser Output*	*Flow on 500kV Circuit N582L*		*Flows on230kV Circuits B4V/B5V*		
						Rating	*4110A*	*Rating*		*A* *1430A* / *B* *1180A*
						MW/MVAr	*Amps*		*MW/MVAr*	*Amps*
9.	Pre-cont.	*25000MW*	*BxL:* 550.5kV *NxL:* 554.3kV	800.0MW	-36.8MVAr	1959/ -295	2098A	*A*	342/ 16	795A
								B	378/ -69	900A
10.	Post-cont.	1475MW	*BxL:* 546.0kV *NxL:* 549.1kV	1208.4MW	987.2MVAr	3757/ -180	4072A	*A*	534/ 117	1269A
				Δ 408.4MW	*Δ 1024.0MVAr*			*B*	556/ -126	1414A
18.	Pre-cont.	*26000MW*	*BxL:* 550.5kV *NxL:* 545.5kV	806.6MW	27.6MVAr	1920/ -299	2058A	*A*	345/ 26	804A
								B	379/ -63	907A
19.	Post-cont.	1354MW	*BxL:* 546.7kV *NxL:* 549.8kV	1199.3MW	1004.8MVAr	3677/ -197	3982A	*A*	532/ 122	1267A
				Δ 392.7MW	*Δ 977.2MVAr*			*B*	552/ -120	1408A
20.	Pre-cont.	*27000MW*	*BxL:* 550.6kV *NxL:* 554.6kV	815.1MW	98.0MVAr	1880/ -303	2016A	*A*	349/ 36	815A
								B	380/ -57	915A
21.	Post-cont.	1233MW	*BxL:* 547.2kV *NxL:* 550.2kV	1195.8MW	1074.8MVAr	3597/ -211	3891A	*A*	530/ 129	1266A
				Δ 380.7MW	*Δ 976.8MVAr*			*B*	548/ 114	1403A
22.	Pre-cont.	*28000MW*	*BxL:* 550.5kV *NxL:* 554.5kV	831.7MW	215.6MVAr	1842/ -304	1977A	*A*	353/ 46	827A
								B	381/ 51	924A
23.	Post-cont.	1112MW	*BxL:* 547.5kV *NxL:* 550.5kV	1203.9MW	1160.0MVAr	3516/ -224	3802A	*A*	529/ 134	1267A
				Δ 372.2MW	*Δ 944.4MVAr*			*B*	545/ -111	1399A
24.	Pre-cont.	*29000MW*	*BxL:* 547.5kV *NxL:* 554.0kV	851.6MW	347.6MVAr	1785/ -363	1940A	*A*	359/ 55	844A
								B	385/ -47	938A
25.	Post-cont.	992MW	*BxL:* 544.8kV *NxL:* 550.0kV	1214.3MW	1211.6MVAr	3428/ -287	3732A	*A*	533/ 141	1279A
				Δ 362.7MW	*Δ 864.0MVAr*			*B*	545/ -109	1407A

Note: *A* refers to the section between Bruce and Hanover TS, and
B refers to the section between Hanover TS and Orangeville TS.

The table above shows that for a primary demand of 25000MW, with all of the existing and the planned generating facilities except Lambton GS in-service in south-western Ontario, together with seven Bruce units and all of the new wind-turbine generating facilities operating at their peak output, the transfer across the Negative-BLIP Interface would be close to its operating limit of 1500MW.

As the primary demand increases, the transfers across the Negative-BLIP Interface will therefore decline. At a primary demand of 29000MW, the Negative-BLIP transfer is shown to have declined to just under 1000MW.

Voltages at the Series Capacitor Installations

While the voltages recorded at the series capacitor installations with the transmission facilities compensated to 50% will be lower than those with 60% compensation installed, the reductions as shown in the following Table, will be less pronounced than those recorded for a change from 70% to 60% in the level of compensation.

Voltages Recorded at the Series Capacitor Installations: *with 50% / 50% compensation (25000MW Case)*				
500kV Circuit	*Pre-contingency*		*Post-contingency*	
		Reduction relative to 60% / 60% case		*Reduction relative to 60% / 60% case*
B562L	550.4kV	0.52%	555.8kV	1.71%
B563L	550.5kV	0.52%	546.0kV	1.75%
N582L	554.3kV	0.91%	549.1kV	2.24%

Voltages within the London, Kitchener, Waterloo, Cambridge, Guelph & Orangeville Areas

The following Tables shows the pre- and the post-contingency voltages following a 500kV double-circuit contingency involving circuits B560V & B561M for primary demands of 25000MW and 29000MW, respectively.

Although there is a noticeable reduction (of up to 13kV or 5.5%) in the pre-contingency voltage profiles for the two primary demand levels, this could be addressed through the installation of additional shunt capacitor banks as the area loads increase. The results in the Table also show that the post-contingency voltage declines (with the loads modelled as constant MVA) would not be excessive, with a maximum decline of only 5.5% being recorded. This would be well within the IESO's voltage-decline criterion of 10%.

Voltages in the London, Kitchener, Waterloo, Cambridge, Guelph & Orangeville Area									
	Buchanan TS	Detweiler TS		Orangeville TS	Seaforth TS	Guelph-Campbell TS	Cambridge-Preston TS	Milton TS	*Cambridge-Preston Auto-transformer Transfers*
		230kV	115kV						
Primary Demand: ***25000MW*** *Diagrams 9 & 10* *Net Inflow via the 230kV System into:* *i. London area 1033MW* *ii. Kitchener, Waterloo, Cambridge, Guelph & Orangeville area 1344MW*									
Pre-cont.	241.4kV	244.9kV	125.2kV	246.3kV	241.0kV	240.0kV	240.4kV	526.7kV	49.6MVAr
Post-cont.	233.9kV	232.9kV	120.0kV	232.8kV	227.7kV	227.0kV	229.1kV	520.7kV	134.4MVAr
Change	*-3.1%*	*-4.9%*	*-4.2%*	*-5.5%*	*-5.5%*	*-5.4%*	*-4.7%*	*-1.1%*	

Primary Demand: ***29000MW*** *Net Inflow via the 230kV System into:* *i. London area* *1215MW* *ii. Kitchener, Waterloo, Cambridge, Guelph & Orangeville area* *1634MW*									*Diagrams 24 & 25*
Pre-cont.	236.3kV	235.8kV	121.4kV	238.6kV	232.5kV	229.5kV	227.3kV	524.7kV	195.5MVAr
Post-cont.	230.2kV	225.4kV	116.4kV	228.2kV	219.9kV	218.7kV	218.1kV	518.6kV	244.7MVAr
Change	*-2.6%*	*-4.4%*	*-4.1%*	*-4.4%*	*-5.4%*	*-4.7%*	*-4.0%*	*-1.2%*	

10.10 Other Contingencies

Studies were also performed for the other principal 500kV contingencies that could affect the ability to accommodate the output from the seven Bruce units together with the 925MW of 'committed' wind project in the west and south-west of the Province.

For these studies the 25000MW primary demand case was used, for which the results corresponding to the pre-contingency condition are shown in Diagram 9.

500kV Double-Circuit Contingency involving the Bruce-to-Longwood Line: circuits B562L & B563L

The post-contingency results are shown in Diagram 26.

These show that the losses would increase by only 15MW, primarily as a result of the reduced post-contingency flow on circuit N582L. The reduction in the losses on this circuit therefore off-sets the higher losses on the Bruce-to-Claireville / Milton circuits arising from the increased post-contingency flows into Claireville TS / Milton TS.

Furthermore, except for the post-contingency flows (1111A) on the section of circuits B4V & B5V between the Melancthon projects and Orangeville TS (for which the emergency rating is 1180A), all of the flows remain well within their circuit ratings.

The results also show that because of the reduced transfers through Nanticoke GS the synchronous condensers are collectively absorbing approximately 250MVAr. This amount could be reduced either by cross-tripping one of the shunt capacitors at Nanticoke GS or by retaining all five reactors at Longwood TS in-service post-contingency. (It had been assumed that one of the reactors at Longwood TS would need to be tripped post-contingency to compensate for the loss of the Bruce-to-Longwood circuits)

500kV Single-circuit Contingency involving the Longwood-to-Nanticoke Line: circuit N582L

The post-contingency results are shown in Diagram 27.

While these show that the losses for this contingency would be slightly higher at 61MW, the post-contingency flows on each of the circuits between the Melancthon projects and Orangeville TS would be approximately 25MVA lower; providing further margin between the actual flows and the circuit ratings.

All of the remaining flows are shown to be well within their circuit ratings.

500kV Double-Circuit Contingency involving the line section between Bruce Junction & Willowcreek Junction

While this section is only 15.5km in length, it represents a recognised contingency and therefore the consequences of simultaneously losing one of the Bruce-to-Claireville/Milton circuits with one of the Bruce-to-Longwood circuits has been examined.

The post-contingency results are shown in Diagram 28.

For this contingency condition, the losses increase by a modest 122MW (compared to 408MW for the loss of the Bruce-to-Claireville/Milton circuits).

With all of the reactors at the Bruce Complex and at Longwood TS tripped post-contingency, there is very little decline in the voltage profile from the pre-contingency values. The highest declines occur at Milton TS (~ 4kV) and on the 230kV system originating from the Bruce Complex (~ 4kV). Furthermore, only 110MVAr of reactive support is shown to be required from the synchronous condensers at Nanticoke GS.

All of the post-contingency flows except for those on the section of circuits B4V & B5V between the Melancthon projects and Orangeville TS (1129A) remain well within their circuit ratings.

11. Re-Preparation of the System with 7 Bruce Units & 925MW of Wind-Turbine Generation In-Service

For the condition with the 500kV circuits compensated to 50%, the analysis has shown that following the loss of the Bruce-to-Claireville/Milton circuits with seven Bruce units in-service together with the wind-turbine generation, the flows on the 500kV Longwood-to-Nanticoke and the 230kV Bruce-to-Orangeville circuits are expected to be close to their thermal limits.

In response to a subsequent contingency involving the 500kV circuit N582L, all of the wind projects together with two Bruce units would need to be rejected to ensure that transient stability (with margin) can be maintained.

Since there is also a requirement to reduce the transfers on the 500kV circuit to below its long-term emergency rating of 3660A within a maximum period of three hours, then during the 30-minute re-preparation period following a sustained outage of the Bruce-to-Claireville/Milton circuits, either of the following actions (or a combination of them) would need to be taken:

- Remove all of the wind-turbine generating facilities from service
- Reduce the transfers across the Ontario-Michigan Interface

Diagram 17 from Section 10.7 of this Report showed the situation that would exist at the end of the re-preparation period with all 925MW of the wind-turbine projects out-of-service.

Diagram 29 shows the corresponding situation with an equivalent reduction of 925MW in the transfers across the Ontario-Michigan Interface.

The resulting flows on the critical transmission facilities of these two responses are summarised in the following Table:

Comparison of the Re-Preparation Responses									
Primary Demand: 25000MW			*No. of Bruce Units: 7*			*Negative BLIP Flow: 1476MW*			
Compensation: 50% & 50%									
Losses	*Synchronous Condenser Output*	*500kV Circuit N582L*		*Flows on B4V/B5V*				*Flows on S2S*	
		Rating	*4110A*	Rating		*A*	*1430A*	*Rating: 770A*	
						B	*1180A*		
		MW/MVAr	*Amps*	*MW/MVAr*		*Amps*		*Amps*	
Immediately Post-contingency Following the Loss of the 500kV Circuits B560V & B561M — Diagram 12; 115kV Circuit S2S opened at Stayner TS; No adjustment of the post-contingency transfers across the Interconnections.									
1188.4MW	983.2MVAr	3730/ -186	4043A	*A*	530/ 119	1262A		*C*	81A
				B	573/ -136	1460A		*D*	317A
Response 1: All 925MW of Wind-turbine Projects Removed from Service — Diagram 17									
1057.5MW	628.0MVAr	3313/231	3563A	*A*	512/ 97	1209A		*C*	319A
				B	452/ -122	1146A		*D*	319A
Response 2: Transfers Across the Ontario-Michigan Interface Reduced by 925MW — Diagram 29									
1021.4MW	513.2MVAr	3256/ 223	3482A	*A*	506/ 89	1193A		*C*	79A
				B	550/ 136	1375		*D*	316A

Note: *A* refers to the section between Bruce and Hanover TS, and
B refers to the section between Hanover TS and Orangeville TS.

C refers to the section between Owen Sound TS and the Blue Mountain Wind Project
D refers to the section between the Blue Mountain Wind Project and Meaford TS

These results show that reducing the transfers across the Ontario-Michigan Interface would have the greater impact on the flow on circuit N582L, while removing the wind-turbine generators from service would result in a more pronounced reduction in the flows on circuits B4V & B5V.

Consequently, a combination of measures to reduce not only the transfers across the Ontario-Michigan Interface but also to remove from service those wind-turbine projects that are directly connected to circuits B4V & B5V, would appear to offer the greatest benefit. However, these measures, together with accounting for the increased system losses, would need to represent a reduction in resources that would not exceed the 30-minute operating reserve of 1350MW.

Diagram 30 shows the results for the condition with the two Leader Wind and the two Melancthon Wind Projects removed from service and with the transfers from the Ontario-New York Interface reduced to their pre-contingency level of 1400MW. In addition the transfers across the Ontario-Michigan Interface have been reduced by a further 535MW, from 1310MW to 773MW.

For this condition the system losses are shown to total 1020MW, representing a net increase of 220MW over the pre-contingency losses.

Implementing these changes would result in a net reduction in available resources totalling approximately 1345MW, as detailed below:

Reduction in the transfers across the Ontario-New York Interface	190MW
Reduction in the transfers across the Ontario-Michigan Interface	535MW
Removal from service of the wind-turbine projects connected to circuits B4V & B5V	400MW
Increase in transmission losses	220MW
Total	*1345MW*

The resulting flows on the critical transmission facilities are summarised in the following Table:

<table>
<tr><td colspan="9">Primary Demand: 25000MW   No. of Bruce Units: 7   Negative BLIP Flow: 1476MW
Compensation: 50% & 50%</td></tr>
<tr><td rowspan="4">Losses</td><td rowspan="4">Synchronous Condenser Output</td><td colspan="2">500kV Circuit N582L</td><td colspan="3">Flows on B4V/B5V</td><td colspan="2">Flows on S2S</td></tr>
<tr><td rowspan="2">Rating</td><td rowspan="2">4110A</td><td rowspan="2">Rating</td><td>A</td><td>1430A</td><td colspan="2" rowspan="2">Rating: 770A</td></tr>
<tr><td>B</td><td>1180A</td></tr>
<tr><td>MW/MVAr</td><td>Amps</td><td>MW/MVAr</td><td colspan="2">Amps</td><td colspan="2">Amps</td></tr>
<tr><td colspan="9">Response 1:   All 925MW of Wind-turbine Projects Removed from Service   Diagram 30</td></tr>
<tr><td rowspan="2">1019.8MW</td><td rowspan="2">516.4MVAr</td><td rowspan="2">3303/ -207</td><td rowspan="2">3537A</td><td>A</td><td>513/ 91</td><td>1210A</td><td>C</td><td>79A</td></tr>
<tr><td>B</td><td>461/ -134</td><td>1164A</td><td>D</td><td>316A</td></tr>
</table>

Note: *A* refers to the section between Bruce and Hanover TS, and
B refers to the section between Hanover TS and Orangeville TS.

C refers to the section between Owen Sound TS and the Blue Mountain Wind Project
D refers to the section between the Blue Mountain Wind Project and Meaford TS

These results show that the proposed combination involving the removal from service of selected wind-turbine projects together with the reduction of transfers across the Ontario-Michigan and Ontario-New York Interfaces would meet the requirement of respecting the long-term emergency ratings of circuits N582L and B4V & B5V.

500kV Single-Circuit Contingency on N582L

Analysis has indicated that the loss of the 500kV circuit N582L when circuits B560V & B561M are already out-of-service would result in a reduction of approximately 45% in the transfers across the Ontario-Michigan Interface. A corresponding increase would occur in the transfers across the Ontario-New York Interface.

For the Re-preparation Condition shown in Diagram 30 which has transfers of 773MW across the Ontario-Michigan Interface, a contingency involving circuit N582L would be expected to reduce them by approximately 350MW to 425MW.

Diagram 31 shows the post-contingency results following a single-circuit contingency involving circuit N582L. In response to this contingency two Bruce B units were also rejected, together with all the wind-turbine projects.

For this study, it was assumed that the resulting resource deficiency would be supplied from existing Ontario generating capacity, although in practice it would be expected to be addressed through a combination of increased output from internal generating facilities as well as load rejection.

The corresponding flows on the critical 230kV circuits are shown in the following Table:

With Seven Bruce Units & 925MW of Wind-turbine Projects *Primary Demand: 25000MW*						***Compensation: 50% & 50%***		
Losses	*Flows*							
	230kV Circuits B4V/B5V		*230kV Circuits B22D/B23D*		*230kV Circuits W42L/W43L*		*230kV Circuits W44LC/W45LC*	
	Rating	*1430A*	*Rating*	*1400A*	Rating	*1400A*	Rating	*1460A*
	MW/MVAr	*Amps*	*MW/MVAr*	*Amps*	*MW/MVAr*	*Amps*	*MW/MVAr*	*Amps*
Post-Contingency - *Following the loss of* **circuit N582L** *& the* **rejection** *of Two Bruce Units & the remaining Wind-turbine Projects* ***Ontario-Michigan Transfers reduced to ~ 425MW***						*Diagram 31* **Negative** *BLIP Flow: 207MW*		
816.4MW	563MW 122MVAr	1337A	420MW 91MVAr	1000A	544MW 132MVAr	1305A	645MW 114MVAr	**1563A**

These results show that even with two Bruce units and the remaining wind-turbine projects rejected, overloading of the 230kV circuits W44LC & W45LC, between Longwood TS and Buchanan TS, would occur following the loss of the 500kV circuit N582L.

Reducing the transfers over the Negative BLIP Interface either through reduced transfers across the Ontario-Michigan Interface or through the rejection of generating capacity in the Sarnia-Windsor area would limit the flows on the 230kV circuits between Longwood TS and Buchanan TS.

The results of a study with the Ontario-Michigan transfers reduced to approximately zero are summarised in Diagram 32 and the corresponding flows on the critical 230kV circuits are shown in the following Table:

With Seven Bruce Units & 925MW of Wind-turbine Projects *Primary Demand: 25000MW*						***Compensation: 50% & 50%***		
Losses	*Flows*							
	230kV Circuits B4V/B5V		*230kV Circuits B22D/B23D*		*230kV Circuits W42L/W43L*		*230kV Circuits W44LC/W45LC*	
	Rating	*1430A*	*Rating*	*1400A*	Rating	*1400A*	Rating	*1460A*
	MW/MVAr	*Amps*	*MW/MVAr*	*Amps*	*MW/MVAr*	*Amps*	*MW/MVAr*	*Amps*
Post-Contingency - *Following the loss of* **circuit N582L** *& the* **rejection** *of Two Bruce Units & the remaining Wind-turbine Projects* ***Ontario-Michigan Transfers reduced to ~ 0MW***						*Diagram 32* **Positive** *BLIP Flow: 192MW*		
757.6MW	531MW 94MVAr	1252A	403MW 73MVAr	952A	509MW 88MVAr	1207A	589MW 75MVAr	1411A

The results in the Table above show that rejecting two Bruce B units together with all the remaining wind-turbine projects, as well as reducing the transfers across the Ontario-Michigan Interface to approximately zero, would allow the post-contingency flows on all the 230kV circuits to be maintained within their long-term emergency ratings following a contingency involving the 500kV circuit N582L.

Resulting Resource Deficiency

The resulting resource deficiency from both the re-preparation activities and the subsequent immediate response to a contingency involving the 500kV circuit N582L following a sustained outage of circuits B560V & B561M, would therefore be as follows:

• Rejection of all of the wind-turbine projects in the area		925MW
• Rejection of two of the Bruce B generating units		1640MW
• Reduction of the transfers on the Ontario-Michigan Interface to zero [1500MW less the automatic 350MW reduction following the N582L contingency]		1150MW
• Change in transmission system losses		-50MW
	Accumulated Deficiency	*3665MW*
• Normal 30-minute Operating Reserve		1350MW
	Difference	*2315MW*

To address the resulting 2300MW resource deficiency, a combination of increased output from the Ontario generating resources that remain available and load rejection would therefore be required.

Carrying a higher operating reserve than the minimum required by NPCC would reduce the amount of load that would need to be rejected, however it would impose a significant financial burden for what is considered to be a higher unlikely event.

In addition, although the existing Bruce Special Protection System has the capability to reject load in response to certain contingencies, circuit N582L is presently not one of them. Modification of the SPS would therefore be required so that load and generation rejection could be initiated for the loss of this circuit.

12. Load Flow Analysis: With Eight Bruce Units In-service

12.1 With the Existing Transmission Facilities & No Wind-Turbine Generation

Studies were performed for the condition with all eight Bruce units in-service and with no new wind-turbine generating facilities in-service (essentially corresponding to the situation prior to the shut-down of the Bruce A station in 1998).

The intent was to determine whether the existing transmission facilities with series capacitors installed, would be adequate to allow all eight Bruce units to remain in-service post-contingency, with no overloading of the transmission system.

Diagrams 33 & 34 show the pre- and post-contingency results following the loss of circuits B560V & B561M due to a 500kV double-circuit contingency.

In these studies, although lower levels of compensation would have satisfied the requirements for transient stability, it was found to be necessary to compensate the Bruce-to-Longwood circuits and the Longwood-to-Nanticoke circuit to **50%** to minimise the post-contingency overloading of the 230kV circuits between the Bruce Complex and Orangeville TS.

The resulting flows on the critical transmission circuits are summarised in the following Table:

<table>
<tr><td colspan="8">With Eight Bruce Units & No Wind-turbine Projects Compensation: 50% & 50%
Primary Demand: 25000MW Negative BLIP Flow: 1277MW</td></tr>
<tr><td rowspan="4">Losses</td><td rowspan="4">Synchronous Condenser Output</td><td colspan="2">500kV Circuit N582L</td><td colspan="3">Flows on B4V/B5V</td><td>Flows on S2S</td></tr>
<tr><td rowspan="2">Rating</td><td rowspan="2">4110A</td><td rowspan="2">Rating</td><td>A</td><td>1430A</td><td rowspan="2">Rating: 770A</td></tr>
<tr><td>B</td><td>1180A</td></tr>
<tr><td>MW/MVAr</td><td>Amps</td><td colspan="2">MW/MVAr</td><td>Amps</td><td>Amps</td></tr>
<tr><td colspan="8">Pre-contingency Diagram 33</td></tr>
<tr><td rowspan="2">812.7MW</td><td rowspan="2">-29.6MVAr</td><td rowspan="2">1936/ -297</td><td rowspan="2">2074A</td><td>A</td><td>364/ 24</td><td>848A</td><td rowspan="2">608A</td></tr>
<tr><td>B</td><td>299/ -69</td><td>722A</td></tr>
<tr><td colspan="8">Post-contingency: Following the loss of the 500kV circuits B560V & B561M
115kV Circuit S2S Open at Stayner TS
No Restoration of the O-M & O-NY Transfers to their Pre-contingency Levels Diagram 34</td></tr>
<tr><td>1215.6MW</td><td>994MVAr</td><td rowspan="2">3728/ -214</td><td rowspan="2">4057A</td><td>A</td><td>557/ 128</td><td>1327A</td><td rowspan="2">595A</td></tr>
<tr><td>Δ 402.9MW</td><td>Δ 1023.6MVAr</td><td>B</td><td>495/ -143</td><td>1280A</td></tr>
</table>

Note: *A* refers to the section between Bruce and Hanover TS, and
B refers to the section between Hanover TS and Orangeville TS.

Since the condition examined assumed that there were no wind-turbine projects in-service, it would therefore be inappropriate to use the higher rating corresponding to a wind-speed of 15km/hr for determining the ratings of the circuits.

The results therefore show that following a contingency involving the 500kV circuits B560V & B561M the section of circuits B4V & B5V between Hanover TS and Orangeville TS would be overloaded. Reducing the level of series compensation on the 500kV circuits would increase the post-contingency flows on circuits B4V & B5V, thereby aggravating the extent of the overloading. To address this situation, either the maximum conductor operating temperature of the critical section of circuits B4V & B5V would need to be increased beyond its present value of 104^{O}C or the level of series compensation would need to be increased above the 50% level considered in these studies. However any increase in the level of compensation would need to be limited to ensure that the post-contingency flow on circuit N582L does not exceed its enhanced rating of 4110A.

It would therefore appear that, in the absence of any wind-turbine projects and with series compensation at a level of approximately 50% installed on the 500kV circuits, the existing transmission facilities would be marginally adequate to accommodate all eight Bruce units without having to employ post-contingency generation rejection.

Furthermore to accommodate all eight Bruce units in addition to all of the wind-turbine projects that have been awarded contracts under the Renewables I & II RFPs, it has been concluded that additional transmission facilities will be necessary if generation rejection in response to a first contingency is to be avoided.

12.2 *Load Flow Analysis: With Eight Bruce Units In-service & 925MW of Wind-Turbine Generation together with additional Transmission Facilities*

For the purpose of this assessment, two distinct alternatives for new 500kV transmission reinforcement have been assumed:

- *Alternative 1: A new 500kV single-circuit line between Longwood TS and Middleport TS.*

  Notionally, the route for the new line has been assumed to follow the existing right-of-way between Longwood TS and Buchanan TS and then to replace the 230kV circuit M31W between Buchanan TS and Middleport TS. Based on this route, the length of the new line has been estimated at approximately 150km.

  Since the transient stability studies have indicated that series capacitors would be required in this new single-circuit line it was also assumed that they would be installed where the new line by-passes Buchanan TS, approximately 52km from Longwood TS.

- *Alternative 2: A new 500kV double-circuit line between the Bruce Complex and either Milton TS or Essa TS.*

  If the new line were to terminate at Milton TS, then it was assumed that it would follow the right-of-way of the existing 500kV double-circuit line and would have a similar length of approximately 176km.

  If the new line were to terminate at Essa TS then it was assumed that it would follow the same right-of-way as the existing 500kV double-circuit line but continue along the right-of-way of the existing 230kV line B4V & B5V into Orangeville TS. It was then assumed to follow the right-of-way of the existing 230kV line E8V & E9V into Essa TS. If it were to follow this route, then the length of the new line would be approximately 182km.

  Regardless of where the new double-circuit line would be terminated, it was assumed that one of the circuits would originate from the Bruce A 500kV switchyard while the other would originate from the Bruce B switchyard.

  With a new 500kV double-circuit line between the Bruce Complex and either Milton TS or Essa TS there would be no requirement for series compensation to be installed on any of the 500kV transmission facilities to maintain post-contingency transient stability.

Load Flow studies were performed for both reinforcement alternatives, using the 25000MW primary demand case so as to obtain the highest Negative-BLIP transfers.

12.2.1 *Alternative 1: With a new 500kV single-circuit line between Longwood TS and Middleport TS*
(Approximate length of the new line: 150km)

Although the following minimum levels of series compensation would be required to ensure post-contingency transient stability, they were found to result in overloading of the 230kV circuits B4V & B5V, between the Bruce Complex and Orangeville TS, following a 500kV double-circuit contingency involving circuits B560V & B561M:

- Bruce-to-Longwood 500kV circuits B562L & B563L 20%
- Longwood-to-Nanticoke 500kV circuit N582L 10%
- Longwood-to-Middleport new 500kV circuit 10%

Studies were therefore performed with all of the 500kV circuits listed above compensated to 40% to increase the post-contingency transfers through those circuits.

The results have been presented in Diagrams 35 & 36 for the pre- and post-contingency conditions, respectively.

The critical flows have been summarised in the Table below:

With Eight Bruce Units + 925MW of wind-turbine generation

With a new 500kV Single-Circuit Line: Longwood TS-to-Middleport TS

With 40% / 40% Series Compensation, including 40% compensation of the new 500kV circuit

Negative-BLIP Flow: 1485MW

Losses	*Synchronous Condenser Output*	*Flows*					
		500kV Circuits			*230kV Circuits B4V/B5V*		
		Rating	*3660A 4110A (N582L)*		*Rating*	*A*	*1430A*
						B	*1180A*
			MW/MVAr	*Amps*		*MW/MVAr*	*Amps*
Pre-Contingency							*Diagram 35*
825.7MW	-101.6MVAr	B562L	1030/ -133	1100A	*A*	354/ 21	824A
		B563L	1054/ -125	1122A			
		N582L	1308/ -245	1410A	*B*	390/ -72	932A
		New	1373/ -177	1468A			
Post-Contingency: Following the loss of the 500kV circuits B560V & B561M 115kV Circuit S2S Open at Stayner TS Transfers Across the O-M & O-NY Interfaces Restored to their Pre-Contingency Levels							*Diagram 36*
1217.7MW	842.0MVAr	B562L	2356/ -313	2535A	*A*	539/ 124	1284A
		B563L	2383/ -313	2558A			
		N582L	2362/ -315	2609A	*B*	581/ -141	1487A
Δ 392.0MW	*Δ 943.6MVAr*	New	2554/ -119	2798A			

Note: *A* refers to the section between Bruce and Hanover TS, and
B refers to the section between Hanover TS and Orangeville TS.

These results show that while the parallelling of the existing 500kV circuit N582L with a new 500kV circuit to Middleport TS would avoid the post-contingency overloading of circuit N582L, the minimum level of compensation that would need to be installed on the 500kV circuits would be 40% so as to limit the post-contingency flows through the 230kV circuits B4V & B5V.

With this level of compensation installed, the post-contingency flows on the section of the 230kV circuits B4V & B5V between the Melancthon Projects and Orangeville TS would be within their long-term emergency rating of 1590A based on a wind speed of **15km/hr**.

The results also show that even with the new line installed and with the 500kV facilities compensated to 40%, approximately 940MVAr of reactive support would still be required from the synchronous condensers at Nanticoke GS to maintain an acceptable post-contingency voltage profile.

It should also be noted that the post-contingency system losses would also increase of approximately 390MW.

12.2.2 Alternative 2.1: With a new 500kV double-circuit line between the Bruce Complex and Milton TS
(Approximately length of the new line: 176km)

The results have been presented in Diagrams 37 & 38 for the pre- and post-contingency conditions, respectively.

The critical flows have been summarised in the Table below:

With Eight Bruce Units + 925MW of wind-turbine generation
With a new 500kV Double-Circuit Line: Bruce-to-Milton TS
With No Series Compensation
Negative BLIP Flow: 1481MW

Losses	*Synchronous Condenser Output*	*Flows*					
		500kV Circuits			*230kV Circuits B4V/B5V*		
		Rating	*3660A 4110A (N582L)*		*Rating*	*A*	*1430A*
						B	*1180A*
			MW/MVAr	*Amps*		*MW/MVAr*	*Amps*
Pre-Contingency							*Diagram 37*
741.2MW	-63.2MVAr	BxL:	310/ -25	330A	*A*	315/ 1	730A
		NxL:	1046/ -136	1115A			
		BxM (Existing):	1274/ 42	1349A	*B*	352/ -70	831A
		BxM (new):	1231/ 35	1304A			
*Post-Contingency: Following the loss of the 500kV circuits B560V & B561M 115kV Circuit S2S **OPEN** at Stayner TS Transfers Across the O-M & O-NY Interfaces Restored to their Pre-Contingency Levels*							*Diagram 38*
861.1MW	159.6MVAr	BxL:	655/ -227	743A	*A*	400/ 39	933A
		NxL:	1511/ 34	1564A			
		BxM (Existing):	-	-	*B*	446/ -92	1081A
Δ 119.9MW	*Δ 222.8MVAr*	BxM (new):	2019/ 240	2180A			

Note: *A* refers to the section between Bruce and Hanover TS, and
B refers to the section between Hanover TS and Orangeville TS.

For this contingency condition, post-contingency tripping of the A1A2 breaker at Stayner TS was still found to be necessary to avoid overloading the 115kV circuit S2S.

With circuit S2S open and the transfers on the Interconnections restored to their pre-contingency levels, all of the monitored post-contingency flows are shown to remain within the 4km/hr wind-speed ratings for the circuits.

In addition, the presence of the new 500kV double-circuit line is shown to limit the increase in the post-contingency system losses to 120MW while the reactive power requirements from the synchronous condensers at Nanticoke GS is limited to approximately 220MVAr. This would be within the capability of one of the existing generating units at Nanticoke GS, converted to synchronous condenser operation.

12.2.3 Alternative 2.2: With a new 500kV double-circuit line between the Bruce Complex and Essa TS

(Approximate length of the new line: 182km)

The results have been presented in Diagrams 39 & 40 for the pre- and post-contingency conditions, respectively.

The critical flows have been summarised in the Table below:

With Eight Bruce Units + 925MW of wind-turbine generation
With a new 500kV Double-Circuit Line: Bruce-to-Essa TS
With No Series Compensation
Negative BLIP Flow: 1481MW

Losses	*Synchronous Condenser Output*	*Flows*					
		500kV Circuits			*230kV Circuits B4V/B5V*		
		Rating	*3660A 4110A (N582L)*		*Rating*	*A: 1430A*	*B: 1180A*
			MW/MVAr	*Amps*		*MW/MVAr*	*Amps*
Pre-Contingency							*Diagram 39*
747.8MW	-14.8MVAr	BxL:	345/ -21	366A	*A*	293/ 1	681A
		NxL:	1114/ -131	1186A			
		BxM:	1480/ 99	1569A	*B*	332/ -60	782A
		BxE (new):	1101/ 45	1168A			
		ExV:	934/ 94	1009A			
Post-Contingency: Following the loss of the 500kV circuits B560V & B561M 115kV Circuit S2S **CLOSED** *at Stayner TS Transfers Across the O-M & O-NY Interfaces Restored to their Pre-Contingency Levels*							*Diagram 40*
906.9MW	256.8MVAr	BxL:	799/ -188	879A	*A*	388/ 44	906A
		NxL:	1724/ 37	1799A			
		BxM:	-	-	*B*	423/ -72	1026A
		BxE (new):	1839/ 189	1981A			
Δ 159.1MW	*Δ 271.6MVAr*	ExV	1675/ -94	1849A			

Note: *A* refers to the section between Bruce and Hanover TS, and
B refers to the section between Hanover TS and Orangeville TS.

For this contingency condition, since the post-contingency flow on the section of circuit S2S between the Blue Mountain Wind Project and Meaford TS was 733A and therefore within its long-term emergency rating of 770A, post-contingency tripping of the A1A2 breaker at Stayner TS was therefore unnecessary.

While the performance of this arrangement with the proposed 500kV double-circuit line terminated at Essa TS is shown to be similar to that with the new line terminated at Milton TS, it would result in increased transfers over the two 500kV circuits between Essa TS and Claireville TS.

For the case that was studied with a primary demand of 25000MW and without a new 500kV double-circuit line, the combined flow on circuits E510V & E511V between Essa TS and Claireville TS was approximately 40MW.

However, as shown in Figure 1, the transfers over the 500kV circuits E510V & E511V during July & August of last year (which was a very dry year and therefore had an adverse effect on the output from the hydroelectric plants) frequently exceeded 1000MW.

With the new line terminated at Essa TS, the combined flows on these circuits are shown to increase to approximately 1860MW pre-contingency and 3340MW post-contingency. Consequently, superimposing an additional flow of 1000MW on the combined 3340MW post-contingency flow on these circuits would therefore result in their combined rating of approximately 3800MVA (1898MVA per circuit from Table 1) being exceeded.

If the new 500kV double-circuit line were to terminate at Essa TS then remedial measures would need to be taken to raise the operating temperatures of the two existing Essa-to-Claireville 500kV lines. Since Figure 1 shows flows of up to 1400MW, the ratings of each of these circuits would need to be increased to at least 2400MW (2600MVA at 0.9 power factor).

[Although not examined as part of this assessment, the contingency condition involving either circuit E510V or E511V may be more limiting and would need to be considered.]

Comparison of the two Alternatives for new transmission reinforcement

Alternative 1, with a new 500kV single-circuit line installed between Longwood TS and Middleport TS would be substantially inferior to Alternative 2 involving a new 500kV double-circuit line between the Bruce Complex and either Milton TS or Essa TS, for the following reasons:

- It would require the 500kV circuits between the Bruce Complex and Longwood TS, and between Longwood and Nanticoke SS/Middleport TS, to be series compensated to 40%.

  For Alternative 2, none of the 500kV circuits would need to have series compensation.

- It would require higher levels of post-contingency reactive support to be provided from the synchronous condensers at Nanticoke GS.

  Approximately 950MVAr of support would need to be available, whereas Alternative 2 would require a maximum of approximately 275MVAr.

- It would result in additional post-contingency losses of approximately 400MW, while for Alternative 2 the increased losses would be approximately 160MW.

- It would also present similar challenges with respect to re-preparing the system for a subsequent contingency to those discussed previously in Section 11 for the existing system arrangement.

  Since Alternative 2 would provide an additional, independent path from the Bruce Complex, a sustained outage involving circuits B560V & B561M would result in the system appearing similar to today's arrangement. For this, the consequences of a single element contingency would be much less severe.

- It would also present significantly less scope for the incorporation for future generation projects.

The performance of the two options for terminating the new 500kV double-circuit line proposed under Alternative 2 have been shown to be similar, except that if the line were to terminate at Essa TS it would require remedial work on the two existing 500kV single-circuit lines between Essa TS and Claireville TS. This work would involve raising their operating temperature from the present 78^{o}C so as to increase their long-term emergency ratings to at least 2600MVA.

Furthermore, should the new line terminate at Essa TS rather than at Milton TS it would result in an additional 40MW of post-contingency losses and a requirement for an additional 50MVAr of post-contingency reactive support from the Nanticoke synchronous condensers. However, since these increases are not especially large and since they would only occur following a double-circuit contingency, they would not be sufficient to influence any decision on the termination point for the new line.

13. Synchronous Condensers

The results presented in Sections 10.3 to 10.5 for the condition with seven Bruce units and 925MW of wind-turbine generation capacity in-service, and with series capacitors installed on the existing 500kV transmission facilities, that the post-contingency reactive support required from the synchronous condensers at Nanticoke GS totals:

- approximately 1020MVAr with 50% series compensation installed, and
- approximately 1125MVAr with 30% series compensation installed

The 1125MVAr of reactive support could be provided through the conversion of at least three of the existing generating units at Nanticoke GS to synchronous condenser operation.

However, to ensure that adequate capacity remains available while units are being maintained or are forced out of service due to faults, the IESO is recommending that four units be converted.

If a new 500kV line were to be constructed to Milton TS or Essa TS, then the reactive support requirement from Nanticoke GS would fall to approximately 275MVAr. This would be within the capability of a single synchronous condenser, or a maximum of two units if redundancy is to be provided.

The IESO is therefore recommending that the feasibility of installing Static VAr Compensators (SVCs) to provide a portion of the reactive power requirements, be examined. This could allow only one, or possibly two, of the Nanticoke units to be converted to synchronous condenser operation. Furthermore, if the SVCs were to be of a relocatable design this would be an additional benefit, allowing them to be installed at other locations on the system once the new line is placed in-service.

14. Bruce Special Protection System (SPS)

With seven Bruce units in-service together with all of the committed wind-turbine projects, the Bruce Special Protection System will need to be enhanced so that it can react to the following contingency conditions and provide the appropriate responses:

Additional contingency conditions that need to be addressed by the Bruce SPS

- 500kV circuit N582L
- 230kV circuits B4V & B5V: both single- and double-circuit contingencies
- 230kV circuits B22D & B23D: both single- and double-circuit contingencies

Additional responses that need to be included in the Bruce SPS

- Cross-tripping of the 115kV breaker A1A2 at Stayner TS
- Generation rejection for the individual wind-turbine projects (or selected groups of projects)
- Switching of the new shunt capacitor banks
- Additional load rejection selections (if the amount provided through the present selections is insufficient)

  The intent of providing post-contingency switching of the shunt capacitor banks is to address those situations, particularly under light load conditions, where switching of the capacitor banks into service pre-contingency would result in excessively high voltages.

15. Independent Phase Controlled Compensators at Tillsonburg TS & Norfolk TS

When the 500kV circuit N582L was constructed between Longwood TS and Nanticoke SS, sections of the 115kV circuits that supply Norfolk TS and Tillsonburg TS were installed on the same structures. It was expected that this could result in excessive voltage imbalances on these 115kV circuits whenever the 500kV circuit N582L was subjected to high power flows, particularly under fault conditions.

Separate schemes, called Independent Phase Controlled Compensators, were therefore installed at both Norfolk TS and Tillsonburg TS to automatically switch capacitor banks into and out-of-service across the appropriate phases of the respective 27.6kV busbars whenever excessive voltage imbalances were detected.

With the introduction of series capacitors into the 500kV path between the Bruce Complex and Nanticoke SS, via Longwood TS, the pre- and post-contingency flows are expected to increase beyond those that were assumed in the original design of the two schemes.

It is therefore recommended that the capability of the existing Independent Phase Controlled Compensators be reviewed to determine whether they will have adequate capacity for the projected duties once the series capacitors have been installed.

16. Conclusions & Recommendations

16.1 Conclusions

The principal conclusions from this assessment are as follows:

- To ensure adequate post-contingency voltages in the Kitchener, Waterloo, Cambridge, Guelph and Orangeville areas following the loss of the 500kV Bruce to Claireville TS / Milton TS circuits, the following facilities will need to be installed:
    - A 250MVAr 230kV shunt capacitor bank at both Detweiler TS and at Orangeville TS
    - A 230/115kV auto-transformer at Cambridge-Preston TS to interconnect the 230kV and 115kV systems in the immediate vicinity.

1. ***With no new transmission facilities and seven Bruce units plus 925MW of wind-turbine generation***.

    The following conclusions assume that in the event of a sustained outage involving the 500kV circuits B560V & B561M, the post-contingency transfers across the Ontario-Michigan Interface would not be returned to their pre-contingency levels since this would be counter-productive to re-preparing the system for a subsequent contingency. However, it has been assumed that the transfers across the Ontario-New York Interface would be reduced to return them to their pre-contingency levels.

- To maintain post-contingency transient stability, the 500kV circuits between the Bruce Complex and Longwood TS and between Longwood TS and Nanticoke SS would need to be compensated to at least **20%.**

- To avoid post-contingency overloading of the 115kV circuit S2S between Owen Sound TS and Orangeville TS, cross-tripping of the A1A2 breaker at Stayner TS would need to be initiated following a double-circuit contingency involving the 500kV circuits B560V & B561M.

- With the 500kV circuits between the Bruce Complex and Longwood TS and between Longwood TS and Nanticoke SS compensated to either **40% or 50%**, the post-contingency flows on the 230kV circuits B4V & B5V between the Bruce Complex and Orangeville TS would be within their *15km/hr* wind-speed ratings.

However, for these levels of series compensation, the existing 500kV circuit N582L between Longwood TS and Nanticoke GS would need to be uprated so that ground clearances would be adequate to allow the conductors to be operated at temperatures up to the maximum of 150^{o}C. This would provide an enhanced rating of 4110A.

- With the 500kV circuits between the Bruce Complex and Longwood TS and between Longwood TS and Nanticoke SS compensated to **30%,** the post-contingency flow on circuit N582L would be just marginally over its long-term rating of 3660A and would therefore not require this circuit to be uprated.

  However, the lower level of compensation on the 500kV circuits would result in higher post-contingency flows on the 230kV circuits B4V & B5V that would exceed their 15km/hr wind-speed rating of 1590A.

  To accommodate these higher flows, the maximum conductor operating temperature for the section of circuits B4V & B5V between Hanover TS and Orangeville TS would need to be increased above its present value of 104^{o}C. Raising the operating temperature to 127^{O}C would result in a 15km/hr wind-speed rating of 1830A which would be more than adequate for the projected post-contingency flow of 1650A.

- In the event of a sustained outage involving the 500kV circuits B560V & B561M, the preferred course of action for re-preparing the system for a subsequent contingency would involve the removal from service of the wind-turbine projects connected to the 230kV circuits B4V & B5V, together with reducing the transfers across the Ontario-Michigan Interface. This would be additional to the return of the transfers across the Ontario-New York Interface to their pre-contingency levels.

  The cumulative net effect of these actions on the available system resources would need to be limited to approximately 1350MW, to remain within the 30-minute operating reserve for the system.

  In addition to these changes, the Bruce SPS would need to be armed so that it can respond to whatever contingency may subsequently occur. For the most-onerous contingency, which would involve the loss of the 500kV circuit N582L, two Bruce B units together with all the remaining wind-turbine projects in the area would need to be armed for automatic rejection. In addition, arming would be required to initiate the rejection of sufficient load to reduce the post-contingency transfers across the Ontario-Michigan Interface to zero.

  Although these responses were determined for the condition with the 500kV circuits compensated to a level of 50%, the requirements for lower levels of compensation are expected to be similar.

- With the 500kV circuits between the Bruce Complex and Longwood TS and between Longwood TS and Nanticoke SS compensated to **50%**, all eight Bruce units could be incorporated without any of the wind-turbine projects. However, the 500kV circuit N582L would need uprating to provide an enhanced rating of 4110A so that the post-contingency flow would remain within its rating. In addition, since this condition assumed that there were no wind-turbine projects incorporated it would therefore be inappropriate to use a wind-speed rating of 15km/hr. Consequently, to respect the 4km/hr wind-speed rating of the 230kV circuits B4V & B5V they would also need to be uprated.

- To incorporate all eight Bruce units as well as the 925MW of wind-turbine generation capacity for which contracts have been awarded without having to employ post-contingency generation rejection in response to a first contingency, additional transmission facilities will need to be constructed.

2. With new 500kV Transmission Facilities

The Assessment examined two Alternatives for reinforcing the transmission system to allow all eight Bruce units together with the committed wind-turbine projects to be incorporated without the need to employ post-contingency generation rejection.

Alternative 1: With a new 500kV single-circuit line between Longwood TS and Middleport TS
Approximate length of the new line: 150km.

- To maintain post-contingency transient stability, the 500kV circuits between the Bruce Complex and Longwood TS would need to be compensated to at least **20%** while those between Longwood TS and Nanticoke SS and between Longwood TS and Middleport TS would need to be compensated to at least **10%.**

- To limit the post-contingency flows through the 230kV circuits B4V & B5V, the level of compensation on the 500kV circuits would need to be increased to 40%. With this level of compensation installed, the post-contingency flows on the section of the 230kV circuits B4V & B5V between the Melancthon Projects and Orangeville TS would be within their 15km/hr wind-speed rating of 1590A.

Alternative 2.1 With a new 500kV double-circuit line between the Bruce Complex and Milton TS
Approximate length of the new line: 176km.

- For this Alternative there would be no requirement to install series capacitors on any of the 500kV circuits either to maintain post-contingency transient stability or to avoid post-contingency overloading.

Alternative 2.2 With a new 500kV double-circuit line between the Bruce Complex and Essa TS
Approximate length of the new line: 1826km.

- Similarly for this Alternative, there would be no requirement to install series capacitors on any of the 500kV circuits either to maintain post-contingency transient stability or to avoid post-contingency overloading.

- Remedial measures would, however, be required to raise the operating temperatures of the two existing Essa-to-Claireville 500kV lines. Since each of these lines is presently rated at only 1900MVA, they would be inadequate for the projected post-contingency flows of approximately 2600MVA.

Comparison of the Alternatives

Alternative 1, with a new 500kV single-circuit line installed between Longwood TS and Middleport TS would be substantially inferior to Alternative 2 involving a new 500kV double-circuit line between the Bruce Complex and either Milton TS or Essa TS, for the following reasons:

- It would require the 500kV circuits to be series compensated to a level of 40%.

  For Alternative 2, none of the 500kV circuits would require series compensation.

- It would require higher levels of post-contingency reactive support to be provided from the synchronous condensers at Nanticoke GS.

  Approximately 950MVAr of support would need to be available, whereas Alternative 2 would require a maximum of approximately 275MVAr.

- It would result in additional post-contingency losses of approximately 400MW, while for Alternative 2 the increased losses would be approximately 160MW.

- It would continue to present challenges for the re-preparation of the system to position it for any subsequent contingency.

  Since Alternative 2 involves the installation an additional, independent path from the Bruce Complex, a sustained outage involving circuits B560V & B561M would essentially return the system to the status quo. For this, the consequences of a single element contingency would be much less severe.

Of the two options for terminating the new 500kV double-circuit line from the Bruce Complex, the one with the line terminated at Milton TS instead of at Essa TS would have the advantage of avoiding the need to uprate the two 500kV lines between Essa TS and Claireville TS.

However, in all other respects, the performance of the two options would be similar.

3. Synchronous Condensers

With seven Bruce units together with 925MW of wind-turbine generation capacity incorporated and with the 500kV circuits equipped with series capacitors providing 50% compensation, approximately 1120MVAr of post-contingency reactive support is expected to be required from the synchronous condensers at Nanticoke GS.

This could be provided through the conversion of a minimum of three of the existing generating units at Nanticoke GS to synchronous condenser operation, although it would be prudent to convert an additional unit to maintain a degree of redundancy.

Once the new 500kV double-circuit line is placed in-service to coincide with all eight Bruce units being in operation, the reactive support requirement from Nanticoke GS would fall to approximately 275MVAr. This would be within the capability of a single synchronous condenser, or a maximum of two units if redundancy is to be provided.
Since the new 500kV line is required to be in-service no later than the end-2011, the period over which four synchronous condensers would need to be available would be a maximum of three years.

The IESO has therefore recommended that consideration be given to providing a portion of the reactive power requirements from Static VAr Compensators (SVCs). This would limit the number of units at Nanticoke GS that would have to be converted to synchronous condenser operation. In addition, once the new 500kV line is placed in-service and the reactive support requirements are reduced, any surplus SVC capacity could be relocated to other areas of the system that require dynamic voltage support.

4. Bruce Special Protection System

Enhancements to the Bruce SPS will be required to expand the number of contingencies to which it can respond as well as the range of actions that can be automatically initiated in response to these contingencies.

16.2 Recommendations

- The ABB Study that was commissioned by Hydro One has determined that sub-synchronous resonance (SSR) issues associated with the installation of series capacitors in the 500kV circuits connected to either the Bruce Complex or Nanticoke GS could be avoided if the level of compensation were to be maintained below 40%. This would avoid the need to employ mitigating measures such as using thyristor controlled series capacitors (TCSCs) for a portion of the series capacitor installation.

  The IESO has determined that installing 30% series compensation would not only avoid the need to uprate the 500kV circuit N582L but it would satisfy the requirement for a minimum level of 20% compensation to maintain post-contingency transient stability. However, the post-contingency flows on the section of circuits B4V & B5V between Hanover TS and Orangeville TS would exceed the 15km/hr wind-speed rating of these circuits.

The IESO is therefore recommending that the condition of this section of circuits B4V & B5V be examined to determine whether the line could be uprated for operation at a conductor temperature of 127^{o}C.

If circuits B4V & B5V can be uprated, then the IESO's preference would be to adopt a level of 30% compensation for the series capacitors that it is proposed to install on the 500kV circuits between the Bruce Complex and Longwood TS and between Longwood TS and Nanticoke SS.

- Since extensive modifications to the Bruce SPS are expected to be necessary to provide the additional flexibility that will be required, and in recognition of the complexity of the existing scheme and the associated difficulty of implementing changes, the IESO would support a change to a matrix-based design, similar to that which has been used for other SPSs.

- In the accompanying analysis, extensive use has been made of the 15km/hr wind-speed ratings for the 230kV circuits B4V & B5V in assessing whether post-contingency overloading is expected to occur.

  Since the prevailing ambient conditions are expected to have a major influence on these ratings and therefore on the operation of the system with particular emphasis on the post-contingency responses that are adopted, the IESO is therefore recommending that these circuits be equipped with real-time monitoring.

- Since the installation of series capacitors in the 500kV circuits between the Bruce Complex and Nanticoke SS will result in increased pre- and post-contingency flows on the 500kV circuit N582L, this could result in more pronounced voltage imbalances on the 115kV circuits that supply Norfolk TS and Tillsonburg TS.

  The IESO is therefore recommending that the design of the existing Independent Phase Controlled Compensators at Norfolk TS and Tillsonburg TS be reviewed to determine whether they have adequate capability to address the expected voltage imbalances that could arise once the series capacitors have been installed.

17. Customer Impact Assessment

Once a decision is made whether or not to proceed with the installation of series capacitors and the level of compensation that is to be employed, Hydro One Networks Inc. is proposing to conduct a Customer Impact Assessment for this Project to determine whether the proposed facilities could have any materially adverse effects on their customers.

Should any issues be identified in the CIA then they will be addressed through an n Addendum to this Report.

18. Notification of Approval of the Connection Proposal

Subject to the completion of the Customer Impact Assessment and the satisfactory resolution of any issues that it may raise, the IESO has concluded that the following work will have no materially adverse effect on the IESO-controlled grid:

- the installation of series capacitors in the Bruce-to-Longwood and the Longwood-to-Nanticoke 500kV circuits, whether at the 50% or 30% compensation level, and subject to appropriate action to uprate either the 500kV circuit N582L (for 50%) or the 230kV circuits B4V & B5V (for 30%).
- the installation of 230kV shunt capacitor banks at Middleport TS, Nanticoke TS, Detweiler TS & Orangeville TS
- the conversion of up to four units at Nanticoke GS to synchronous condenser operation, and/or the installation of SVCs to provide a portion of the reactive power support that will be required.

It is therefore recommended that a Notification of Conditional Approval to Connect be issued for this Project

Exhibit No. 13

ELECTRANIX
Electranix Corporation.

Final Report

Due Diligence Study and Development of High Level Planning Specifications for the Installation of 500 kV Series Capacitor Banks in the Southwestern Ontario Transmission Network

For the
Ontario Power Authority
OPA Purchase Order No. 50000488
OPA Project Manager: Jim Lee

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October 5, 2007

Summary

This report evaluates specific use of series capacitors on the 500 kV network in the Southwestern Ontario (SWO) electricity system. Previous investigations have been reported on series capacitor applications by ABB [1] and the IESO [2], [3]. Although series capacitors applied to high voltage transmission systems is a mature technology with hundreds of successful installations in service in North America and around the world, the resulting impact they may have on the ac system is complex and severe. The main issues are:

1. **System Reliabilit**y. Generally, adding series capacitors to existing transmission lines without adding additional circuits to accommodate increased power flow causes parallel circuits to be more highly loaded under contingency conditions. This results in a higher average line and transformer loading which can be thought of as an ever growing stress on the network. This wide spread stress exacerbates the impacts of routine contingencies and the latent failures and grid imperfections that compound them.

   Generally, adding series capacitors instead of additional circuits tend to speed the transition from one worse case contingency event and one worst case limiting element to multiple worst case events and multiple limiting elements, making grid failures from severe contingency events more likely. The series compensated and, seemingly robust network carrying ever more power is not only less reliable for the above reasons, but opens the door to impacts of contingencies and cascading over larger areas. Careful design of the Bruce special protection system (BSPS) can counteract reduced system reliability when adding series capacitors for these increased power flows but is a complex adjustment to do successfully. In addition, careful design applied to each series capacitor bank can minimize the impact of failure modes within the bank and its consequential negative influence on system reliability.

2. **Sub-synchronous resonance (SSR)**. SSR is one of the most significant aspects that require attention. Although the undesired overlap of generator shaft torsional modes with the complementary electrical resonance is less likely the lower the level of series compensation applied, there is no guarantee that sub-synchronous resonance can be avoided altogether. With the 30% level of series compensation considered for application in Southwestern Ontario (SWO), it appears the Nanticoke generators under transmission contingency conditions will be more susceptible to sub-synchronous resonance than the units at Bruce under contingency conditions. For the period of time that the Nanticoke generators will be in operation after the

Introduction

This report is prepared in response to a request from the Ontario Power Authority (OPA) for consulting services to evaluate specific use of series- capacitors on the 500 kV network in the Southwestern Ontario electricity system. Studies have already been undertaken by ABB [1] and the IESO [2], [3] on proposed transmission developments in Southwestern Ontario (SWO), and comments based on experience and knowledge of series compensation and related issues are to be provided. Additionally, data for a high level technical specification is to be supplied as a deliverable.

The above referenced ABB and IESO reports contain a significant amount of information on the option to series compensate the two 500 kV transmission lines from Bruce to Longwood (B562L and B563L) as well as the single transmission line from Longwood to Nanticoke (N582L). It was concluded that generating units at Bruce and Nanticoke were susceptible to sub-synchronous resonance conditions under certain contingencies. This study reviews the technical aspects of applying series capacitors to the Southwestern Ontario (SWO) system and provides a high level planning specification for the purchase, installation and commissioning of series capacitors. To reduce the threat of sub-synchronous resonance, the application of series capacitors at the 30% compensation is considered.

1. Series Capacitor (SCAP) Application for SWO

1.1 Risks with Series Capacitors

1.1.1 Appropriateness of Employing Series Capacitors

Uncompensated transmission assets are normally under utilized, particularly if their length is such that their power transfer capacity is impedance and stability limited (through voltage collapse or angular instability) rather than thermally limited. Applying series compensation with series capacitors (SCAP) is an accepted method of increasing the transfer capacity of a high voltage transmission line that is impedance limited. The transmission impedance is reduced allowing more power to be transferred along the line.

Series capacitors have been successfully applied to high voltage transmission lines since 1948. Over those years the effectiveness of series capacitors has been substantially improved with metal oxide varistors (MOVs) or surge arresters, improved protection, damping of sub-synchronous resonance

(SSR), and application of power electronics to improve damping of angular stability oscillations and also provide damping of SSR. The application of MOVs since the early 1980s has eliminated the technical challenges of re-insertion following an ac system fault.

Series capacitor application to high voltage transmission lines, and at 500 kV is a mature technology in North America and around the world. In Canada, BC Hydro (now BCTC) was the first to apply series capacitors at 500 kV. The 500 kV Winnipeg to Twin Cities 500 kV interconnection between Manitoba and Minneapolis was series compensated as a staged upgrade, increasing the power transfer capability from 1000 MW to 1,500 MW. Hydro Quebec added series capacitors to their 735 kV transmission network to achieve increased power transfer capability and improved contingency performance.

An important side benefit of the Manitoba Hydro and Hydro Quebec series capacitor upgrades was the substantial reduction in impact of geomagnetic currents. Severe geomagnetic storms had caused operational problems in both Manitoba and Quebec. In the late 1980's a severe geomagnetic storm precipitated a system wide blackout in Quebec that the later installation of series capacitors has all but eliminated such a disturbance reoccurring again.

Geomagnetic storms induce currents in grounded transmission systems, which if severe enough cause power transformers and instrument transformers to saturate. The consequential distorted currents that flow through the transmission system may overheat the saturated transformers and cause protective relays to falsely operate. The effect is most severe in northern locations. Series capacitors fully protect a transmission line from geomagnetic induced currents. However, the SWO system although subject to a limited effect of geomagnetic induced currents with its absence of series capacitors, has not had its operation limited or restricted by them. Thus series capacitors appear to not be essential for protection of the SWO system against geomagnetic induced currents.

1.1.2 Potential Risks of Applying Series Capacitors

Expanding transmission capacity between available generation in order to meet increasing load such as in SWO has traditionally and preferably been accomplished with new transmission lines. Additional transmission lines preserve reliability of supply under transmission outages as well as minimize losses. A limited option to new transmission is the use of series capacitors on existing transmission as a way to increase transfer capacity, or as a bridging measure before new transmission is built. However, system losses increase compared to having a new transmission line which when capitalized will diminish the economic gains the relatively low cost series capacitors appear to offer.

Adding series capacitors to existing transmission lines without adding additional circuits to accommodate increased power flow causes parallel circuits to be more highly loaded under contingency conditions. This results in a higher average line and transformer loading which can be thought of as an ever growing stress on the network. This wide spread stress exacerbates the impacts of routine contingencies and the latent failures and grid imperfections that compound them.

Generally, adding series capacitors instead of additional circuits tend to speed the transition from one worse case contingency event and one worst case limiting element to multiple worst case events and multiple limiting elements, making grid failures from N-2 events more likely. The ever larger and, seemingly robust network carrying ever more power is not only less reliable for the above reasons, but opens the door to impacts of contingencies and cascading over larger areas.

Series capacitors need to be applied with considerable care to ensure that they do not result in severe damage to thermal generators such as at Bruce and Nanticoke. Most significant is sub-synchronous resonance [1], which is more likely when a generating plant under contingency operation, is radial, or dominantly radial through the series compensated transmission line. If the electrical series resonance of the generators and transmission lines are complementary to a mechanical resonant modal frequency of the generator shaft, then negative damping of the shaft torsional oscillations may occur, which will lead to shaft damage if not remedied.

Fortunately the mechanism of SSR, its analysis and design for prevention is now well known and a number of mitigating measures exist to address this issue (see Section 1.1.4). Generally it is true that the lower the proportion of series compensation on a transmission line, the less likely the electrical series resonance will decrease damping of complementary shaft torsional resonant modes and cause shaft damage. Failures of a steam turbine shaft noticeably occurred on the Mohave Generator in Nevada in December 9, 1970 and October 26, 1971. These failures were directly attributable to network switching conditions that instigated SSR with the level of series compensation of the 500 kV transmission at 70% [10]. Consequently, due diligence on SSR as it might adversely impact the SWO generation when series capacitors are added to the SWO 500 kV transmission system is imperative and has been instigated [1], [2], [3]. Series capacitors, even if not resonant at a frequency complementary to a generating shaft torsional frequency, can still reduce the damping of shaft resonant modes through reduced electrical damping. If significant, shaft aging may be accelerated if torsional oscillations normally invoked by transmission line switching and fault clearing will take longer to damp. This is like bending a wire back and forth, which if continued long enough will cause the wire to break.

This report investigates and expands on the probable risk situations identified above.

1.1.4 Application of Suitable Mitigation Measures

When SSR problems are determined to be a risk, mitigation methods that can be applied in order of practicality and cost include:

1. Operating restrictions upon detection specific transmission contingencies.
2. Excitation system damping of SSR.
3. Ensure any power electronic controller in the vicinity of an impacted generator provides positive electrical damping to the torsional frequencies of the shaft. Such a controller could be a static var compensator (SVC) or STATCOM.
4. AC filters tuned to SSR electrical frequencies.
5. Damping circuit added to portion of the series capacitor (such as a thyristor controlled series capacitor (TCSC) or NGH damping controller).
6. Conversion of series capacitor to a solid state series capacitor (SSSC).

Damping controllers can be of a “broad-band” design or can target narrow frequency ranges to isolate specific modal frequencies. If the torsional data for the problematic generator is available, then a narrow frequency range solution is preferred to localize the control changes to the local machine and frequency range. If the shaft data is not available, then broad-band mitigating methods will be devised but should be used cautiously since they could potentially have negative impacts elsewhere in the system.

Finally, after successful mitigation measures have been designed, the generators at risk to SSR should all be protected with a torsional stress relay as a safely net.

1.2 Summary of Major Series Capacitor Installations World Wide

1.2.1 High Voltage Series Capacitor Installations

A survey of five major suppliers of series capacitor installations resulted in responses from four (4). Appendix A provides a list of the series capacitor installations provided from each of the responding suppliers. A summary of the data shown in Appendix A is included in Table 1.2.1.

Table 1.2.1

Summary of World Wide Series Capacitor Installations

Supplier	MVAR Supplied	Number of Installations	Maximum Voltage	Maximum MVAR	Maximum MOV/Phase
ABB	76,352	265	760 kV	2,096	Not Stated
GE	52,776	157	735 kV	1,242	196.4 MJ
Nokian	26,506	75	750 kV	1,056	75 MJ
Siemens	22,076	65	765 kV	765	59 MJ
Total	177,710	562			

1.2.2 Series Capacitor Applications

Suppliers of series capacitor installations do not generally document the application for which their equipment is being used by the host utility. However, based on past experience of team members preparing this report it is the consensus that most applications of series capacitors are for improving power flow on critical transmission paths and also for transient stability improvements.

1.2.3 Compensation Levels

Appendix A provides a summary list of series compensation sizes (MVAR) provided by suppliers. The list does not include the percentage compensation that the individual installations provide but rather the MVAR ratings. In general, if the total MVAR of series compensation listed in Table 1.2.1 is divided by the total number of installations, an average MVAR/installation would be approximately 316 MVAR/installation, which is slightly less than the assumed 30% compensation for the B562L, B563L and N582L lines.

In North America, there are no series compensated transmission lines that connect thermal generators radially to the network under a no contingency condition. However, since they are installed in a meshed network, they may revert to a radial connection under contingency conditions. The series capacitors on the 735 kV transmission system in Quebec are in radial transmission lines but from hydroelectric generators, which are not prone to SSR. The significance of a radial connection is that all the power from the generator passes though the series capacitor. If the generator is connected to a meshed network, then some portion of generated power is diverted or attenuated into other circuits so that the severity of SSR is diminished. Hydroelectric generators have very stiff shafts compared to the shafts of steam turbines and are virtually impervious to SSR even when radially connected through series compensated transmission lines.

1.2.4 Number of Installations

Although the initial series capacitor installation occurred in 1928, it would take until the 1960's before the technology began to expand. Figure 1.2.4.1 indicates a time line beginning in 1948 when 55 MVAR of series capacitors were delivered through 2007 when approximately 3,045 MVAR were in delivered. In 2003 the delivery of series capacitors peaked with approximately 13,045 MVAR produced on a world wide market.

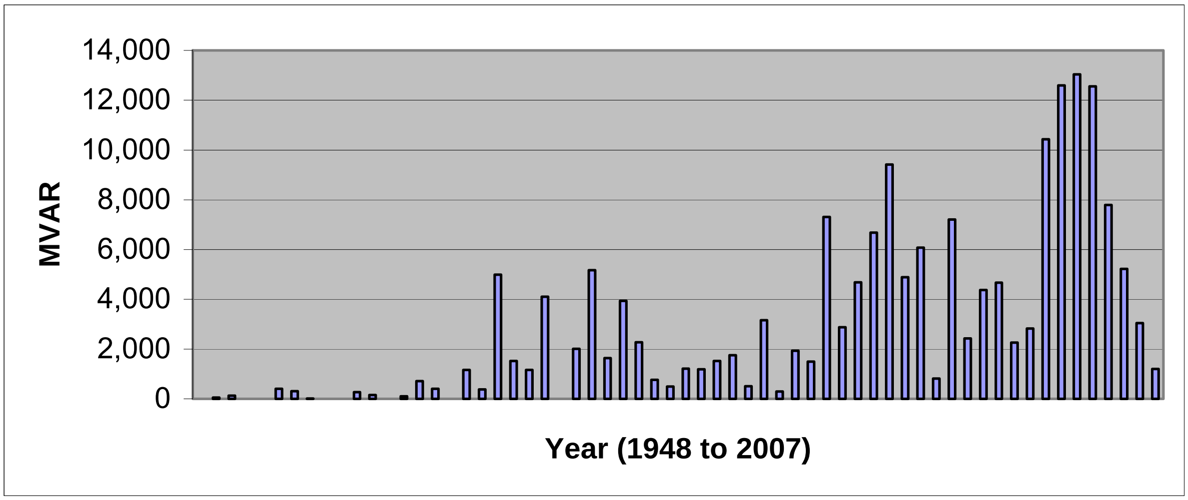


Figure 1.2.4.1

Annual World Wide Series Capacitor Deliveries

An overview of a sample series capacitor project time-line is shown in Figure 1.2.4.2. Task 1.0 (Specification Preparation) and Task 2.0 (Request for Proposals & Award) can require a significant amount of time depending on staff availability and work load of the purchasing utility. A twelve (12) month period has been allocated to Tasks 1.0 and 2.0 following project authorization and approval. Tasks 1.0 and 2.0 would include the following major efforts:

> Task 1.0 – Specification outline, system studies, technical specification and procurement coordination.
>
> Task 2.0 – Issue Request for Proposal (RFP), pre-bid meeting, supplier proposal preparation, proposal evaluation, supplier clarifications, negotiations and contract award.

Following contract award an eighteen (18) month period has been allocated to Task 3.0 (Design & Engineering) through Task 8.0 (Commercial Operation). Tasks 3.0 through 8.0 would include the following activities:

Task 3.0 – Final system studies, equipment studies, protection and control design, site design and project review meetings. This would also involve design support from the utility.

Task 4.0 – Manufacturing of capacitor units, protection and control hardware, other platform equipment, platform structure and other needed equipment.

Task 5.0 – Factory testing of all equipment including protection and control, real time digital simulator (RTDS) testing, shipping and on-site receipt of equipment.

Task 6.0 – Site work would include grading, foundations, fencing, building construction, inspection, cabling and all equipment installation.

Task 7.0 – Commissioning activities include operator and maintenance training, pre-commissioning of subsystems, high voltage energization, acceptance testing and trial operation tests.

Task 8.0 – Commercial operation would signal the start of the warranty period during which the installation would be monitored by the utility to ensure contract performance requirements are being met.

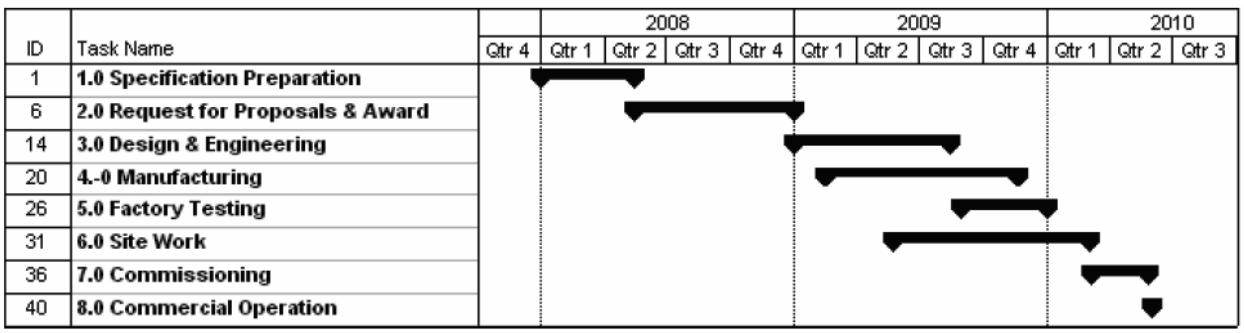


Figure 1.2.4.2
Sample Project Time-Line

1.2.5 Special Features

Special features that have been incorporated into series compensation systems over the years include advancements in hardware, software and analytic capabilities. These advancements have improved the performance of series compensation systems and reduced their level of maintenance to the point that transmission line applications that improve power flow and system stability have become widespread. Early installations had performance and maintenance problems. Now the advancements have dealt effectively using special features that include the following:

Critical single units such as the by-pass switch, damping circuit and spark gaps (if installed) are alarmed and protection signals generated when failure occurs and the by-pass instigated as described in Table 3.2.2. The fail-safe operation of the by-pass switch to the normally closed position is the basic protection back-up. The failure of the by-pass switch to close when protection requires it to do so may result in component failure, which in some instances could be catastrophic.

3.3 Availability of Series Capacitor Installations

3.3.1 Availability Statistics

Typical availability statistics of series capacitor installations throughout the world are not published. However, it is not unusual for series compensation systems, including their ancillary equipment, to be specified with guaranteed availability performance requirements of 99.6% to 99.7%. The number and duration of scheduled maintenance outages of fixed series capacitor (FSC) banks each year typically do not exceed 1 outage for a maximum duration of 12 hours with no more than 2 forced outages per year. To realize the availability performance requirements it is necessary to identify some terms and definitions when purchasing the installation.

The following definitions could be applied:

1. Forced outages are outages caused the by FSC bank equipment that result in loss of part or all of the FSC bank essential functions.
2. Scheduled outages are outages necessary for preventive maintenance to assure continued and reliable operation of the FSC bank.
3. Outage duration is the elapse time (in hours) from the instant the FSC bank is out of service to the instant it is ready to be returned to service. If the FSC bank becomes available for service during non-working periods, such time should not be included in the outage duration if the User elects not to return the FSC bank to service. The following should be included in outage duration:

    a. Time required to determine the cause of an outage or to determine which equipment or units of equipment must be repaired or replaced.
    b. Time required by system operators and technicians to disconnect and ground equipment in preparation for repair work and to remove grounds and reconnect equipment after repairs are completed. Delays caused by unavailability of qualified User personnel should be excluded from the outage duration.
    c. If partial FSC bank ratings are available, the duration of equivalent outage should be calculated as the product of the derated condition duration and the proportion of the nominal output MVAR range which cannot be achieved during this period.

Equipment Specifications

_____ From the Facilities Study, finalize the list of facilities that require addition and replacement. Prepare a schedule for purchase and installation, and set up appropriate budgets and purchasing policies, and project management.

_____ Prepare the technical specifications for the series capacitor installations.

_____ Prepare of the technical specifications for the additional facilities identified in the Facilities Study including fixed, switched and dynamic compensation, replacement transmission line protection systems, updating of the BSPS and replacement of any existing facilities such as surge arresters, circuit breakers and instrument transformers.

_____ Proceed with the purchase of all necessary facilities including land acquisitions.

_____ Construct, test, commission and accept of all new and replacement facilities.

_____ Adjust settings of existing equipment if changes are necessary including excitation stabilizers for increased system damping, exciters with improved SSR damping functions, and any protection relays the would benefit from revised settings.

_____ Consider the installation of torsional stress relays if SSR studies indicate a need.

The sequence of the checklist items may be adjusted to accommodate the overall schedule of the project.

Conclusions

The main conclusions are:

1. Series compensation is a mature technology that has been effectively and reliably applied for many decades.
2. The rating of the series capacitor banks is based on equaling the conductor rating so that they are not limiting power transfer capability.
3. By restraining the degree of series compensation to 30%, there appears to be no torsional mode conflicts with any of the Bruce generators. There are torsional conflicts with the Nanticoke units, which if retained in service after the series capacitors are in operation, require further

Exhibit No. 14

10-YEAR OUTLOOK:

An Assessment of the Adequacy of Generation and Transmission Facilities to Meet Future Electricity Needs in Ontario

From January 2006 to December 2015

ieso
Power to Ontario.
On Demand.

5.1.7 System Requirements Associated with the Incorporation of Bruce Units

The Bruce system consists of eight nuclear units, totaling approximately 6,500 MW of capacity, connected to the power system through four 500 kV lines (two circuits from Bruce to Milton TS, one of which continues on to Claireville and two circuits from Bruce to Longwood TS), and six 230 kV circuits (two circuits from Bruce to Orangeville, two circuits from Bruce to Detweiler and two circuits to Owen Sound, one of which connects to the 115 kV network through to Essa). The Bruce complex is the largest concentration of generating units in North America.

The generation was installed over the mid 70’s to mid 80’s. Four units were removed from service in 1998, at the same time as four Pickering units. Of these four Bruce units, two units have since been returned to service in 2003. Two units (1 and 2) remain out of service.

The transmission additions constructed to incorporate the station into the Ontario network were not as desired by Ontario Hydro. The preferred implementation included a double circuit 500 kV line from Bruce to Essa in the Barrie area. Public opposition to these circuits ultimately prevented this construction. The Bruce to Longwood 500kV circuits were installed as a somewhat less capable alternative. As a result of this change, the full output of the Bruce complex could not be accommodated by the transmission system. In order to increase the capability of the transmission system to the level required, an automated “Special Protection Scheme” (SPS) was installed. In taking this step, the reliability of both the Bruce generation and many customers in Ontario was reduced to achieve increased economic benefits of the Bruce complex. In essence, the SPS allows for detection of certain power system events and immediately disconnects generators at Bruce and a large amount of customer load throughout southern Ontario to prevent a system disturbance such as that experienced in August 2003.

Without the SPS, Bruce output is limited to approximately 5,000 MW (capacity equivalent to approximately six Bruce units). With the SPS, Bruce output with eight units in operation (6,500 MW) could be accommodated provided up to four units (3,200 MW) were ‘rejected’ or disconnected instantaneously together with 1,500 MW of customer load (approximately half the load in downtown Toronto). These extensive and complex automatic actions, representing by far the largest use of an SPS by an interconnected system operator, were considered a temporary measure until additional transmission could be constructed. Ontario’s neighbouring system operators insisted on stringent conditions with respect to the design and use of the SPS in order to protect their own systems from a cascading disturbance. The majority of the SPS has not been used in over a decade following the shutdown of four Bruce units in 1998.

In the consideration of additional Bruce generation, it is important to understand the relationships of the various factors which impact on the ability of the system to accommodate increased Bruce generation, as well as how the evolution of the electricity system has affected this capability. This information is summarized in the following table.

Table 5.1 Factors which Reduce Ability to Accommodate Increased Bruce Generation

Factors	System in 1980’s	Current System
1. Southern Ontario Power Flows are from West to East; - Power flows from	- Ontario is an exporter of	- Ontario is an importer of

Factors	System in 1980's	Current System
Michigan to Ontario - The amount of generation in south western Ontario increases	power to Michigan - Lambton is the only generation in the area (2000 MW)	power from Michigan - Lambton (2000 MW) - TA Sarnia & Dow (635 MW) - Brighton Beach (580 MW) - Imperial Oil (100 MW) - TA Windsor (80 MW) - West Windsor (130 MW)
2. The number of Nanticoke units in Operation is reduced	- Eight units available	- Eight units available - Unit reliability declining
3. Increased need for power flows into the GTA from the west		
- Increased load in the GTA	Peak system load (1984) Winter 18,800 MW Summer 15,800 MW	Peak system Load Winter 25,000 MW Summer 25,500 MW The large majority of this increased load is in the GTA and vicinity
- The power factor of load decreases	Reasonable power factor	Power factor has declined markedly as a result of air-conditioner load, reflecting summer peaking trend in Ontario
- The generation in the GTA decreases	Lakeview 1,200 MW Hearn 400 MW Pickering 4,120 MW	Lakeview 0 MW Hearn 0 MW Pickering 2,575 MW (unit reliability degraded) Darlington 3,600 MW

In each case, the evolution of the system has been to reduce the capability of the system to accommodate additional Bruce generation. Of course this is not exclusively true; for example, Darlington was constructed to help meet GTA load, expansion of the 500 kV network in south western Ontario has been undertaken and a large number of shunt capacitors have been added in the GTA. However, in general, the net effect has been negative from the perspective of accommodating additional Bruce generation.

In addition, the past reliance on the large 'Special Protection Scheme' to accommodate Bruce output is no longer a desirable practice. The three and four unit rejection associated with this scheme as well as associated customer load rejection have not been required to be used in a decade. The experience of the August 2003 blackout has altered industry and system operators view of the risks associated with use of these schemes. The side-effects of their operation may no longer be acceptable. The IESO does not recommend reliance on an SPS of this magnitude that involves the rejection of more than 2 generating units combined with extensive load rejection. There is a high degree of uncertainty with respect to our neighbours' agreement with such a scheme's future use. The IESO believes it is prudent to enhance the transmission system so that generation rejection is limited to 2 Bruce units, and the load rejection portion of the special protection scheme is not required to be used in conjunction with generation rejection to maintain Bruce stability. The load rejection portion of the scheme should be maintained only to overcome difficulties in the operating time frame that would otherwise require pre-contingency load shedding. From the late 1990's this was not a major concern as there were no firm plans to rehabilitate units at Bruce. When this became desirable, the studies performed by the IESO, Hydro One and Bruce Power have identified the need for transmission expansion to accommodate additional generation at Bruce. This may take the form of series compensation of existing transmission lines or the additional of new transmission lines.

In summary, the existing system is much less capable of accommodating additional supply at Bruce than it was in the past. A number of factors associated with the dynamic and changing nature of the system have contributed to this including:

- High load growth in the GTA, particularly in summer as air conditioner use has surged;
- Changing nature of the load in the GTA;
- The shutdown of Pickering A;
- The shutdown of Lakeview;
- The growth of imports from Michigan on-peak;
- The addition of generation in southwest Ontario;
- The overall reduction in dependability of some OPG facilities; and
- Changing industry expectations with respect to use of large 'Special Protection Schemes'.

Even with transmission enhancements, it is recognized that the incorporation of additional Bruce units together with the need to cease burning coal at Nanticoke will require significant changes in the supply and delivery infrastructure.

Fortunately, the same types of system developments required to eliminate the need for Nanticoke generation described earlier this section are the same enhancements needed to accommodate additional generation at the Bruce site. These developments include the following:

- Installation of generation in proximity to the large GTA demand. Location of generation close to the load facilitates the installation of additional generation at Bruce in two ways; first, less energy needs to be transported long distances to the GTA reducing competition for transmission capability between Nanticoke and Bruce, and second, reactive power needs of the system are met by the local generation in the GTA;
- Installation of series compensation in the 500 kV lines serving Bruce and Nanticoke. This form of compensation reduces the need for reactive power to support the large power flows to support the GTA, and reduces the need for post-contingency voltage support; and
- Installation of shunt capacitors in southwestern Ontario. This form of compensation provides voltage support to the steady state power system, freeing up dynamic voltage control capability of generating units.

- As was the case for the shutdown of Nanticoke, it is unlikely that these measures will eliminate the need for dynamic voltage support from the Nanticoke site. The most effective means to provide this capability while meeting the government's policy to cease burning coal at Nanticoke is to convert several units to synchronous condenser operation.

5.1.8 Retirement of Atikokan Facilities

A reliability assessment of the Northwest Zone of Ontario has demonstrated that the Atikokan station may be shut down without replacement. These studies demonstrate that the Northwest Zone of Ontario will continue to be compliant with the NPCC A-2 reliability criterion requiring a Loss of Load Expectation (LOLE) of not more than 0.1 days per year, under conservative input assumptions. Under normal operation the area far exceeds the specified reliability criterion. Due to the nature of the northwest system, the study considered probabilistic reductions to transmission interface capabilities between the Northwest and Northeast Zones, and assumed significantly lower than median resource availability from hydroelectric resources in the Northwest zone.

While operation without Atikokan capacity is acceptable from an adequacy perspective, transmission infrastructure changes are required to ensure system security needs are met. Retirement of Atikokan removes an important source of voltage support necessary to support energy flows throughout the long distances inherent to the Northwest system. The additional of shunt capacitors at Fort Frances and or Mackenzie TS will compensate for the retirement of Atikokan.

5.1.9 Treatment of Interconnections in the Coal Replacement Plan

Interconnection capability provides a number of benefits to the Ontario system and market participants. One very important aspect of the availability of energy from interconnections is in response to unforeseen near-term capacity and demand variations. The large centralized nuclear generation facilities in Ontario can expose the system to large capacity availability variations. Similarly, extreme weather in Ontario can result in extremely high temporary requirements for generation. For these reasons it was decided not to rely on interconnections for capacity requirements during the coal replacement transition, but rather to consider generation in Ontario for this purpose. Long term use of interconnections for capacity purposes should be based on the construction of additional interconnection capability, ensuring sufficient capability remains for current purposes.

5.2 System Transition Risk Mitigation

The transition from coal to replacement clean supply is an extremely challenging objective. In terms of the amount of coal generation to be replaced, an amount of clean supply larger than all of the hydroelectric capacity in Ontario must be arranged for, constructed, commissioned and reach a reliable state of operation.

This transition must take place:

- Without jeopardizing electricity reliability;
- Within the capabilities of the industry to deliver; and
- Within the tolerance for change of electricity consumers.

Exhibit No. 15

Ross IESO INTERROGATORY #10 List 1

Interrogatory

Ref. Exh. B / T 6/ S4 / P6
Issue Number: 1 Project Need and Justification

Preamble:

In the **Ontario Reliability Outlook –** March 2007, Volume 2 Issue 1 document, the IESO states that "A new 500kV line out of the Bruce area is required as soon as possible to accommodate additional generation expected from new projects and refurbished Bruce nuclear units."

In the **10-YEAR OUTLOOK:** An Assessment of the Adequacy of Generation and Transmission Facilities to Meet Future Electricity Needs in Ontario From January 2006 to December 2015 study released in August of 2005, the IESO states at page 27 that, "Hydro One has submitted an application to the IESO for a connection assessment of their proposal to install series capacitors at the approximate mid-points of the following 500 kV circuits, Preliminary analysis shows that this plan has the potential to accommodate the proposed return to service of Bruce A Units 1 and 2, and also intended to reduce the reactive power losses of the existing system, particularly under contingency conditions, and thereby decreasing the dependence on Nanticoke GS for voltage support, so that this generation facility can be removed from service."

Please reconcile these two positions.

Response

The 10-Year Outlook was released shortly after the IESO began consideration of using series compensation on the Bruce to Milton line. The 10-Year Outlook also notes that the IESO has yet to perform its full assessment of the impact of the 500 kV series capacitors at the paragraph immediately following the reference above.

Detailed analyses were subsequently carried out for both series compensation and the Bruce to Milton line by the IESO and were presented in SIA documents. Please see the response to Pappas Interrogatory 1 for the series compensation SIA and Exhibit B, Tab 6, Schedule 2 for the Bruce to Milton line SIA.

Consistent with the conclusion of the series compensation SIA, the installation of series capacitors is sufficient neither to accommodate all of the committed Bruce Area generation, nor to enable the development of additional potential wind resources in the area. The above references are accordingly consistent with each other.

Exhibit No. 16

Ontario Energy Board (Board Staff) INTERROGATORY #1.4 List 1

Interrogatory

Issue Number: 1.1
Issue: Has the need for the proposed project been established?

Ref B/Tab 1/Sch 3/p. 2

Preamble:

(a) The Applicant states that the new proposed line is needed to accommodate a shortfall of transmission capacity from the Bruce area that will reach 3,100 MW (2,100 MW by 2012 plus assuming the development of 1000 MW wind generation in the Bruce area).

(b) It is important to to examine the historical performance of the existing transmission system as well as the performance of the generation rejection system (GR) in dealing with contingencies and consequential safe operation of the transmission lines.

Questions:

(i) How many single circuit outages (classified as “momentary” - less than 1 minute, and “sustained”) have occurred on the existing Bruce to Milton and Bruce to Claireville lines (B560V and B561M) since they went into service?

(ii) How many simultaneous double circuit outages (classified as “momentary” - less than 1 minute, and “sustained”) have occurred on these lines in the same time frame?

(iii) In the various double circuit sections of the Hydro One 500 kV transmission system (excluding the Essa TS to Hamner TS section), what percentage of the “sustained” forced outages that occurred since the lines went into service involved outages of both lines simultaneously?

(iv) Is there a “sustained” forced outage percentage beyond which Hydro One would consider double circuit lines built on separate towers to deal with the common mode failure scenario of constructing two lines on the same tower?

(v) Please provide a full description of the Generation Rejection Scheme that was utilized during the period when all 8 units at the Bruce complex were operational delivering about 6,500 MW to the electricity system.

(vi) Please explain whether or not the GR scheme identifies certain loads connected to the transmission network and would trip them off i.e., disconnect such a load in order to maintain stability of the system?

(vii) Please provide a complete history of all incidents from the in-service of the GR until it was taken out of service, providing for each incident the following information:

a. Date and Time;

b. The trigger events e.g., fault on certain system element (500 kV transmission line or Autotransformer) or false trip event of the protection scheme.

c. Cause of failure of the system element or the false trip of a protection scheme

d. Which generating units at the Bruce Complex were rejected

Response

Hydro One does not possess transmission outage data prior to Jan 1990 and accordingly the provided information only covers the period from Jan 1990 to Oct 2007.

(i)

Circuit	No. of Momentary Outages (less than 1 min)	No. of Sustained Outages (1 min or more)
B560V	9	11
B561M	6	7

(ii)

Circuit (s)	No. of Momentary Outages (less than 1 min)	No. of Sustained Outages (1 min or more)
B560V & B561M	2	1

On September 15, 1998, at 15:08 Circuit B560V experienced a momentary outage while Circuit B561M experienced a sustained outage (26.88 hours). Those events are accounted for as a common mode momentary outage in the above summary .

In addition, on May 31, 1985 a tornado incident caused an outage on both circuits. This event is not reflected in the above 1990-2007 data.

(iii) Hydro One did not experience any common mode sustained outages to other 500 KV transmission corridors during the January 1990 to October 2007 period.

(iv) No, an outage percentage would not be used in this manner. According to NERC and NPCC Standards, additions to the transmission system are planned using deterministic and not probabilistic criteria.

(v) The Bruce Special Projection System (BSPS) is a collection of special protection systems installed at Bruce GS and associated stations that perform pre-defined control actions (such as: generation rejection, reactor tripping and load rejection) in response to recognized contingencies in the Bruce area. By providing these capabilities, restrictions on the maximum output of Bruce GS and other system parameters can be reduced or eliminated, while still respecting the established system criteria for voltage stability and equipment thermal loading. The BSPS was installed in 1991 and has had three modifications since it was placed in-service.

The BSPS monitors breaker and switch status in the transmission system in the Bruce area to determine how the transmission circuits are connected together. When it determines that a critical transmission contingency has occurred by monitoring breaker status, it initiates a pre-planned control action.

Three main control actions are available:

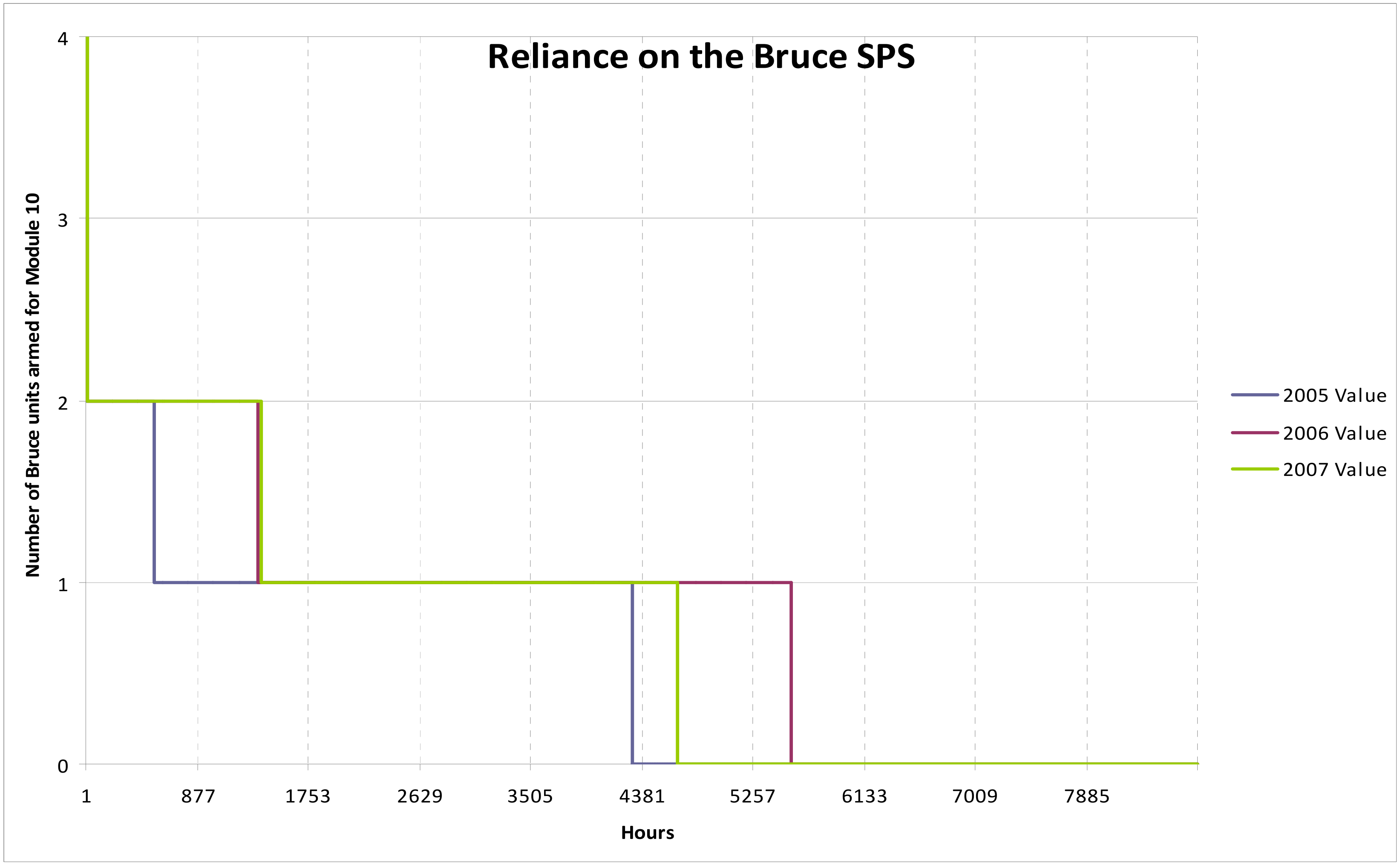
Generation rejection: Pre-selected generating units at Bruce A and/or Bruce B are automatically disconnected. The scheme has the capability of rejecting any of the eight units and multiple units can be selected for one event. A modification to enable the rejection of transmission-connected wind farms in the Bruce area is currently underway. Currently, only the Melancthon wind farm near Shelburne can be rejected. By June 2008, the capability to reject the Enbridge Underwood and the Ripley Majestic wind farms will also be available.

Load Rejection: The load at pre-selected transformer stations that are mainly located in south-central Ontario can be disconnected in response to a contingency.

Reactor switching: Shunt reactors used for voltage control that are located at both the Bruce A TS and the Longwood TS in London can be switched off following a contingency in order to increase voltage at those locations.

(vi) While the scheme is capable of rejecting load, the scheme does not identify such a condition automatically. Instead, the IESO directs the operation of the scheme and determines if it is necessary to reject load. The IESO then determines which load to select for rejection. Hydro One then manually selects that load for rejection. The scheme will then reject the load if a particular contingency occurs.

(vii) The Bruce Special Protection System (BSPS) has not previously been taken out of service and remains in effect today. A history of incidents in which the BSPS has actually been triggered is not available. A 3-year history of arming incidents (i.e., the number of hours in 2005, 2006, 2007 that the BSPS was armed to increase transfer capability to address transmission outages) is provided below in a graph. The graph indicates that the BSPS was armed approximately ½ the year or more for at least 1 unit in those years, indicating the reliance on BSPS as a potential mitigation measure.


Reliance on the Bruce SPS
Number of Bruce units armed for Module 10
4
3
2
1
0
1
877
1753
2629
3505
4381
5257
6133
7009
7885
Hours
2005 Value
2006 Value
2007 Value

1

Exhibit No. 17

Pollution Probe INTERROGATORY #34 List 4

Interrogatory

Ref. Exh. B/T 6/S 4 is the Ontario Reliability Outlook – March 2007. On page 3, it states: “Without new transmission facilities, the IESO will eventually be forced to operate existing facilities near their maximum capabilities, with little margin for unexpected events and requiring complex arrangements to do routine maintenance on critical facilities.”

Issue Number 1.0

1.0 Issue: Project Need and Justification

Request

For the double circuit 500 kV transmission lines in the Province:

a) Please provide the sustained outage rate per kilometer per year for overhead transmission circuits.

b) Please provide a breakdown of the causes of sustained outages for overhead transmission lines.

c) Please provide the average restoration time for overhead transmission lines experiencing a sustained outage.

d) Please provide the momentary outage rate per kilometer per year for overhead transmission circuits.

e) Please provide a breakdown of the causes of momentary outages for overhead transmission lines.

f) Please provide the definitions of sustained outage and momentary outage used in the data supplied in response to the above.

g) What percentage of the sustained outages affecting a 500 kV transmission circuit on a double circuit transmission line causes both circuits on the line to experience sustained outages?

h) What percentage of the momentary outages affecting a 500 kV transmission circuit on a double circuit transmission line causes both circuits on the line to experience momentary outages?

Response

a) Sustained outage rate = .00100821 outages /year/km

Assumptions:

- Outage data covers the period Jan 1990 to Jan 2007
- Common mode outages are included in the assessment

- Outages related to line terminals are excluded
- All outages regardless of their durations are included.

b) The Table below gives the causes of sustained outages to 500 kV circuits on double circuit tower lines from January 1990 to January 2007.

Cause	Number of Outages	% of Total
Terminal equipment defects	48	33.3%
Protection equipment defects	43	29.9%
Line equipment failures – eg. Conductor, insulators or tower	18	12.5%
Maintenance personnel	15	10.4%
Adverse weather (Lightning, Wind, Ice etc.)	14	9.7%
Public – eg tree contact, gunfire	1	0.7%
Forest Fire	1	0.7%
Unknown	4	2.8%
Total Sustained Outages	144	

c) Average restoration time = 38.58285 hour/outage

Assumptions:
- Outage data covers the period Jan 1990 to Jan 2007
- Common mode outages are included in the assessment
- Outages related to line terminals are excluded
- All outages regardless of their durations are included.

d) Momentary outage rate = .00175624 outages/year/km

The same assumptions as above

e) The Table below gives the causes of momentary outages to 500 kV circuits on double circuit tower lines from January 1990 to January 2007.

Cause	Number of Outages	% of Total
Adverse weather – Isolated lightning	22	25.3%
Adverse weather – Severe electrical storm	14	16.1%
Other Adverse weather (Wind, Ice, fog etc.)	13	15.0%
Protection equipment defects	11	12.6%
Maintenance personnel	4	4.6%
Line equipment failures – eg. Conductor, insulators or tower	2	2.3%
Terminal equipment defects	1	1.1%
Unknown	20	23.0%
Total Momentary Outages	87	

f) Momentary or transient line outage is an outage that lasts less than one minute and the line is removed from service and is returned to service by the line protection system (This covers only automatic re-closure events).

Sustained or permanent line outage is an outage that lasts one minute or more and the line is removed from service either automatically (by the protection system) or manually (It does not include automatic re-closure events).

g) The answer to this question is not readily available.

h) The answer to this question is not readily available.

Exhibit No. 18

Pollution Probe INTERROGATORY #18 List 2

Interrogatory

Issue Number: 1.0
Issue: Project Need and Justification

Ref B/Tab 1/Sch 1, page 3, "Other alternatives considered" Please provide the following information:

For the potential use of Bruce area generation rejection schemes, please provide the following requested information or answers:

a) Any and all documents or analyses developed by Hydro One or the OPA concerning the historical and forecasted future use of generation rejection schemes at the Bruce site.

b) What are the historical levels of forced outages on the 500 kV transmission system in the Ontario Southwest Area? Please provide all documentation or studies that address the actual level of forced outages that have been experienced with the transmission system in this region. Please also include both the number and duration of outages by year.

Response

a. Please refer to the response to OEB Staff Interrogatory 1.4 for information regarding the Bruce generation rejection scheme and its historical usage. With respect to forecast future use of the scheme, a forecast is not prepared. However, it is reasonable to assume that usage (i.e., arming of the scheme) will increase over time as generation in the Bruce area increases, in the event the proposed Bruce to Milton line is not built.

b. The historical data pertaining to forced outages on the 500 kV transmission system in Southwestern Ontario is provided in the attached Table 1 and Table 2 as follows. The circuit identifications in these tables refer to circuits' connecting terminal points identified in Exhibit C-3-8.

- Table 1 provides a summary of the overall outage indices for each circuit, including the number of momentary and sustained outages per year; the average rate and duration of such outages per year; average duration of sustained outage in hours per outage per year; and the average circuit unavailability in hours per year.

- Table 2 provides a summary of the outage frequency and duration for each circuit by year. (*Note: For any circuit that did not have an outage in any year, the entry for that year is not shown in the Table 2).*

Table 1: Summary of Outage Indices for 500 KV Circuits in SWO for the Period January 1990 to February 2008

Circuit ID	In Service Date of the Circuit	No. Momentary outages For Circuit	Average Rate of Momentary Outages/year	No. of Sustained Outages for Circuit	Average Rate of Sustained Outages/year	Average Duration of Sustained Outage Hours/Outage/year	Average Circuit Unavailability in hours/year
B562L	Nov 22, 1990	10	.5788	8	.4631	12.1563	5.6292
B563L	Nov 22, 1990	6	.3473	8	.4631	9.0313	4.1821
B569B	Oct 1, 1980	1	.0550	0	0	0	0
M585M	June 22, 1990	6	.3392	11	.6218	8.5667	5.3265
N580M	June 22, 1990	1	.0565	9	.5087	5.2722	2.6820
N581M	Nov 22, 1993	1	.0654	4	.2618	2.1375	.5596
N582L	Aug 22, 1991	2	.1141	4	.2282	25.0083	5.7069
V586M	June 17, 1994	2	.1360	4	.2720	.60	.1632
B560V	June 24, 1994	7	.4767	8	.5447	137.30	74.7873
B561M	July 1, 1980	7	.3853	10	.5504	63.795	35.1128

Notes:

1. Outage data covers the period Jan 1990 to Feb 2008
2. Momentary outages last less than one minute
3. Sustained outages last one minute or more
4. All outages regardless of their durations are considered
5. Circuit unavailability =Average rate of sustain outages x Average duration of sustain outage

Table 2: Summary of Frequency and Duration of Circuits By Year for the Period January 1990 to February 2008

Circuit	Year	Outage	
		Frequency	Duration (Minutes)
B562L	1991	1	1119
	1995	1	6
	1996	2	54
	1997	2	0
	1999	1	11
	2000	1	0
	2003	1	0
	2003	1	4509
	2004	4	126
	2005	2	10
	2006	1	0
	2007	1	0
B563L	1991	1	1229
	1995	3	77
	1999	1	0
	2000	3	0
	2002	1	1
	2003	2	1587
	2004	1	0
	2007	1	1441
	2008	1	0
B569B	1992	1	0
M585M	1990	1	0
	1991	2	1026
	1992	1	66
	1994		0
	1994	2	1690
	1995	1	0
	1999	1	0
	2001	1	4
	2002	3	823
	2003	1	0
	2005	2	779
	2007	1	694

Circuit	Year	Outage	
		Frequency	Duration (Minutes)
N580M	1990	1	158
	1991	2	2
	1994	2	910
	1998	1	1122
	2002	3	645
	2005	1	10
N581M	1997	2	302
	2006	1	0
	2007	2	211
N582L	1991	1	5932
	1998	1	3
	2000	1	0
	2001	2	16
	2003	1	51
V586M	1998	1	0
	2000	1	0
	2002	1	7
	2003	1	65
	2004	1	15
	2008	1	57
B560V	1994	2	1515
	1996	2	24463
	1997	1	0
	1998	2	29
	1999	1	0
	2000	1	114
	2001	2	39411
	2002	1	0
	2004	1	0
	2005	1	0
	2006	1	372
B561M	1991	2	513
	1992	5	2894
	1993	2	1526
	1994	1	0
	1996	1	24392
	1997	1	1491
	1998	2	6480
	2000	1	0
	2004	1	0
	2008	1	981

Exhibit No. 19

Energy Probe INTERROGATORY #10 List 2

Interrogatory

Ref: Exh. B/T 6/S 2
Issue 2.4(b): Have appropriate comparisons been carried out on all reasonable alternatives with respect to reliability and quality of electricity service, including stability and transient stability levels, voltage performance and Loss of Load Expectation projections under normal and post-contingency conditions?

The evidence at Schedule 2 is the final version of the IESO System Impact Assessment Report, dated March 27, 2007. Section 8 is entitled *Reference Load Flow Diagrams with all eight units in-service*. At Page 10, Subsection 8.2 focuses on *Contingency Conditions*.

(a) Please explain how the contingency scenarios analyzed in the System Impact Study were chosen?

(b) Were any contingency scenarios other than the ones cited in the study analyzed? If so please provide the analyses.

(c) How frequently have the contingency scenarios in the System Impact Study actually occurred in the past 20 years?

(d) The study references breaker failure as the precipitating event for two of the contingencies in the study. What sort of events are contemplated that would result in the loss of two 500 kV circuits in the two transmission line contingencies?

Response

a) The *Transmission Design Criteria* defined in Section 5 of *NPCC Document A2: Basic Criteria for Design and Operation of Interconnected Power Systems* (please see the response to Board Staff Interrogatory 3.2 for a link to the above-noted document) require that both stability and acceptable voltages be maintained during and following the most severe of the contingencies listed below:

   a. A permanent three-phase fault on any generator, transmission circuit, transformer or bus section with **normal fault clearing**.

   b. Simultaneous permanent phase-to-ground faults on different phases of each of two adjacent transmission circuits on a multiple circuit tower, with **normal fault clearing**.

c. A permanent phase-to-ground fault on any transmission circuit, transformer, or bus section with **delayed fault clearing**.

d. Loss of any **element** without a fault.

e. A permanent phase-to-ground fault on a circuit breaker with **normal fault clearing**.

f. Simultaneous permanent loss of both poles of a direct current bipolar facility without an AC fault

g. Failure of a circuit breaker to operate when initiated by an SPS following: loss of any **element** without a fault; or a permanent phase-to-ground fault, with **normal fault clearing**, on any transmission circuit, transformer or bus section.

Experience has shown that the loss of the double-circuit line between the Bruce Power Complex and the Milton SS represents the most severe contingency for the area under review. Consequently, although operating limits are derived for all of the contingency conditions defined in the A2-Document, the analysis performed for the purpose of assessing a project's effect on the reliability of the integrated power system is usually confined to the most severe contingency condition. In the case of the Bruce to Milton project the most severe contingency condition is the loss of the double-circuit line between the Bruce Power Complex and the Milton SS, involving circuits B560V & B561M.

b) Since the new Bruce to Milton 500kV line will also involve new terminations on to the 500kV busbar at the Milton SS, the effect of specific breaker-failure conditions that would result in the simultaneous loss of two transmission circuits were analyzed as required by Item g. (above) from the A2-Document.

c) Although the contingency conditions that have been reviewed in the SIA Report occur very rarely, it is the IESO's obligation as a member of NPCC to ensure that the Interconnected Power System is designed and operated in a manner that would ensure that stability and acceptable voltages are maintained during and following the most severe contingency conditions. The frequency with which the contingency conditions occur is not a consideration in the A2-Document.

d) The two breaker failure conditions referred to on Page 14 of the SIA Report could arise as follows:

i. A contingency involving the 500kV circuit B561M, between the Bruce Complex and the Milton SS would normally be cleared (isolated) at the Milton SS through the tripping of breakers KL561 & L61L71 (please refer to Diagram 3 of the Report).

Should breaker L61L71 fail to open for any reason, this would be detected by the breaker-failure protection associated with this particular breaker, and tripping of the breakers associated with the next protection zone would be initiated to isolate the faulted element, B561M. This would entail opening breaker HL573 together with the 'New' breaker associated with the H-busbar at the Milton SS, as well as the breakers associated with circuit M571V at Claireville TS.

The net result of this action would be to remove not only the faulted circuit B561M from service but also circuit M571V.

ii. Similarly, for a contingency involving the 500kV circuit M570V, between the Milton SS and Claireville TS, the faulted element would normally be isolated at the Milton SS by the operation of breakers KL570 & L70L73. A failure of breaker L70L73 to operate would require breaker HL573 at the Milton SS to be tripped via the breaker-failure protection. In addition, the 230kV breakers at Trafalgar TS that are associated with the auto-transformer connected to circuit M573T would also be tripped. (Trafalgar TS is not equipped with any 500kV fault interrupting devices that could isolate the faulted element.)

As before, the net result would be to remove not only the faulted circuit M570V from service, but also circuit M573T, together with the auto-transformer at Trafalgar TS that is directly associated with this circuit.

Since either of these conditions would result in the simultaneous loss of two major circuits, the consequences to the system are more severe and require separate consideration. Wherever possible, the layout of the transformer station is designed to minimise the effect of such breaker-failure conditions by placing the termination of a non-critical (or less critical) circuit adjacent to a critical one.

Exhibit No. 20

Pollution Probe INTERROGATORY #46 List 4

Interrogatory

Ref. Exh. B/T 6/S 5, Appendix 2

Issue Number 2.0
2.0 Issue: Project Alternatives

Request

a) On page 3, it states that 30% series compensation may be used as a stopgap measure to expand transmission capability to accommodate eight Bruce units if approvals for the new 500 kV line are delayed.
   i Please provide a copy of any studies, analyses, results, or reports produced as a result of the IESO's, the OPA's, and/or Hydro One's assessment of series compensation.
   ii Please provide a saved case in PTI-format, compatible with Siemen's PSS/E version 30, for the load flow studies performed by or for Hydro One, the OPA, and/or the IESO in studying the use of 30% series compensation.

b) On page 3, it states that interim measures, such as generation rejection and series compensation are not alternatives to the long-term solution since they increase the risk to the security and reliability of the power system.
   i Please provide a copy of any studies, analyses, results, or reports produced as a result of the IESO's, the OPA's and/or Hydro One's assessment of generation rejection.
   ii ii. Please describe how the use of series compensation increases the risk to the security and reliability of the power system, and please also provide a copy of any letters, reports, studies, analyses, etc. which support this opinion.
   iii Please describe how the use of generation rejection increases the risk to the security and reliability of the power system, and please also provide a copy of any letters, reports, studies, analyses, etc. which support this opinion.

c) On page 3, it states that Hydro One has expressed concern regarding the system and equipment risks of using series compensation. Please provide a copy of the document(s) in which these concerns are expressed.

d) On page 3, it states that the OPA will retain third party experts to undertake a due diligence study to assess the suitability and risks associated with the use of series compensation for this application.
   i Please describe the status of this due diligence study.
   ii Please provide a copy of any reports, analyses, recommendations etc. that have been prepared as a result of or are related to this due

diligence study.

e) On page 3, it states that the use of generation rejection is subject to NPCC approval.

i Has NPCC ever rejected a request to use generation rejection in the Province? If yes, please provide a copy of the request(s) and the NPCC response(s) regarding the request(s).

ii Has NPCC ever rejected a request to use generation rejection for generation located in the Bruce Complex? If yes, please provide a copy of the request(s) and the NPCC response(s) regarding the request(s).

iii Please describe if generation rejection has ever been used for generation located in the Bruce Complex. If yes, please provide a copy of the request and the NPCC response regarding each such use of generation rejection.

Response

a) i. Please refer to the response to Pappas Interrogatories 1 and 6.

ii. Please refer to the letter from Hydro One to the Board dated March 13, 2008, at page 5, with respect to paragraph 3 of Procedural Order 5. To better utilize the resources available at the IESO and to obtain the maximum benefit from those resources, the IESO has proposed that it should perform a reasonable number of studies for Pollution Probe, at their specific direction. The results of these studies would then be provided to Pollution Probe in a format suitable for filing as evidence.

b) i. and ii.

Please refer to the responses to Board Staff Interrogatory 1.4, Saugeen Interrogatory 11 and Pappas Interrogatory 6 for information regarding generation rejection provided by Hydro One and OPA.

The IESO has not published any formal studies that assess generation rejection. However, the following analysis demonstrates that, to comply with the NPCC criteria as set out in Document A2, "Basic Criteria for Design and Operation of Interconnected Power Systems," in the absence of a new 500kV line from the Bruce Complex to Milton TS, the maximum amount of generation capacity that could be dispatched at the Bruce Complex would be seven units. Clause 6.3 of Document A2 is quoted below:

6.3 Post Contingency Operation

Immediately after the occurrence of a **contingency**, the status of the **bulk power system** must be assessed and transfer levels must be adjusted, if necessary, to prepare for the next **contingency**. If the readjustment of generation, load resources, phase angle regulators, and direct current facilities, is not adequate to restore the system to a secure state, then other measures such as voltage reduction and shedding of firm load may be required. System adjustments shall be completed as quickly as possible, but in all cases within 30 minutes after the occurrence of the **contingency**.

Voltage reduction need not be initiated and firm load need not be shed to observe a post-**contingency** loading requirement until the **contingency** occurs, provided that adequate response time for this action is available after the **contingency** occurs and other measures will maintain post-**contingency** loadings within **applicable emergency limits**.

Emergency measures, including the pre-contingency disconnection of **firm load** if necessary, must be implemented to limit transfers to within the requirements of 6.2 above.

Clause 6.2 notably states:

Stability of the **bulk power system** shall be maintained during and following the most severe of the following **contingencies**, and **with due regard to reclosing**:

a. A permanent three-phase fault on any generator, transmission circuit, transformer or bus section, with **normal fault clearing**.

b. The loss of any **element** without a fault.

Immediately following the most severe of these **contingencies**, voltages, line and equipment loadings will be within **applicable emergency limits**.

The following describes how the application of the A2 criteria would affect the operation of the system without a new 500kV line from the Bruce Complex, and using generation rejection.

Diagram 1 (attached) shows the results of a load flow study with 30% series compensation installed on the Bruce x Longwood and the Longwood x Nanticoke 500kV circuits. Seven Bruce units are in-service, together with the 675MW of committed wind-turbine projects.

The transfer across the Negative-BLIP Interface has been adjusted to be approximately 500MW (the actual transfer is 576MW).

Following a contingency involving the Longwood x Nanticoke 500kV circuit, N582L, the system would then have to be re-prepared for the next contingency. The internal resources available to the IESO for the required adjustments would total approximately 900MW. This represents the 10-minute Operating Reserve that has to be maintained on the system to cater for the potential loss of one 900MW generating unit at Darlington GS.

As shown in Diagram 2 (attached), this 900MW has been used to back-down the 200MW Leader Wind Farm and to reduce the transfers across the Negative-BLIP Interface. As shown, this action has resulted in a Positive-BLIP transfer of approximately 100MW.

Comparing Diagrams 1 and 2 demonstrates that there is no overall increase in transmission losses following the re-preparation of the system.

Diagram 3 (attached) shows the results of a subsequent contingency involving the 500kV double-circuit line between the Bruce Complex and Milton TS.

In response to this contingency, two of the generating units at the Bruce Complex would need to be rejected. It has also been assumed that approximately 15% of the resulting resource deficiency (1600 MW) would be automatically compensated through the response of the governors on the generating units in Ontario. The combined output from the units at Darlington GS has been increased by 250 MW as a proxy for this action.

The post-contingency flows on the 230 kV circuits between Longwood TS and Buchanan TS and also from the Bruce Complex are shown to be at, or marginally below, their respective thermal limits.

Comparing Diagrams 2 and 3 shows a net increase of approximately 1520 MW in the transfers into Ontario via the Interconnections with New York and Michigan. A further increase of approximately 80 MW is shown in the transfer across the Flow South Interface, representing increased transfers via the Interconnections with Manitoba and Minnesota. The net effect of tripping the two units at Bruce GS in response to a double-circuit contingency involving the Bruce to Milton line would be an increase of approximately 1600 MW in the transfers via the Interconnections with our neighbouring utilities. Since this would exceed the agreed limit of 1500 MW, corrective action would therefore need to be taken.

These studies effectively demonstrate that to comply with the A2 criteria and in the absence of a new 500 kV line from the Bruce Complex to the Milton SS, the maximum amount of generation capacity that could be dispatched at the Bruce Complex would be seven units. In addition, with seven Bruce units dispatched together with all of the committed wind-turbine projects, the transfers across the Negative-BLIP Interface would need be limited to a maximum of approximately 500MW.

iii. Please see the response to Board Staff Interrogatory 3.2.

c) Hydro One's concerns were included in comments provided to the OPA in response to its Transmission Discussion Paper #5, as part of the stakeholder consultation process of the IPSP. Comments made in respect of the long-term use of the interim measures on the Bruce to Milton Transmission Project were stated as follows:

Concerns about Long-Term Use of Interim Measures for the Bruce Transmission system

While it is preferable to have the new 500 kV transmission line between the Bruce area and the GTA constructed as soon as possible, as noted in the Transmission Document, it is unlikely that the new line will be in-service until late 2011. Therefore, the Transmission Document proposes to use near-term and medium-term interim power system measures such as the installation of significant amounts of shunt capacitor banks and static var compensation (SVC); provision for generation rejection equivalent to up to two units at the Bruce Power complex; and the installation of 30 % series compensation on the Bruce to Longwood to Nanticoke 500 kV circuits providing OPA studies conclude it is consistent with good utility practice.

Hydro One recommends that reliance on these interim measure should be limited to as short a time period as possible and the need for these measures should be obviated in the longer term by building a new transmission line out of the Bruce area This recommendation is based on significant concerns about the use of the interim measures from the perspective of the difficulties in operation and maintenance of the transmission system, potential for increased occurrences of transmission congestion, and the reduced reliability of the power system. Some of these concerns are summarized below.

Use of Series Compensation

- The installation of series compensation in SWO would represent a unique application of this technology since it would result in series compensation being used on circuits connected to more than 6,000 MW of mostly nuclear generation in the most critical part of the interconnected North American power system.

- Hydro One is cognizant of the fact that series compensation is a proven transmission technology outside Ontario. However, Hydro One's past experience is that newly installed products or technologies are prone to suffering unexpected malfunctions or mis-operations during their initial deployment due to unexpected design or manufacturing deficiencies. Such "teething pains" have resulted in prolonged equipment unavailability and/or adverse system impacts. These outcomes, coupled with the substantial reliability and commercial consequences of the series compensation performing poorly, unique power system characteristics, protection implications, and concerns about system operability, necessitate the need for due diligence considerations for this option, in the context of its utilization in Southwestern Ontario, as indicated in the Transmission Document.

d) i. The due diligence report on the use of series capacitors for this project is complete.
Please refer to the response to Pappas Interrogatory 6.

ii. Please refer to the response to Pappas Interrogatory 6.

e) i. Generation rejection schemes, like other forms of Special Protection Systems, must go through an NPCC approval process before being employed. During this process, the IESO must demonstrate that the generation rejection scheme allows for proper system operation, and that the risks of improper system operation are either acceptably low or that the consequences of improper operation are acceptable. Once a Special Protection System has been approved for use by the NPCC, it is the responsibility of the IESO to ensure the SPS is judiciously used.

ii. The NPCC has never rejected a request to use generation rejection for generation located in the Bruce Complex.

iii. Requests are not made to the NPCC to arm generation rejection – as explained in part i) above it is the responsibility of the IESO to ensure the SPS is judiciously used. The Bruce Special Protection System (BSPS), whose main feature enables the arming of Bruce units for rejection, has been heavily used in the recent past. During the course of the past three years the BSPS has been armed to reject at least one unit for the Bruce-Milton, Bruce-Claireville 500 kV double circuit contingency for between 4,300 to 5,500 hours per year. In this same period, two units have, on average, been armed for approximately 1,100 hours per year. Without arming, generation would have become congested during this period. The commitment to put more generation in the Bruce Area will increase arming until transmission enhancements are made. Arming is already at its maximum amount during a significant portion of the year.

Although the arming of Bruce units for generation rejection has been the rule rather than the exception in the recent past, the occurrences of contingencies that trigger generation rejection are relatively uncommon. Most of the time, the most limiting contingency for the Bruce Complex is the loss of the Bruce-Milton-Claireville line. This contingency last occurred May 31, 1985 as a result of damaging tornados that swept across Central Ontario. The Bruce Special Protection System tripped Bruce units G1, G3 and G5 (net 2175 MW) and 737MW of pre-selected customer load. Primary demand at this time was 14234 MW.

Exhibit No. 21

REQUIREMENTS

Ontario Resource and Transmission Assessment Criteria

Issue 5.0

This document is to be used to evaluate long-term system *adequacy* and *connection assessments*

3.4 Permissible Control Actions

Following the occurrence of a contingency, the following control actions may be used to respect the loading, voltage decline, and stability limits referenced in this document:

- Generation Redispatch
- Automatic tripping of generation (generation rejection)
- Trip circuits open to change flow distributions
- Trip or redispatch *dispatchable loads*
- Switch reactors and/or capacitors out (switching in of capacitors in locations that are especially sensitive to voltage changes is to be done only in such a manner as to ensure minimal impact on customers, e.g., using independent pole operation (IPO) breakers)
- Operate phase shifters

In addition to the above control actions, automatic or manual tripping of *non-dispatchable load* may be considered for certain contingencies with one or more transmission elements out-of-service. Generally, *facilities* for the automatic tripping of load will only be acceptable as a stop gap measure to increase the power transfer capability across a bulk transmission interface to cope with temporary deficiencies.

The control actions that are permissible are shown below:

Permissible Control Actions Following Contingency

System Condition Prior to Contingency	Permissible Control Actions Following Contingency
All elements in service	• Generation Redispatch • Load Redispatch • Generation Rejection • Capacitor Switching • Reactor Switching • Open circuits to change flow distributions
One or more transmission elements out of service	• Generation redispatch including transactions • Generation Rejection • Capacitor Switching • Reactor Switching • Open circuits to change flow distributions • Load Rejection

3.4.1 Special Protection System

A *special protection system* (*SPS*) is defined as a protection system designed to detect abnormal system conditions and take corrective action(s) other than the isolation of faulted elements. Such action(s) may include changes in load, generation, or system configuration to maintain system stability, acceptable voltages or power flows. The *NPCC* A-02 criteria provide for the use of a *SPS* under normal and *emergency* conditions.

A *SPS* shall be used judiciously and when employed, shall be installed consistent with good system design and operating policy. A *SPS* associated with the bulk power system may be planned to provide protection for infrequent contingencies, for temporary conditions such as project delays, for unusual combinations of system demand and outages, or to preserve system integrity in the event of severe outages or extreme contingencies. The reliance upon a *NPCC* type I *SPS* for *NPCC* A-2 design criteria contingencies with all transmission elements in service must be reserved only for transition periods while new transmission reinforcements are being brought into service. A *SPS* associated with the non-bulk portion of the power system may be planned to provide protection for a wider range of circumstances than a *SPS* associated with the bulk system.

The decision to employ a *SPS* shall take into account the complexity of the scheme and the consequences of correct or incorrect operation as well as its benefits. The requirements of *SPSs* are defined in *NPCC* criteria A-05, and in NPCC criteria A-11, "Special Protection System Criteria". With all transmission elements in service, continued reliance on a *SPS* is a trigger for considering additional transmission.

A *SPS* proposed in a *connection assessment* must have full redundancy and separation of the communication channels, and must satisfy the requirements of the *NPCC* Type I *SPS* criteria to be considered by the *IESO*.

Automatic Tripping of Generation (Generation Rejection)

Automatic tripping of generation via Generation Rejection Schemes (G/R) is an acceptable post-contingency response in limited circumstances as specified below in section 7.3, Control Action Criteria. Arming of G/R may be acceptable for selected contingencies provided the G/R corrects a *security* violation and results in an acceptable operating state.

– End of Section –

7.2 Load Restoration Criteria

The *IESO* has established load restoration criteria for high voltage supply to a *transmission customer*. The load restoration criteria below are established so that satisfying the restoration times below will lead to an acceptable set of *facilities* consistent with the amount of load affected.

The *transmission system* must be planned such that, following design criteria contingencies on the *transmission system*, affected loads can be restored within the restoration times listed below:

a. All load must be restored within approximately 8 hours.

b. When the amount of load interrupted is greater than 150MW, the amount of load in excess of 150MW must be restored within approximately 4 hours.

c. When the amount of load interrupted is greater than 250MW, the amount of load in excess of 250MW must be restored within 30 minutes.

These approximate restoration times are intended for locations that are near staffed centres. In more remote locations, restoration times should be commensurate with travel times and accessibility.

7.3 Control Action Criteria

The deployment of control actions and *special protection systems* must not result in material adverse effects on the bulk system.

The *transmission system* may be planned such that control actions such as generation re-dispatch, reactor and capacitor switching, adjustments to phase-shifter and HVdc pole flow, and changes to inter-Area transactions may be judiciously employed following contingencies to restore the power system to a secure state.

The reliance upon a *special protection system* must be reserved only for exceptional circumstances, such as to provide protection for infrequent contingencies, temporary conditions such as project delays, unusual combinations of system *demand* and *outages*, or to preserve system integrity in the event of severe *outages* or extreme contingencies.

Transmission expansion plans for areas that may have a material adverse effect on the interconnected bulk power system must not rely on *NPCC* Type I *special protection systems* with all planned transmission *facilities* in service.

7.4 Application of Restoration Criteria

Where a need is identified, for example via the *IESO's* outlooks or via the OPA's IPSP, *market participants* and the applicable *transmitter* will be notified of the need for a deliverability study.

Transmission customers and *transmitters* can consider each case separately taking into account the probability of the contingency, frequency of occurrence, length of repair time, the extent of hardship caused and cost. The *transmission customer* and *transmitter* may agree on higher or lower levels of *reliability* for technical, economic, safety and environmental reasons provided the bulk power system adheres to *NERC* and *NPCC* standards.

Exhibit No. 22

Saugeen Ojibway First Nations INTERROGATORY #11 List 1

Interrogatory

Ref. Exh. *B/T 6/S* 2, Exh. *B/T 6/S 5/*Appendix 5, other studies performed by the IESO
Issue Number: 3.3

> 3.3 Issue: If these proposed near term and interim measures could be utilized for a longer period than proposed, could they (or some combination of similar measures) be considered an alternative to the double circuit 500 kV transmission line for which Hydro One has applied?

Request

Please provide detailed descriptions and studies of the existing GR scheme that exists at the Bruce substation and all enhancements of the existing GR scheme that have been considered by IESO, Hydro One or OPA. Please provide a copy of all documents related to, arising from or used in connection with implementing the existing GR scheme and all enhancements to that GR scheme that have been considered, including, but not limited to, all communications with the Northeast Power Coordinating Council ("NPCC") with respect to the GR Schemes compliance with NPCC's SPS procedures and requirements.

Response

Please refer to response to Board Staff Interrogatory 1.4(v) for information regarding the Bruce GR scheme.

The original Bruce Special Protection System (“SPS”) was classified by the NPCC over twenty years ago and records relating to those matters are not available. The existing Bruce SPS is classified by NPCC as a type I SPS. In the most recent comprehensive transmission review (which took place in 2007 and was undertaken to demonstrate compliance with NPCC criteria) the IESO reported to NPCC that the SPS is expected to continue to require a type I classification. The report compiled in respect of this review is a non-public confidential document as it relates to the ongoing protection and security of the Ontario transmission grid.

The Bruce SPS addresses specific post-contingency connectivities (i.e., configurations) of the transmission system, and initiates appropriate operational responses, including the rejection of generating units at the Bruce Complex.

A revised functional specification for the Bruce SPS is currently being prepared by the IESO in collaboration with Hydro One. This will increase the scope of the Bruce SPS beyond that which was detailed in Section 14 of the IESOs SIA Report (Ref: IESO_REP_0299, dated 11th April 2006).

The preliminary list of the contingencies that are to be covered by the enhanced Bruce SPS is as follows:

500kV Circuits

1. B569B
2. B560V
3. B561M
4. B560V & B561M
5. B x M new circuit 1
6. B x M new circuit 2
7. B x M new circuit 1 & B x M new circuit 2
8. B562L
9. B563L
10. B562L & B563L
11. B561M & B562L
12. B560V & B563L
13. M585L
14. V586M
15. M585L & V586M

500kV Circuits (Continued)

16. M570V
17. M571V
18. M570V & M571V
19. B560V & M571V
20. N582L
21. N580M
22. N581M
23. Loss of Bruce x Milton 500kV ROW

230kV Circuits

1. B22D
2. B23D
3. B22D & B23D
4. B4V
5. B5V
6. B4V & B5V

And the range of responses that is required are as follows:

Responses

1. Trip Bruce ‘A’ Unit G1

2. Trip Bruce ‘A’ Unit G2

3. Trip Bruce ‘A’ Unit G3

4. Trip Bruce ‘A’ Unit G4

5. Trip Bruce ‘B’ Unit G5

6. Trip Bruce ‘B’ Unit G6

7. Trip Bruce ‘B’ Unit G7

8. Trip Bruce ‘B’ Unit G8

9. Trip Reactor R25 at Bruce ‘A’

10. Trip Reactor R27 at Bruce ‘A’

11. Trip Reactor R28 at Bruce ‘A’

12. Trip Reactor R3 at Longwood TS

13. Trip Reactor R4 at Longwood TS

14. Trip Reactor R5 at Longwood TS

15. Trip Reactor R6 at Longwood TS

16. Trip Reactor R7 at Longwood TS

Responses (Continued)

16. Cross-trip 115kV circuit S2S

17. Trip Leader Wind Project

18. Trip Melancthon Wind Project

19. Trip Ripley Wind Project

20. Trip Kingbridge II Wind Project

21. Trip Lake Erie Wind Project

22. Trip All Wind Project

23. Switch Capacitor 1 at Nanticoke

24. Switch Capacitor 2 at Nanticoke

25. Switch Capacitor 3 at Nanticoke

26. Switch Capacitor 4 at Nanticoke

26. Switch Capacitor 5 at Nanticoke

27. Switch Capacitor 1 at Detweiler

28. Switch Capacitor 2 at Detweiler

NPCC registration and approval will be sought for the deployment of the enhanced Bruce SPS scheme upon completion of the design and IESO system impact analysis.

10.1.1 Bruce Special Protection System

The Bruce Complex consists of eight nuclear units, totaling approximately 7,000 MW of capacity, connected to the power system through two 500 kV lines (two circuits from Bruce to Milton TS, one of which continues on to Claireville and two circuits from Bruce to Longwood TS) and six 230 kV circuits. Three 750 MVA autotransformers connect the 500 and 230 systems at Bruce. The 500 kV line to Milton runs primarily West to East, while the 500 kV line to Longwood runs North to South.

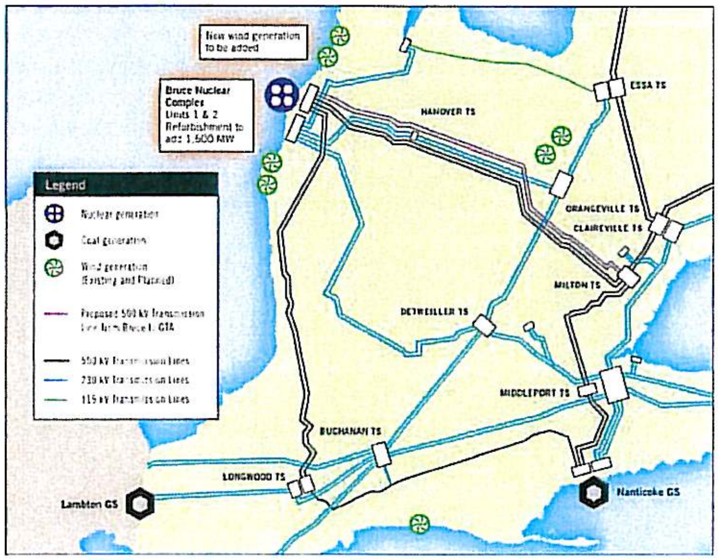
The Bruce SPS allows for detection of certain power system events and the immediate disconnection of up to 4 Bruce units and up to 1,500 MW of load. However, the use of this SPS will be limited to the arming of no more than 2 generating units; no load rejection is planned to be armed.

An agreement has been reached between the Ontario Government and Bruce Power Inc. for the return to service of Bruce A unit 2 and unit 1 in 2009 and 2010 respectively. In addition, contracts have been awarded under the government of Ontario Renewables I & II RFPs for the incorporation of wind-turbine generation capacity totaling to 1,370 MW. Of the 1,370 MW about 725 MW is to be installed into the part of the system that has a direct impact on the Bruce Complex. Therefore, the total capacity from the Bruce Complex can be as high as 7,700 MW.

In order to accommodate the total generation from the Bruce Complex, Hydro One has submitted an application to the Ontario Energy Board requesting for a leave to construct a new 500 kV double-circuits line from Bruce Power Facility to the Milton Transformer Station. The new line is expected to be in-service by the winter of 2011 to 2012.

The Bruce SPS will remain as a Type I SPS and will only be required during periods when transmission elements are out of service.

Figure 10: Projected Transmission Corridor Bruce-Milton



The simulations performed in this comprehensive review with the wind generation and all eight Bruce units at maximum show that for all normal and extreme contingencies involving the Bruce facility, the system remains stable and well damped without the Bruce SPS operation. These results indicate that with all eight Bruce units in-service together with the wind generation in the area, the Bruce SPS will not be needed to reject load or nuclear generation units provided that the proposed new double-circuits line is in-service.

Test results from the System Impact Assessment (SIA) report "For the incorporation of a new 500kV double-circuits line between the Bruce Complex & Milton TS" show a similar result and conclusion. The SIA report recommended that the Bruce SPS be expanded to allow for generation rejection to be initiated from the additional recognized contingency from the new 500 kV circuits during periods when transmission elements are out of service. Additional information and test results on the proposed 500 kV circuits can be obtained from the IESO website (report No. 2006-250) available at http://www.ieso.ca/imoweb/connassess/caa_StatusSummary-2.asp

In conclusion, the Bruce SPS is expected to remain as a Type I SPS. Test results demonstrate that the BSPS will only be required for a small percentage of time to avoid bottling generation under multiple outage conditions, or possibly to mitigate the effect of extreme contingencies. Classification of the Bruce SPS will be completed closer to the in-service date of the proposed two new 500 kV circuits between Bruce and Milton.

Exhibit No. 23

Pollution Probe INTERROGATORY #39 List 4

Interrogatory

Ref. Technical Conference Panel One (Oct 15, 2007) slide presentation, slide 31 of 43.

Issue Number 2.0
2.0 Issue: Project Alternatives

Request

The slide shows eight options considered, including the proposed transmission line from Bruce to Milton, and five screening categories:

a) For each of the options listed, please provide a description of the facilities included in each option.
b) For each of the options listed, please provide a description of the total transmission capability in MW away from Bruce with no contingencies.
c) For each of the options listed, please provide a description of the total transmission capability in MW away from Bruce with the worst single contingency, and a description of that contingency.
d) For the capacity determinations addressed in (b) and (c) above, please describe and provide the assumptions for generation dispatch and system imports that were used in these determinations.
e) For each of the options listed, please describe the effects on other transmission paths that were considered.
f) For each of the options listed, please provide total cost for the option, a cost breakdown for the option, and cost workpapers.
g) For each of the options listed, please describe the land use characteristics that were considered.

Response

a) Descriptions of the facilities comprising each option above, other than series compensation, are presented in the application (Exhibit B Tab 3 Schedule 1 at pages 4-6). Series compensation was described during the Technical Conference (please refer to the Day 1 transcript at page 26). Generally, series compensation on the three 500kV circuits between Longwood and Nanticoke, and Bruce to Longwood would include facilities situated at the midpoint of those facilities at a new station site. The facilities would comprise an insulated platform, capacitor banks, protective equipment, switches and breakers.

b) Assuming no contingencies, the total transmission capabilities of all options considered are greater than those tabulated in response c) below. For planning and operating purposes, the Bruce transmission system is tested for the loss of a double circuit line, as is required by NPCC and IESO planning and reliability standards. It is therefore inappropriate to consider capability with a "no contingencies" assumption.

c) The total transmission capabilities in MW for the options considered as well as the limiting contingencies are shown in the table below. The options involving HVDC connections have not been studied by the IESO, but the IESO is unaware of any technical reason that HVDC connections could not increase transfer capability to the level required, assuming that the necessary facilities are constructed.

d) For each of the options studied by the IESO, the assumptions for generation dispatch and system imports are tabulated below.

e) For each of the options studied by the IESO, voltage stability, transient stability and thermal effects were considered. The voltage stability effects were found to be the most limiting.

f) **Series Capacitors on 500 kV line**

- Two new station sites on existing transmission corridor
- Three new 500 kV series capacitor installations along with protective equipment and 500 kV bypass breakers
- Changes to existing circuit protections
- $97M

Bruce x Essa 500 kV line

- A 187 km 500 kV 2-circuit transmission line from Bruce GS to Essa TS
- Circuit termination equipment at each of Bruce A TS, Bruce B SS, and Essa TS for two circuits along with new 500 kV circuit breakers
- New teleprotection equipment to protect the new circuits
- $635M – Essentially the same as the Bruce x Milton alternative

Bruce x Longwood x Middleport 500 kV line

- A 187 km 500 kV 2-circuit transmission line from Bruce GS to Longwood TS
- A 150 km 500 kV 2-circuit transmission line from Longwood TS to Middleport TS.
- Circuit termination equipment at each of Bruce A TS, Bruce B SS, Longwood TS for three circuits and Middleport TS along with new 500 kV circuit breakers at each location
- New teleprotection equipment to protect the new circuits
- $1,070M ($3 M/km + $20M per circuit termination)

HVDC Lite Cable(s) from Bruce to Milton

- Underground cable(s) with sufficient capacity for 3000 MW between Bruce and Milton (176 km)
- HVDC lite converter stations at both Bruce x Milton sufficient for 3000 MW capacity complete with transformers. Since current technology support 500 MW per pair, six pairs of converter stations and 6 sets of underground cable circuits would be required
- 500 kV termination equipment at Bruce A TS, Bruce B SS and Milton SS suitable for 6 sets of converter pairs
- New teleprotection equipment to protect the new equipment
- $1.5 - $2.0 billion

HVDC 500 kV line from Bruce x Milton

- A 176 km 450 kV HVDC bipolar transmission line from Bruce B SS to Milton SS
- HVDC converter equipment located at both Bruce B SS and Milton SS with 3000 MW capacity complete with transformers and filters
- 500 kV termination equipment at Bruce B SS for two new positions and Milton SS for two positions
- New teleprotection equipment to protect the new equipment
- $1.5 - $2.0 billion

Bruce x Kleinburg x Claireville 500 kV line

- A 189 500 kV 2-circuit transmission line from Bruce GS to Kleinburg TS including approximately 50 km of new right-of-way from approximately Colebeck Junction to a location near Schomberg Ontario
- Circuit termination equipment at each of Bruce A TS, Bruce B SS, and Kleinburg TS for two circuits along with new 500 kV circuit breakers
- Two new 500/203 kV 750 MVA autotransformers at Kleinburg TS
- Four new 230 kV circuit terminations at Kleinburg TS
- A new 5 km long 230 kV 2 circuit line from Kleinburg TS to the existing B82V/B83V 230 kV line near Kleinburg
- New teleprotection equipment to protect the new circuits

- $750M ($3 M/km + $20M per circuit termination +$100 M for modifications to Kleinburg TS)

Bruce x Crieff 500 kV line

- The establishment of a new 500/230 kV TS, Crieff TS south of Guelph near the Highway 401 and Highway 6 interchange with two 500/230 kV autotransformers and a 20 km two circuit 20 kV line from Crieff TS to Preston TS
- A 150 500 kV 2-circuit transmission line from Bruce GS to Crieff TS following the existing Bruce x Milton right-of-way to Hanover TS, the Hanover TS to Detweiler 115 kV right-of-way (D10H) and a new approx 30 km right-of-way from north of Guelph to Crieff TS
- Circuit termination equipment at each of Bruce A TS, Bruce B SS, and Crieff TS for two circuits along with new 500 kV circuit breakers
- New teleprotection equipment to protect the new circuits
- $700M ($3 M/km + $20M per circuit termination +$100 M to establish Crieff TS + $20M property + $50M for new line to Preston TS)

Bruce x Milton 500 kV line

- A 176 km 500 kV 2-circuit transmission line from Bruce GS to Milton SS
- Circuit termination equipment at each of Bruce A TS, Bruce B SS, and Milton SS for two circuits along with new 500 kV circuit breakers
- New teleprotection equipment to protect the new circuits
- $635M

g) The land use characteristics of the transmission options listed in slide 31 of 43 (Technical Conference Panel One presentation, October 15, 2007) are similar in that all of the options traverse or occupy primarily rural and agricultural lands.

Five options (Bruce to Milton, Bruce to Essa, Bruce to Longwood to Middleport, HVDC, HVDC-lite) would be situated on an existing transmission corridor or a widened existing transmission corridor. These options are consistent with the 2005 Provincial Policy Statement (Exhibit B, Tab 6, Schedule 5, Appendix 13).

Two options (Bruce to Kleinburg, Bruce to Crieff) would be situated in part on a widened existing corridor and in part on a new or “greenfield” transmission corridor. The series capacitors option would likely be situated on rural or agricultural lands close to and possibly abutting existing transmission corridors.

h) The losses on the existing system are approximately 1355 MW with 8 Bruce units in service (per diagram 4 of the SIA). The losses for each of the alternatives are tabulated below.

	Bruce to Milton 500 kV line
No contingency	Not limiting
Capability with worst contingency	8160 MW
Worst single contingency	Loss of Bruce x Milton/Claireville circuits
Generation dispatch	- 8 Bruce units - 725 MW Committed Bruce area wind generation - 4 Lambton units - No Nanticoke
System imports	1500 MW from Michigan
System Losses	1239 MW

	Series Capacitors on 500 kV lines	Bruce to Essa 500 kV line	Bruce to Longwood to Middleport 500 kV line	Bruce to Kleinburg to Claireville 500 kV line	Bruce to Crieff TS 500 kV line
No contingency	Not limiting	Not limiting	Not limiting	Not limiting	Not limiting
Capability with worst contingency with respect to the Bruce to Milton 500 kV alternative	Δ -1834 MW*	Δ -1196 MW	Δ -1139 MW	Δ -29 MW	Δ –656 MW
Worst single contingency	Loss of Bruce x Milton/Claireville circuits	Loss of Bruce x Milton/Claireville circuits	Loss of Bruce x Milton/Claireville circuits	Loss of Bruce x Milton/Claireville circuits	Loss of both Crieff x Milton/Claireville circuits
Generation dispatch	- 7 Bruce units - 725 MW wind - No Lambton - No Nanticoke	- 8 Bruce units - 725 MW wind - 4 Lambton units - No Nanticoke	- 8 Bruce units - 725 MW wind - 4 Lambton units - No Nanticoke	- 8 Bruce units - 725 MW wind - 4 Lambton units - No Nanticoke	- 8 Bruce units - 725 MW wind - 4 Lambton units - No Nanticoke
System imports	1500 MW from Michigan	1500 MW from Michigan	1500 MW from Michigan	1500 MW from Michigan	1500 MW from Michigan
System Losses	795 MW*/ 1368MW	1277 MW	1283 MW	1238 MW	1242 MW
* Study conditions for this option are different than those studied for the alternatives to the Bruce to Milton 500 kV line.					

Exhibit No. 24

Saugeen Ojibway First Nations INTERROGATORY #9 List 1

Interrogatory

Ref. Exh. *B/T 6/S* 2, Exh. *BIT 6/S* 5/Appendix 5, other studies performed by the IESO
Issue Number: 3.3
3.3 Issue: If these proposed near term and interim measures could be utilized for a longer period than proposed, could they (or some combination of similar measures) be considered an alternative to the double circuit 500 kV transmission line for which Hydro One has applied?

Request

Please provide all studies (by the IESO or others) that support the claim that generation rejection ("OR") of up to two Bruce units will increase the effective transfer capability out of Bruce to about 6,700 MW, as stated in Exhibit B, Tab 6, Schedule 5, Appendix 5 at page 51 (Ontario IPSP, Discussion Paper 5: Transmission).

Response

When the IPSP Discussion Paper was being prepared, a transfer capability from the Bruce Area of 6700MW was initially considered achievable. This was based on rejecting or being able to reject up to two units at the Bruce Complex while respecting an NPCC-IESO generation deficiency limit of 1500MW, following a contingency, for the subsequent transfers into Ontario from neighbouring jurisdictions to compensate for the resulting resource deficiency.

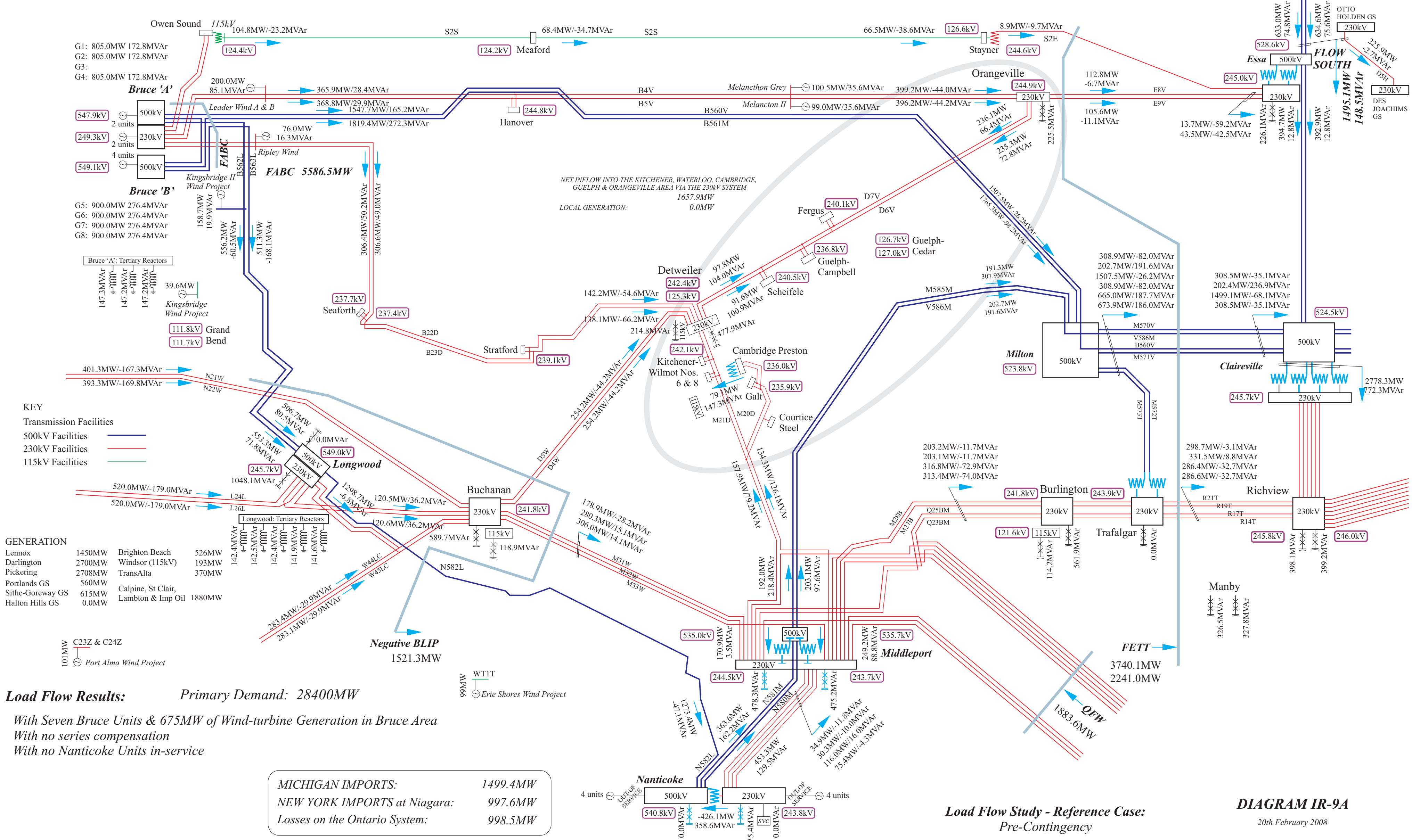
Subsequent analysis has shown that, following the loss of the 500kV double-circuit line between the Bruce Complex & Milton TS, the transmission losses on the system would increase by between 300MW & 400MW. In addition, in order to respect the thermal ratings of circuits B4V & B5V, between the Bruce Complex & Orangeville TS, the 400MW of wind-turbine projects that are connected to circuits B4V & B5V, would have to be rejected.

After taking account of the increased losses and the rejected wind-turbine generation, the maximum amount of generation that could be rejected at the Bruce Complex would therefore need to be restricted to a single unit.

Following the completion of the interim measures, the maximum amount of generation capacity that could therefore be accommodated within the Bruce area if post-contingency generation rejection of one Bruce unit and the 400MW of wind-turbine capacity were to be used, would total 6325MW, consisting of:

Seven units at the Bruce Complex:	Combined Capacity	5650MW (net)
Committed wind-turbine projects in the Bruce area:	Combined capacity	675MW

The results from the analysis supporting this transfer capability have been summarised in the attached Diagrams A & B for the pre- and post-contingency conditions, respectively.


Owen Sound
Meaford
Stayner
Hanover
Orangeville
Essa
FLOW SOUTH
1495.1MW
148.5MVAr
OTTO HOLDEN GS
DES JOACHIMS GS
Bruce 'A'
G1: 805.0MW 172.8MVAr
G2: 805.0MW 172.8MVAr
G3:
G4: 805.0MW 172.8MVAr
Bruce 'B'
G5: 900.0MW 276.4MVAr
G6: 900.0MW 276.4MVAr
G7: 900.0MW 276.4MVAr
G8: 900.0MW 276.4MVAr
Bruce 'A': Tertiary Reactors
Leader Wind A & B
Ripley Wind
Kingsbridge II Wind Project
Kingsbridge Wind Project
FABC
FABC 5586.5MW
Melancthon Grey
Melancthon II
NET INFLOW INTO THE KITCHENER, WATERLOO, CAMBRIDGE, GUELPH & ORANGEVILLE AREA VIA THE 230kV SYSTEM
1657.9MW
LOCAL GENERATION: 0.0MW
Fergus
Guelph-Cedar
Guelph-Campbell
Scheifele
Detweiler
Seaforth
Stratford
Grand Bend
Kitchener-Wilmot Nos. 6 & 8
Cambridge Preston
Galt
Courtice Steel
Milton
Claireville
Longwood
Longwood: Tertiary Reactors
Buchanan
Burlington
Trafalgar
Richview
Manby
Middleport
Nanticoke
Negative BLIP
1521.3MW
FETT
3740.1MW
2241.0MW
QFW
1883.6MW
KEY
Transmission Facilities
500kV Facilities
230kV Facilities
115kV Facilities
GENERATION
Lennox 1450MW
Darlington 2700MW
Pickering 2708MW
Portlands GS 560MW
Sithe-Goreway GS 615MW
Halton Hills GS 0.0MW
Brighton Beach 526MW
Windsor (115kV) 193MW
TransAlta 370MW
Calpine, St Clair, Lambton & Imp Oil 1880MW
C23Z & C24Z
Port Alma Wind Project
Erie Shores Wind Project
Load Flow Results:
Primary Demand: 28400MW
With Seven Bruce Units & 675MW of Wind-turbine Generation in Bruce Area
With no series compensation
With no Nanticoke Units in-service
MICHIGAN IMPORTS: 1499.4MW
NEW YORK IMPORTS at Niagara: 997.6MW
Losses on the Ontario System: 998.5MW
Load Flow Study - Reference Case:
Pre-Contingency
DIAGRAM IR-9A
20th February 2008

Filed: March 11, 2008
EB-2007-0050
Exhibit C
Tab 5
Schedule 9
Diagram B
Page 1 of 1

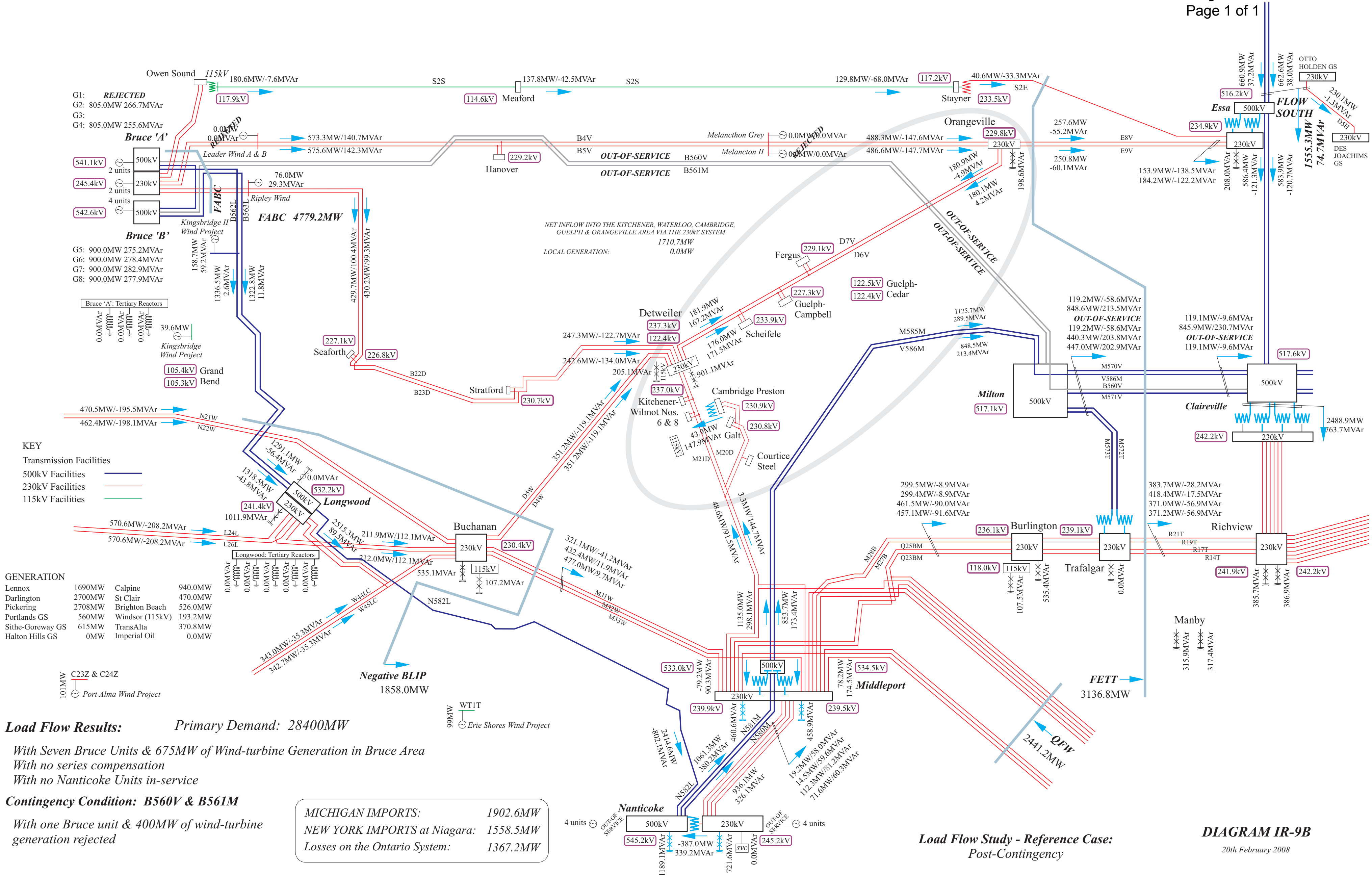


Exhibit No. 25

Saugeen Ojibway First Nations INTERROGATORY #18 List 1

Interrogatory

Ref. Exh. *B/T 6/S* 2 and other studies performed by the IESO
Issue Number: 1.1
1.1 Issue: Has the need for the proposed project been established?

Request

Please state what amount of the committed and potential installed wind generation planned for the vicinity of the Bruce Complex would be deemed firm (or dependable) generation for purposes of meeting Ontario's peak demand requirements assuming that the Bruce Milton 500 kV line were added.

Response

OPA has assumed that 20% of the installed capacity of any wind generation in Ontario will be available for meeting Ontario’s peak demand. This would be 140 MW of the 700 MW of existing and committed wind generation in the Bruce Area and 200 MW of the 1,000 MW of planned future wind generation in the Bruce Area.

Please refer to response Board Staff Interrogatory 1.6 for a discussion of the appropriate planning of the transmission system to accommodate the wind generation in the Bruce.

Exhibit No. 26

Energy Probe INTERROGATORY #3 List 1

Interrogatory

Issue Number: 1.1
Issue: Has the need for the proposed project been established?

Ref B/Tab 6/Sch 5/Appendix 5

Please provide historical capacity factors during the summer and winter peak periods for all generating units at Bruce A and Bruce B from their respective inservice dates to the present.

Response

As noted in Hydro One's earlier correspondence dated February 26, 2008 to the Board and parties, generation production data prior to market opening is not available. The historical capacity factors for Bruce A and Bruce B generating units from market opening to the present are as follows:

		Bruce Generation Units Seasonal Capacity Factors (%)					
Period	**Season**	**Bruce A Unit 3**	**Bruce A Unit 4**	**Bruce B Unit 5**	**Bruce B Unit 6**	**Bruce B Unit 7**	**Bruce B Unit 8**
2002	Summer			100	25	92	98
2002/2003	Winter			100	100	87	100
2003	Summer			91	88	97	98
2003/2004	Winter	22	85	92	99	100	57
2004	Summer	91	79	96	86	96	89
2004/2005	Winter	28	88	98	84	93	100
2005	Summer	84	96	98	96	38	99
2005/2006	Winter	58	98	93	83	94	88
2006	Summer	83	88	93	95	98	85
2006/2007	Winter	96	92	94	32	98	94
2007	Summer	91	77	91	86	98	93
2007/2008	Winter	89	88	88	92	53	85

Exhibit No. 27

Saugeen Ojibway First Nations INTERROGATORY #15 List 1

Interrogatory

Ref. Exh. *B/T 6/S* 2 and other studies performed by the IESO
Issue Number: 2.2

2.2 Issue: Has an appropriate evaluation methodology been applied to all the alternatives considered?

Request

Please state all the reasons underlying Hydro One's determination that it must develop 230 kV and 500 kV upgrades that will enable Hydro One to deliver the output of existing and planned wind generation in the vicinity of the Bruce Complex on a firm basis (i.e., so that deliveries of full rated wind capacity can continue after the outage of a double circuit 500 kV line).

a. Please provide all documents related to, arising from or used in connection with that determination, including, but not limited to, documents analyzing the cost/benefit ratio of upgrades necessary to provide firm transmission service to wind generators.
b. Please state the incremental cost of providing firm transmission service by means of 500 kV transmission upgrades (per kW and per kWh) for each planned block of wind generation.

Response

(a) & (b) Wind generation in the Bruce area is being provided as a result of government directives (please see Exhibit B, Tab 6, Schedule 5, Appendices 7 – 12). As a result, Hydro One, the OPA and the IESO have not analyzed the cost/benefit ratio of upgrades necessary to provide firm transmission service to wind generators nor determined the incremental cost of providing firm transmission service for each planned block of wind generation.

This application is not concerned with the need for the committed and planned generation resources forecast for the Bruce area, but rather whether the plan for the transmission facilities necessary to deliver all the committed and planned generation resources in the Bruce area is needed and is the best of the alternatives considered. In this case, there is only one alternative, the Bruce to Milton 500 kV line, that meets the need. Cost comparisons have been provided for the series compensation option (please refer to the responses to Pollution Probe Interrogatory 11 and to OEB Interrogatory 3.4). While the series compensation option does not meet the long-term capability need and has technical and operational disadvantages as compared to the Bruce to

Milton line, the cost comparison was done to establish that the proposed Bruce to Milton line is economically preferred even under such a comparison.

All generation in Ontario, including wind, is offered the same level of transmission service. To provide a less firm transmission service to wind generation in the Bruce would mean either their curtailment when the system is constrained or rejection of wind generators following critical contingencies. The former would result in congestion cost to the system similar to the cost of undelivered energy calculated in the response to Pollution Probe Interrogatory 9 and included in the economic assessment. The latter would be employing generation rejection for normal operation, which is not consistent with the applicable planning standards (please see the response to OEB Interrogatory 3.2).

Exhibit No. 28

21, rue d'Artois
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Session - 2000

22-301

APPLICATION OF REAL TIME THERMAL RATINGS FOR OPTIMIZING TRANSMISSION LINE INVESTMENT AND OPERATING DECISIONS

by

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ABSTRACT

The new deregulated economic environment in the utility market is forcing fundamental changes in the investment and operational decisions regarding transmission lines. Classical economic analysis of transmission lines was based on calculation of capital investment life of 40+ years and on long term plans of 5-10 years. This is no longer feasible.

Many transmission lines are limited by their thermal ratings. The conventional static or "book" ratings are based on conservative assumptions. The report describes how these ratings are shown to be 10-30% conservative over 90% of time.

Real time thermal ratings, as applied by the utilities in this report, provide an important method for postponing investment decisions until an economically optimal time. Other applications include avoidance of unnecessary remedial actions during contingencies and the use of data for economic dispatch. Real time ratings may also allow development of completely new market mechanisms to better utilize transmission networks.

KEY WORDS: Transmission lines, investment, real time ratings, upgrading, uprating.

1. INTRODUCTION

The new deregulated economic environment in the utility market is forcing fundamental changes in the investment and operational decisions regarding transmission lines. Decisions must now be made in a shorter timeframe, with increasing uncertainties and divorced from knowledge of generation planning.

In the past, it was not unusual to find that transmission line planning and investment decisions were made 5-10 years before the in-service date. While this was feasible as long as generation and power marketing were part of the same integrated system as transmission ownership, it is no longer the case today. Moreover, as the physical life of a transmission line is in excess of 50 years, most economic decisions were previously made assuming a similar economic life. For instance, because most utilities maintained large internal design and construction staffs, it was desirable to spread the manpower utilization over a long time period. to avoid constant hiring and layoffs.

A major present difficulty regarding transmission line decisions is the uncertainty of load flows, which depend on decisions made by power generating and marketing entities, which have different economic motivations than transmission owners. In many cases, the cost of line losses is insignificant compared to the short-term economic advantages of using different suppliers. Thus, paradoxically, lines designed for a physical life of 50+ years are now operated under an economic horizon of 1-3 years.

While overall international trends are uniformly directed towards more open economic competition and less regulation, the effects on any given transmission owner are increasingly diverse. While there is also a trend towards increasing the transfer limits of

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transmission lines, under different regulatory and economic environments a given technical situation can lead to totally different economic decisions regarding transmission. In the following, the authors describe such effects in four different utilities.

2. REAL TIME MONITORING

Over 50 utilities in nine countries are using tension-based transmission line monitoring systems either for evaluating the thermal limitations of transmission lines or for utilizing real time data for operational decisions. The basic application is described in [1]. Because essentially all lines are clearance-limited, knowledge of the line tension allows accurate determination of the line clearances compared to statutory requirements. When used together with line current information and some meteorological parameters, the data can be used to determine the thermally limiting line capability in real time. Further, statistical evaluation of the data allows predictions to be made of the line capabilities.

Most utilities start their application of tension monitoring by using the systems as data logging devices (as is the case of the four utilities in this report). For such applications, cellular communications are generally used, with periodic remote downloading of logged data allowing the accurate assessment of the actual thermal limitations of the lines. As shown by a number of case studies [2] and by the following examples, such data can effectively be used to validate rating assumptions and to optimize line upgrading plans. At a later stage, such monitors can be converted to radio-based real time communications, bringing about the full benefits of real time ratings [3].

The installed cost of tension monitoring systems varies, depending on line configuration, line length, and chosen communications methods, but is typically from \$1500 to \$3000 per circuit-km. In the following economic comparisons, the typical value of \$2000/km will be used unless otherwise specified.

The thermal capability of a transmission line depends on a complex combination of environmental parameters. Because lines must be operated safely under all conditions, their static (book) ratings are based on a set of conservative assumptions. Experience has shown that real time monitored lines can typically be operated at 10-30% higher ampacities than book ratings for 90-98% of time, because the actual condition of the line is known instead of conservatively estimated. The value of this incremental "free" capacity depends on the economic conditions of operation. The motives of real time monitoring users reflect such diverse considerations.

3. ECONOMICS OF REAL TIME RATING

In the prevalent low-growth environment of industrialized countries, a 10-15% increase in line capability, can account for 5-10 years of load growth. Typical conventional approaches to physically increasing line capabilities have usually been by either increasing structure heights by 1-2 m or by reconductoring the line with a slightly larger size conductor.

For a typical 230 kV line, the cost of a change of structure height amounts to \$5000-\$8000 per structure in materials and labor and results in a typical upgrading cost between \$4000 (10% of structures) and \$40000 (all structures) per kilometer. A complicating factor is that such upgrading can seldom be accomplished without extensive line outages, which are difficult to obtain for heavily loaded lines. Reconductoring costs are substantially higher, typically amounting to \$40000-\$60000/km. Thus, unless only a very small percentage of structures are clearance limiting, physical upgrading costs are a magnitude higher than real time monitoring.

Sometimes, very favorable economics can be achieved by optimally combining real time rating with limited physical uprating. For many lines, a 10-15% increase in ampacity can be achieved by modifying only a few spans. Similarly, a 10-15% capacity increase for the whole line can be achieved with a very high confidence factor by real time rating. Optimally, combining the two methods can increase the line capability by 20-35% at a very acceptable cost.

While real time thermal rating can increase line capabilities almost all of the time, there are situations in which the line capability will be limited to the level of the static rating or below. The economic attractiveness of real time ratings thus depends on the abilities to adjust the system load flows. A common economic incentive is the avoidance of the use of peaking generation. Generally though, the variable line capability cannot be fully exploited unless complementary financial mechanisms exist. Such financial mechanisms (e.g. energy swaps, interruptible contracts) are under development at many places.

The economic reasons for increasing line capabilities are often quite strong. It is typical to find that the cost difference between alternative generating facilities is at least \$10/MWh. For a typical 230 kV line, a 10% increase in line ratings results in an additional transfer capability of 40 MW. Thus, a \$70000 real time rating installation cost can be fully paid with less than 200 hours of incremental line capability use.

Many interfaces are limited only during contingencies. Real time capability monitoring allows operators to avoid a large number of cases of unnecessary remedial contingency actions. In many other cases, it allows operators to significantly limit the scope of remedial actions compared to those that would be determined by conservative book ratings.

The following four cases describe some of the reasons for real time monitoring in different environments.

4. ELTRA

ELTRA is the independent transmission system operator in Western Denmark, responsible for the 400 kV grid in the Jutland and Funen regions, the HVAC connections to Germany, and the HVDC connections to Sweden and Norway. Because of delays in the completion of the 400 kV grid, the system is still highly dependent on the regional 150 kV grid. Many of these lines are old and of limited capability, and in certain contingency conditions, they can cause significant generation cost increases.

ELTRA's nominal line ratings are based on a perpendicular wind of 0.6 m/s, an air temperature of 20°C, and a solar radiation of 900 W/m^2. The daily system dispatch uses a load table based on these assumptions. In contingency situations, an alternative load table allows use of ambient temperatures of 0, 10, or 30°C and a 1.5 m/s wind speed, provided that the actual observed wind speed is at least 6 m/s. Because the weather assumptions are based on the weather at the control center, significant uncertainty can exist on the applicability at any given line.

In 1997, ELTRA decided to install a tension-based monitoring system on the 85 km overhead section of the HVDC line to Norway. This line can be heavily loaded for several hours at a time. The tension monitor data was also compared to data from weather stations.

The accuracy of the tension data was verified by using optical sag measurements. It was found that the agreement was very close. The conductor temperature derived from the tension monitoring systems was also compared to direct measurements of conductor surface temperature. It was concluded that the direct temperature measurements were very uncertain because of the thermal resistance at the point of contact and the large differences between surface and core temperatures of the large conductor of the line.

We have, so far, concluded that:

- ELTRA's weather-based conductor temperature calculations agree within a few degrees with the data derived from the tension monitors.
- Because of the terrain difference along the line, there are large differences in local wind speeds. The winds at the southern part of the line are moderate, because of terrain cover. High winds are prevalent at the northern end, closer to the shoreline and in more open terrain.
- The solar radiation assumption of 900 W/m^2 is quite conservative. Net radiation sensor data from the tension monitors shows that 600 W/m^2 is exceeded only 3% of time.

The tension monitoring system has now been relocated to two 220 kV lines in the same region. The main objectives of the second phase of the program are to validate the AC loss calculations in the rating model and to do trials of real time dynamic rating of the lines.

5. NEW CENTURY ENERGIES

New Century Energies, Inc. (NCE) is the parent company of Public Service Company of Colorado (PSCo), headquartered in Denver, Colorado, and Southwestern Public Service Company (SPS), headquartered in Amarillo, Texas. PSCo has been studying real time ratings advantages since 1992. The studies included the installation of two line monitoring systems on the Broomfield – Valmont double circuit 230 kV line. These lines, which are only limiting in a first contingency case, have been operated using a summer normal rating of 135 MVA, based on a 0.61 m/s perpendicular wind speed assumption.

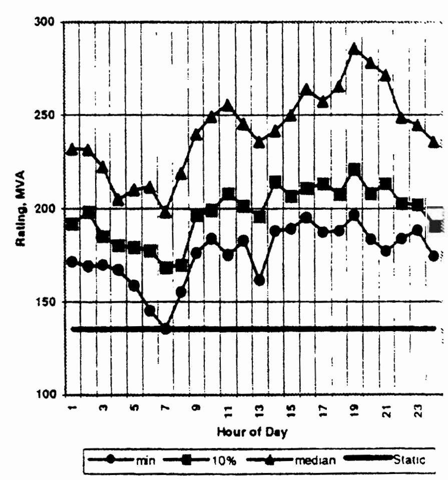


Figure 1 - Time of Day Ratings
Broomfield – Valmont Line

Analysis of the rating data from the most thermally limiting period of July 4-28, 1998 is shown in Figure 1. The data shows that for any time of day, the circuits have over a 90% probability of safely carrying at least 15% higher loads than the static rating and that for the most heavily loaded period (afternoons), the 90% probability limit is at least 30% higher than the assumed static rating.

In spite of the favorable rating information, it has been decided to reconductor the lines, because the load growth in the area has been much higher than anticipated. The tension monitors will be relocated to other highly loaded lines.

New Century Energies plans to construct a 345 kV tieline linking these two operating Companies by the end of 2001. Linking the operating companies will require an AC-DC-AC, or back-to-back, converter station because Colorado is in the Western Interconnection, which operates asynchronously from Texas in the Eastern Interconnection. The transfer capability between the companies will be limited to the 210 MW size of the converter station that will be built near Lamar, Colorado.

One of the limiting circuits for the full use of this capability is a 155 km 230 kV line between Boone and Lamar, of which PSCo owns 56%. The line uses a single 1272 kcmil conductor which could support power flows of 480 MW if the line had been designed and sagged differently. The actual design was for a 50°C conductor temperature with a clearance of 7.92 m. The NESC code for this line is actually 6.87 m, and when transmission line engineers studied the design, they concluded that the line could be rated for 325 MVA using standard PSCo line design assumptions for wind speed, solar and ambient conditions. However, because NCE wanted to accommodate power transfers of 210 MW over its 56 percent share of the line's capacity, it can be seen that the line needs to have a total capacity of 375 MW.

PSCo' transmission engineers conducted line studies to determine how to increase the capacity to 375 MW. Using a multi-span line analysis program, they determined that 79 structures would have to be raised, and that the cost would be in excess of $700,000. After considering this cost, it was decided that a better and a much less expensive solution would be to install tension-based monitoring systems on the line which would provide the system operators with the real time ratings. PSCo anticipates that the real time rating of the line will allow the full 210 MW operation of the converter facility a high percentage of time during the year. As the first step of this process, three monitoring stations will be installed on the line to provide base line thermal ratings data. At the time the converter station is completed, these systems will be converted to real time operation.

6. PORTLAND GENERAL ELECTRIC

Portland General Electric (PGE) began monitoring transmission lines using the tension-based method in 1994. Today, PGE is using the tension-based method to monitor five transmission lines. Plans are underway to install real time rating systems, which will send the rating data directly to the EMS system, on two of these lines before the year 2000. The real time rating systems will be installed prior to the project requirement dates in order for system operators to familiarize themselves with the new rating system. In addition, this will provide ample time to assess the effectiveness of the real time rating systems. The ultimate goal is to operate these two lines with real time ratings and defer two transmission projects totaling $2.9 million dollars. Power flow studies show that one project is required by the year 2003 and the other by 2005. These requirement dates were determined by using static line ratings assuming a fixed perpendicular wind speed of 0.89 m/s and a fixed ambient temperature of 0°C.

Each transmission line operates at 230 kV and interconnects two 230/115 kV bulk power substations. An outage of a parallel transmission line during peak system load could load either of the 230 kV lines to its static limit. With the real time rating systems, operational decisions will be based on the actual capacity of the transmission line, not the static limit. Operation at ampacities above static limits is possible if the real time rating (actual) is higher than the static limit, thus, avoiding corrective action. Should the real time rating system indicate that the transmission line is approaching its thermal limits, system operators would initiate a Remedial Action Scheme to reduce the line loading to the acceptable levels indicated by the real time monitors.

The number of years each project can be deferred depends upon area load growth and the effectiveness of the Remedial Action Scheme. Present Remedial Action Schemes can reduce transmission line loadings by approximately 8-10%. As such, each project can be deferred 5 to 7 years. Deferral of the 2003 project until 2010 and the 2005 project until 2012 equates to a capital savings of $1.2 million dollars. Evaluation of the deferral process will be reviewed annually.

7. TRANSPOWER (NEW ZEALAND)

Transpower is the owner and operator of the New Zealand high voltage grid and has installed a number of dynamic line rating units on circuits which form a first contingency constraint. The present static rating criteria assume 0.6 m/s perpendicular wind, no solar radiation, and a summer ambient temperature of 30°C. The results of over two years worth of measurements are consistent with those reported by New Century Energies, with on average a 90% probability of carrying 20% higher loads. The periods when dynamic line ratings closest approach the static thermal line ratings occur in the mornings and evenings when wind speeds are generally lowest. Capacities higher than the 20% average increase consistently occur in the mid morning to mid afternoon. This may appear to suggest that rerating lines during this period is feasible, but Transpower has experienced enough occasions when the line ratings have sharply dropped to the static limit that this temptation has been avoided.

The transmission lines involved in these studies form a significant constraint to the transmission of hydro power from the South Island to the population centers of the North Island. Relieving this constraint would significantly reduce the spot market price past the constraint. Despite what appear to be clear benefits, within the New Zealand spot market environment, Transpower has yet to find a means of recovering the cost of dynamic line rating equipment from those who would benefit from the lower spot market prices.

Market rules, as they are presently structured, also provide a block to the utilization of dynamic line rating. The New Zealand Electricity Market (NZEM) rules are founded on price certainty, and the dispatch process freezes generation offers and demand bids 2 hours before any trading period as part of the mechanisms that provide this certainty. Thus, when there is available dynamic line capacity, generation offers cannot be increased nor can generation be redispatched, which would result in a significant lowering of the spot market price past this constraint.

There have recently been a number of changes that may provide an impetus to solve these problems. As in other countries, New Zealand has had difficulty in building new transmission lines. Now, after a generation trip, transmission circuits can quickly overload when reserve is situated on the other side of a constraint. In an attempt to fix this problem within the market rules, it is proposed to apply precontingency constraints to lines that reduces their allowable transfer capacity. This would force the scheduling of reserves in the correct location to prevent postcontingency line overloads. However, this imposes a significant spot market cost on market participants that could well be removed by enabling dynamic line rating.

Problems with new transmission capacity investment in general have resulted in proposals to move to financial transmission rights. These financial instruments, when purchased by market participants, provide access to transmission capacity if there is a constraint. Options of this sort could be reworked to allow parties to capture the value of removing a constraint through the installation of dynamic line rating.

8. FUTURE ECONOMIC APPLICATIONS

8.1 Avoiding unnecessary contingency actions

Many system interfaces are limited because of contingency (post-fault) ratings, where it is assumed that the system can remain intact even if one or more major circuits are lost (N-1 or N-2 requirements). It is generally required that the system must be restored within a short period or that loads have to be reduced to maintain system security.

If the limitations are thermal, real time monitoring can often allow the operator to avoid or limit the extent of such remedial actions. A thermal contingency situation is real only if the limiting cooling conditions exist simultaneously at the same time the contingency happens, and even then only if the contingency lasts long enough for the conductor to reach a high enough temperature to cause a threat of clearance violation.

With real time monitoring, the operator can delay the corrective action until the critical clearances are reached, and can often limit the required correction to a substantially lesser amount than that indicated by book ratings. Furthermore, by logging the data from the real time monitoring system, the operator can later show that his remedial action was justified. This is becoming important in cased where the access for transmission rights is highly contested.

8.2 Predictive ratings

One of the major limitations for application of real time ratings has been that real time ratings can vary quite rapidly. Work is now being directed towards development of predictive methods which can be applied by system dispatch to determine probable ratings 1-24 hours in the future.

This method consists of providing the system dispatcher hourly capability predictions, which are based on a prior time period of 7-14 days. Examples of such rating predictions for a 230 kV line in Florida are shown in Figures 2-3. Note that afternoon ratings are higher than nightime ratings.

Note that the graphs show next day predictions based on the assumption that the following 24 hours is most likely similar than the prior 14 day period. The system dispatcher can use the predictions to select the risk level which best reflects the combination of economic consequences of remedial actions available for him in real time. Note that the use of a real time rating system allows the operator the possibility of using probabilistic economic dispatch, while maintaining the full safety and security because of available real time data.

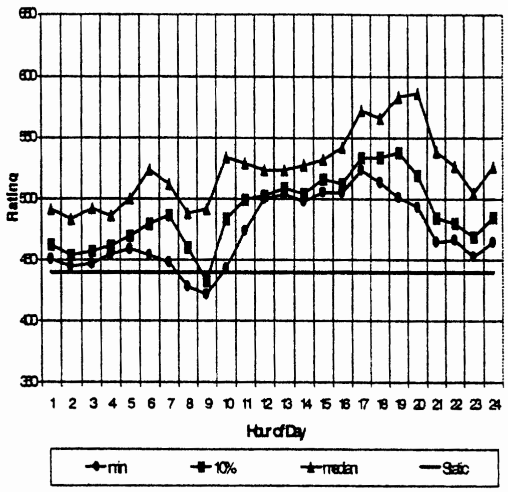


Figure 2 – Time of Day Ratings
Late June, Florida

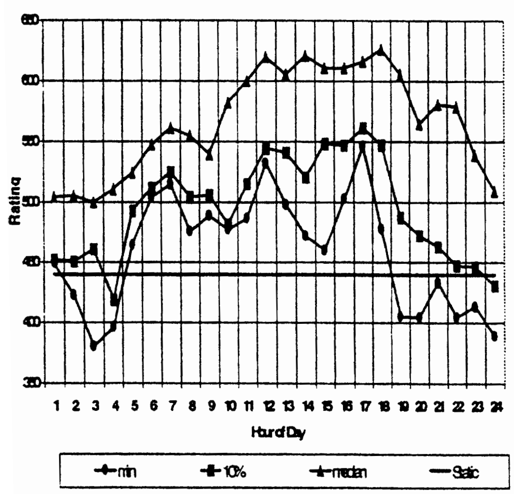


Figure 3 – Time of Day Ratings
Late January, Florida

9. CONCLUSIONS

1. Experiences of the utilities using tension monitors for real time line ratings indicate that in many cases, physical line upgradings can be postponed by careful evaluation of actual rating data. This can result in significant capital cost savings.

2. Several utilities are using or planning to use real time data provided by the monitors to the energy management system for making real time scheduling decisions.

3. Use of real time rating data for avoidance of unnecessary remedial actions during contingency situations is becoming economically attractive and practical in many networks.

4. Several utilities are planning to use data collected by real time monitoring systems for day-ahead scheduling decisions. This can allow use of ratings which are different for different times of day. It is relatively common to find that real time ratings are 10-30% higher during daytime than at night. In many systems, the higher daytime ratings coincide with the time of peak demand.

REFERENCES

[1] T.O. Seppa et al: "Use of On-Line Tension Monitoring for Real Time Thermal Ratings, Ice Loads and other Environmental Effects" CIGRE 22-102, Sept. 1998, Paris, France.

[2] D.A. Douglass & A-E. Edris: "Field Studies of Dynamic Thermal Rating Methods for Overhead Lines." IEEE T&D Conference Report, April 7, 1999 New Orleans, LA.

[3] T.O. Seppa: "Increasing Transmission Capabilities by Dynamic Line Rating." T&D World Expo Conference Proceedings, Nov. 12, 1997, Atlanta, GA.

Exhibit No. 29

Saugeen Ojibway First Nations INTERROGATORY #14 List 1

Interrogatory

Ref. Exh. *B/T 6/S* 2 and other studies performed by the IESO
Issue Number: **1.1**
1.1 Issue: Has the need for the proposed project been established?

Request

It appears that the interconnection studies for wind power consider the fact that when wind power is most likely to occur (i.e., under wind velocities beyond specified levels) that level of wind velocity will also allow higher thermal ratings of the transmission lines within a specified radius of the wind generation.
a. Please state whether the studies for determining needed transmission upgrades for the repowering of the Bruce units also consider such increased thermal ratings?
b. Has Hydro One conducted any studies of the correlation of wind velocities in the vicinity of committed and potential wind generation near the Bruce Complex with wind velocities along the Bruce-Milton corridor and the Bruce-Longwood-Nanticoke corridor? If so, please provide all documents related to, arising from or used in connection with such studies.
c. Please state whether Hydro One, IESO or OPA has considered use of dynamic ratings on the transmission facilities emanating from the Bruce Complex (ratings that vary with the ambient temperature, radiant energy *and/or* wind velocity along the transmission lines). If so, please provide all documents related to, arising from or used in connection with such consideration.

Response

(a) On Page 6 of the IESOs SIA Report (Ref: IESO_REP_0299, dated 11th April 2006 and filed as part of Hydro One's response to Pappas Interrogatory No. 1) for the Installation of series capacitors in the 500kV circuits between the Bruce Complex & Nanticoke GS, specific reference was made to the use of higher thermal ratings, corresponding to a wind speed of 15km/hr, for that section of circuits B4V & B5V within 50km of the Amaranth wind-turbine project.

Use of this higher rating corresponds to the IESOs Transmission Assessment Criterion which states:

Clause 6.2 Wind Power

For *connection assessments*, transmission line ratings will be calculated using 15km/hr winds, instead of the typical 4km/hr, within the vicinity of the wind farm and, with the approval of the transmission asset owner, out to a 50km radius.

In this SIA Report it was therefore shown that, after allowing for the higher rating corresponding to a 15km/hr wind speed on that section of circuits B4V & B5V between the connection of the Amaranth wind-turbine project and Orangeville TS, the circuits would be able to accommodate the projected transfers and rejection of these wind generators would not be necessary.

In the SIA Report for the new 500kV Bruce-to-Milton line, it was never necessary to assume a higher rating corresponding to a 15km/hr wind speed because, with the new 500kV line in-service, the projected flows on these circuits always remained within the ratings corresponding to the normal 4km/hr wind speed rating.

(b) Hydro One has not conducted any studies of the correlation between the wind velocities in the vicinity of committed and potential wind in the Bruce Area with the wind velocities along any transmission corridor.

(c) For the actual day-to-day operation of the transmission system, the IESO receives "dynamic" ratings from Hydro One at 5 minute intervals that recognize both the local ambient temperatures and the prevailing wind speeds, while also allowing for the solar conditions and the actual pre-contingency loadings on the circuits. With this latest information, the IESO is then able to maximize the use of the available transfer capability.

Exhibit No. 30

Pollution Probe INTERROGATORY #47 List 5

Interrogatory

Ref. Response to Pollution Probe Interrogatory No. 7 List 1 (Exh. C / T 2 / S 7)

Issue Number 2.0

2.0 Issue: Project Alternatives

Request

a) Please provide all workpapers associated with the computation of lockedin energy quantities listed in the "undelivered energy (MWh)" table for parts a) through e) of the response. Provide these workpapers in Excel or equivalent spreadsheet format with formulas intact.
b) Please describe in complete detail the analysis conducted to obtain the estimate of locked-in energy provided in the "undelivered energy (MWh)" table as a response to parts a) through e) of the interrogatory. Please include descriptions of the temporal detail for each component of the response (e.g. for wind, nuclear, and transmission components).
c) Please provide the estimates of locked-in energy for the finest level of temporal detail calculated.
d) Please provide the "probabilistic distributions" for both wind and nuclear generation that was developed as part of the response.
e) Please provide the "probabilistic distribution of total generation in the Bruce area" that was developed as part of the response.
f) Please provide the "transfer-capability probability distributions" that were developed as part of the response.
g) Please describe the specific assumptions made concerning the overall state of the Ontario transmission system for the periods in which Bruce area transfer-capability probability distributions were developed.

Response

a) Hydro One and OPA have declined to answer this Interrogatory due to its confidential and commercial sensitivity. Please refer to correspondence on behalf of Hydro One dated March 13, 2008.

b) The analysis used to respond to Pollution Probe Interrogatory 7 is based on the fact that the output of wind generation and nuclear generation, and the capability of the Bruce transmission system are not constant. The OPA's Financial Evaluation Model ("Model") uses probabilistic distributions developed from historical data for wind and transmission capability information, and from estimates of nuclear unit availability from a probabilistic derivation. The Model considers eight different time periods within a year (to match the time periods used in the energy cost tables and as described in response to Pollution Probe Interrogatory 24) and three different refurbishment states (these refurbishment states are user-selected in operating the Model) in its calculations. In order to simplify the calculations, the Model uses a representative sample from each distribution.

With regard to each distribution, the variability of wind generation output is modeled using the simulated hourly data from the AWS True Wind Report. The wind generation output distributions for each time period are created by allocating the AWS data to each of the eight time periods.

The nuclear generation distribution modeling is based on the number of units in operation (i.e. eight units less the number removed for refurbishment, as selected by the user), the units' Effective Forced Outage Rate (EFOR) and the units' planned outage assumptions. A two-state model is used in conjunction with these assumptions.

Transmission capability is determined based on normal system conditions established by the IESO, less a reduction (referred to as a penalty) to reflect other real-time system limitations on the Bruce Area transmission system. The Model uses a penalty distribution based on Bruce Area transmission system historical performance data between 2005 and 2007.

Total generation distributions cannot be created by adding the wind generation and nuclear generation distributions together. It is assumed that the wind and nuclear generation are independent events. Therefore, the Model conducts a convolution of the wind generation and nuclear generation distributions to determine the total generation distribution for the Bruce Area. (A convolution of a discrete number of samples is conducted by taking every possible combination of two points, one from each distribution. The number of samples is chosen by the model user.)

Undelivered energy distributions are determined by conducting a convolution of the transmission capability and total generation distributions. The expected values of these distributions are scaled to represent the number of hours in the corresponding time period. The only temporal parts of the Model's analysis are created when these expected values are assigned to the user-selected monthly refurbishment profile. These monthly values are then totaled to provide annual results.

c) A supplementary response is filed as Attachments A, B and C. This material is being filed in response to the Board's April 7 Order in respect of Generation Forecast Information. It includes two redacted tables (Attachment B and Attachment C). The OPA plans to make a separate filing in respect of these tables under the Board's Practice Direction on Confidential Filings.

d) The Model used to determine the amount of undelivered energy considers probabilistic distributions for wind and nuclear generation for each year of study. The wind generation is modeled for each of the eight time periods discussed in the above-referenced response. The nuclear generation is modeled for two time periods (winter/summer and shoulder) and three different states at Bruce NGS (zero, one and two units removed for refurbishment). There are 266 probabilistic distributions representing nuclear and wind generation for the entire study period between 2012 and 2030. All of the distributions are similar; therefore only one wind generation probabilistic distribution and one nuclear generation probabilistic distribution are shown in Figures 1 and 2 below. The Model cannot process the entire distribution and needs to sample it in order to conduct its calculations. The sampled distribution is shown by the red line that moves stepwise. The Model uses an average sampling method and does not take into account the peak values (making any calculations conservative ones, such as those in the response to the referenced interrogatory).

<u>Figure 1</u>

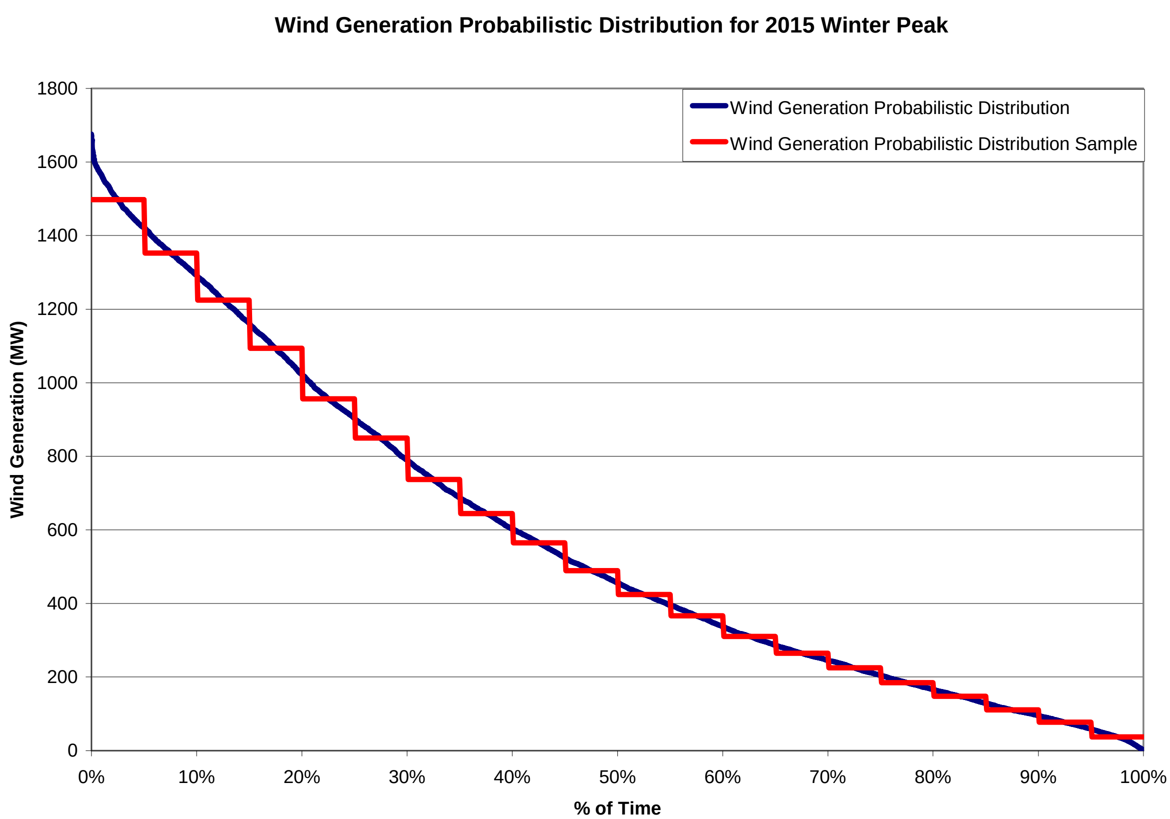
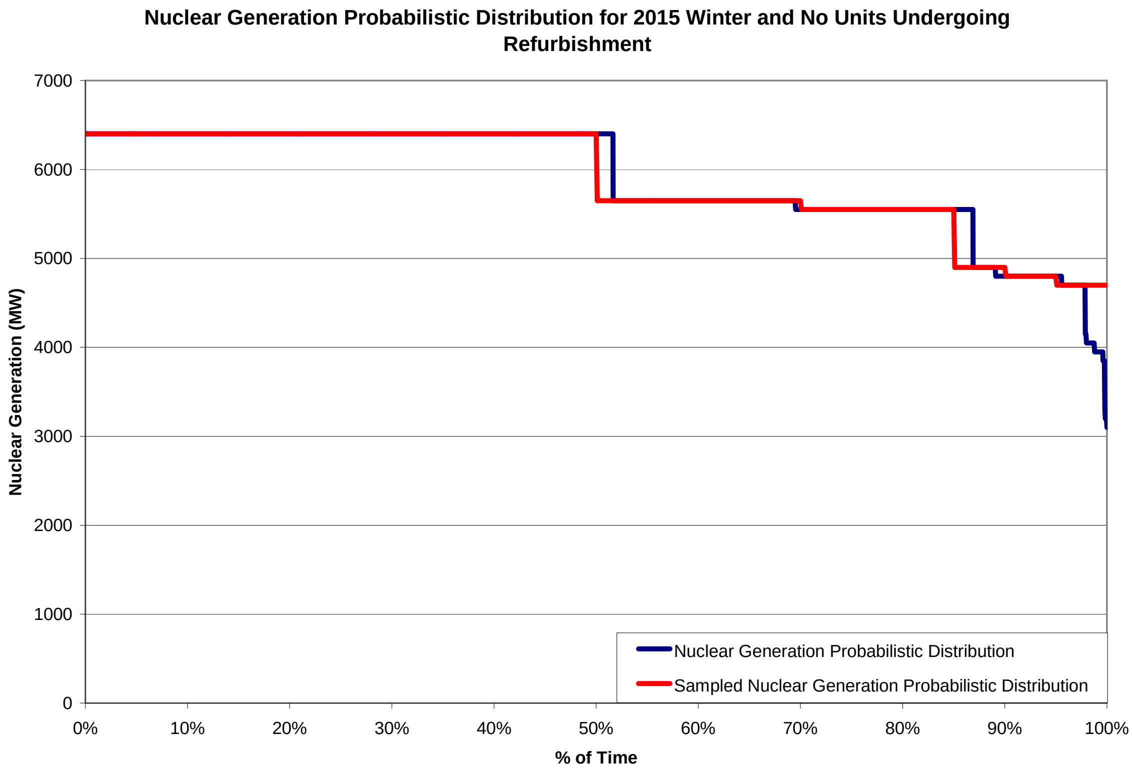
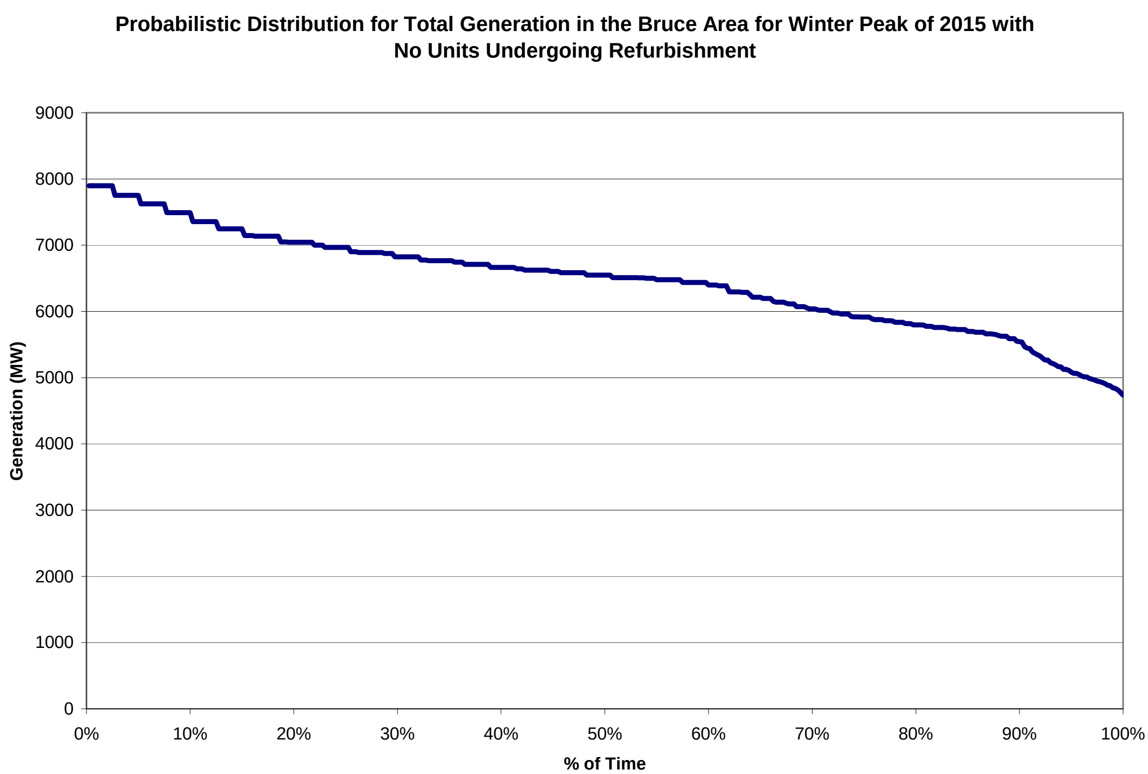


Figure 2



e) There are 24 total generation cases modeled for each year of study. This totals 456 distributions for the study period. Again, because all of the distributions are similar, only one example of this distribution is shown in Figure 3 below.

Figure 3



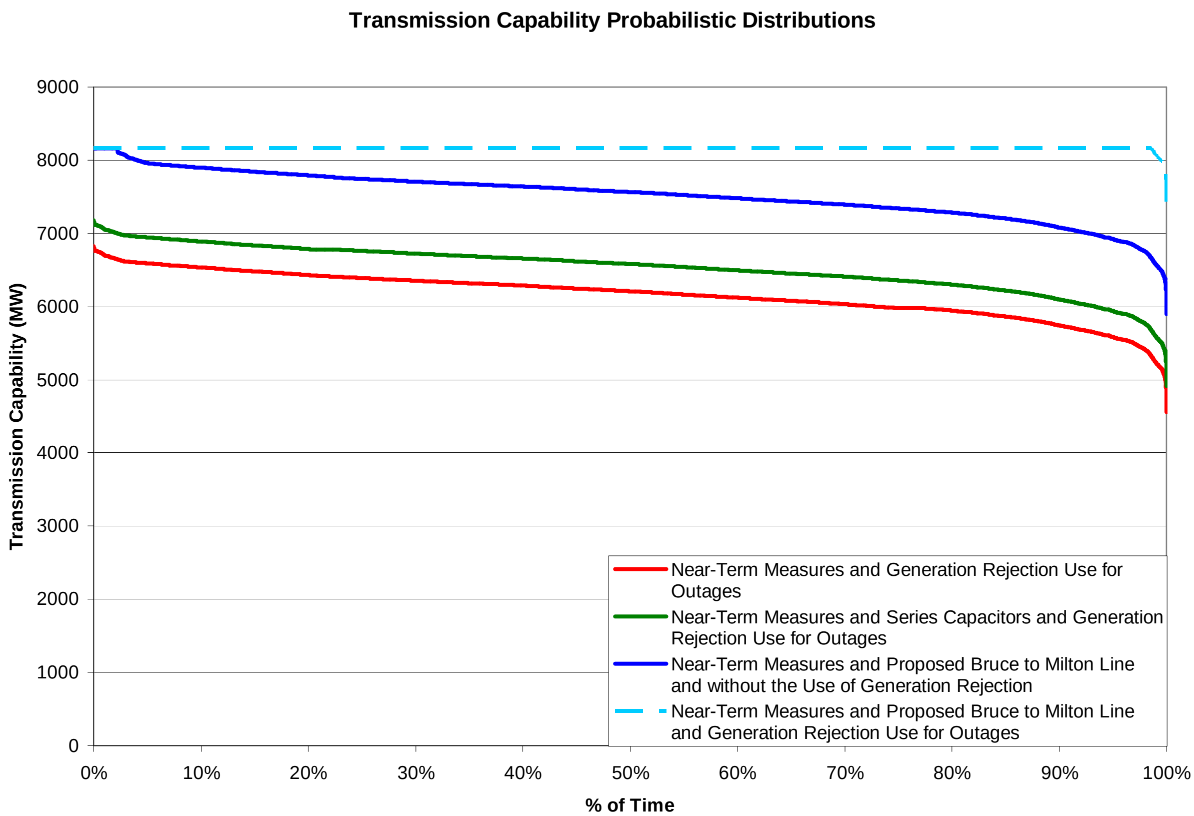
f) As explained in the response to part b) of this Interrogatory, transmission capability is modeled using normal system limits calculated by the IESO and historical transmission system penalty information. The Model takes into account historical de-rating patterns and uses these results in the consideration of future transmission capability. The resulting reduction in the transmission capability (i.e. the penalty) to the Bruce Area transmission system would be the same for each transmission system configuration (e.g., series capacitors, new Bruce to Milton line, etc.). The Model also assumes that the penalty would be the same for the study duration. Both of these assumptions are conservative as it is likely that a transmission system employing the new Bruce to Milton line would be more robust and would have a lower penalty due to transmission system outages, as compared to one employing series capacitors. This is because stress caused to the existing system using series capacitors would expected to be much higher and a larger transmission penalty (i.e. consequences) would likely result for any particular outage.

Also, it is expected that as the transmission system ages, outages would become more frequent and cause a larger penalty sustained for a longer period of time in the future.

Figure 4 shows transmission capability for each of the systems that the OPA modeled. Note that the capability of the proposed Bruce to Milton line drops below the 8,100

MW level in the distribution. This is due to the fact that generation rejection was not modeled for this option under outage conditions, while it was modeled for the other two cases. If generation rejection were to be assumed for the Bruce to Milton option under outage conditions (which will be the normal operating mode), the capability of the Bruce to Milton option would be able to be maintained at the 8,100 MW level throughout the period as illustrated in Figure 4 by the dashed line on the graph. This comports with the identified level of required or needed transfer capability fro the Bruce Area.

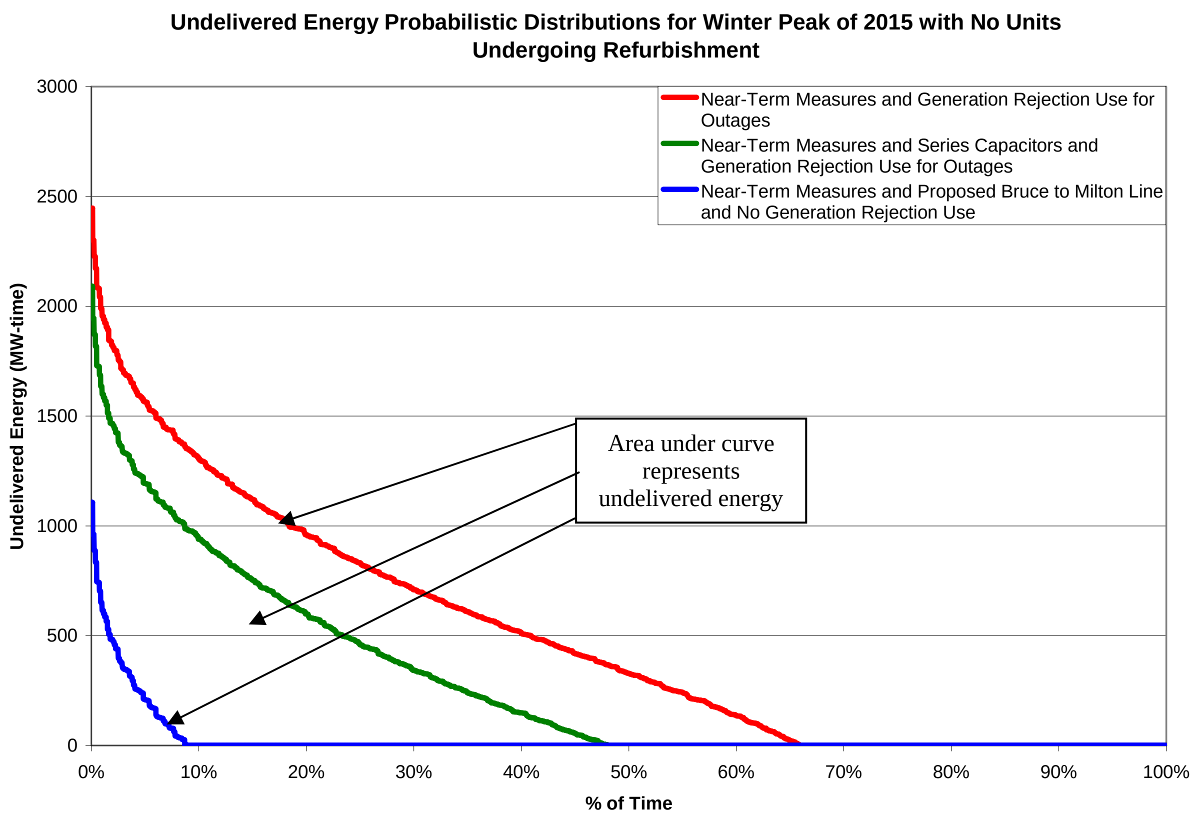
Figure 4



The transmission capability distributions shown in Figure 4 are then sampled in the same way as those for nuclear and wind generation. The transmission capability and total generation distributions are then convolved to derive the undelivered energy distribution. There are 456 undelivered energy distributions for each transmission system modeled. An example of the undelivered energy distribution for the winter peak in 2015 with no units undergoing refurbishment for both the proposed Bruce to Milton line (without any GR use) and for the series capacitor option (with GR use under outage conditions) is shown in Figure 5 below.

The undelivered energy is determined by using the expected value (mean) of these distributions to calculate undelivered energy for a certain period of time. Figure 5 below shows the undelivered energy calculated for the 2015 winter peak period. The winter peak period is one of the eight time periods used for the annual calculation. The area under each of the curves is a component of the amount of the 2015 undelivered energy in the table of undelivered energy values provided in the response to Pollution Probe Interrogatory 7.

Figure 5



The results of the OPA's analysis show that the Bruce transmission system reinforced with the Bruce to Milton line will have minor amount of undelivered energy incurred during equipment outage conditions. That small amount would be eliminated through the infrequent use of GR under those conditions. On the other hand, Figure 5 also depicts that the Bruce transmission system when reinforced only with series capacitors (and assuming the use of GR only under outage conditions) is expected to result in a significant amount of undelivered energy. For 2015 this amount is expected to be 1.3 TWH and is approximately 20% of the energy output of a Bruce A unit operating 100% of the time at 750 MW. Using the OEB-approved CDM avoided cost forecast as a proxy for the price of the replacement energy in 2015, the amount would be $63 million expressed in 2007 dollars. Please refer to Pollution Probe

Interrogatory 9. Over the entire study period, the net present value of the undelivered energy for the series capacitors option is $540 million expressed in 2007 dollars. This amount does not take into account transmission losses.
Figure 5 also shows the undelivered energy associated with reinforcing the Bruce transmission system with only the near-term measures. For 2015, undelivered energy is 2.6 TWH or 40% of the energy output of a Bruce A unit operating 100% of the time at 750 MW. Using the OEB-approved CDM avoided cost forecast as a proxy for the price of the replacement energy in 2015, the amount would be $120 million expressed in 2007 dollars. Please refer to Pollution Probe Interrogatory 9. Over the entire study period, the net present value of the undelivered energy for the near term measures option is approximately $1.1 billion expressed in 2007 dollars. This amount does not take into account transmission losses.

While the amount and cost of undelivered energy are important considerations, the frequency of exposure to congestion on the Bruce transmission system is also a critical measure of the impact of system constraints. As shown in Figure 5, the system is expected to be congested for a large percentage of time (e.g. approximately 50 % of the time for series compensation and close to 70% of the time for the near-term only measures option). Operation of the system with congestion would create complexities and create operational inefficiencies. For example, the Bruce nuclear units would have to operate with constrained output, there would be need for more frequent arming of the wind and nuclear units for rejection, and, when the limit of the ability to maneuver the output of the Bruce units is reached, there would be need to curtail the output of wind generation.

g) Please refer to the response to part f) above.

OPA's Bruce to Milton Financial Evaluation Model Assumptions

1.0 Purpose

The methodology of the OPA's Financial Evaluation Model ("Model") was described in detail in the response to Pollution Probe Interrogatory 47. This document describes the assumptions the Model uses to determine the undelivered energy and other results presented in the responses to various Interrogatories. These assumptions can be varied using the Model provided in the response to Pollution Probe Interrogatory 9.

2.0 Assumptions

All of the OPA's assumptions, with the exception of the Bruce unit refurbishment schedules, were included with the Model attached as part of the response to Pollution Probe Interrogatory 9. The monthly "in-service" schedule that the Model utilizes to determine the number of units out of service for refurbishment has been included as Attachment C to the updated response to Pollution Probe Interrogatory 47 (Exhibit C Tab 2 Schedule 47 Attachment C).

2.1 Wind Generation Assumptions

The Model uses wind data supplied to the OPA by AWS TrueWind, LLC. The Model incorporates the AWS data for Group No. 6 and the proportion of Group No. 0 that is in the Bruce Area. These Groups are defined in the AWS TrueWind Report, which is available on the OPA website. This data is sorted into each of the 8 time periods defined in the response to Pollution Probe Interrogatory 24. These time period definitions have been reproduced below as Tables 1 and 2. This data is used by the Model to determine the probabilistic distribution of wind generation described in the response to Pollution Probe Interrogatory 47 (d).

Table 1 – Definition of Seasons used by the Model

Season	Months Included
Winter	December – March
Summer	June – September
Shoulder	April, May, October, November

Table 2 – Definition of Time Periods used by the Model

	Winter	Summer	Shoulder
Peak	07:00-11:00 and 17:00 – 20:00 Weekdays	11:00-17:00 Weekdays	None
Mid-Peak	11:00-17:00 and	07:00-11:00 and	07:00-22:00 weekdays

	2000-2200 Weekdays	17:00-22:00 Weekdays	
Off-Peak	00:00-07:00 and 22:00-24:00 Weekdays; All hours weekends	00:00-07:00 and 22:00-24:00 Weekdays; All hours weekends	00:00-07:00 and 22:00-24:00 Weekdays; All hours weekends

The 700 MW of committed wind is assumed to be in-service by 2009. The 1,000 MW of future planned wind is assumed to begin coming in-service in 2013 and the full 1,000 MW of future planned wind is assumed to be in-service in 2015.

2.2 Nuclear Generation Assumptions

The Model utilizes performance information based on the average 2005-2006 availability of the Bruce B units. The average 2005-2006 availability of the Bruce B units was 86.1%. Each unit was assumed to undergo 45 days of planned outage every two years for maintenance. The Model assumes that all planned outage takes place during the Shoulder period (refer to Table 1). An effective forced outage rate (EFOR) of 8% was assumed in order to obtain an availability of 86.6%.

The Bruce A units were assumed to leave service for refurbishment and return to service after refurbishment as planned in the Bruce contract. Each Bruce B unit is assumed to require 2.5 years to refurbish. The first Bruce B unit is assumed to leave service for refurbishment in 2018. The second Bruce B unit is assumed to leave service for refurbishment in 2019. The third Bruce B unit is assumed to leave service for refurbishment at the same time that the first Bruce B unit returns to service after refurbishment. The fourth Bruce B unit is assumed to leave service for refurbishment at the same time that the second Bruce B unit returns to service after refurbishment.

The Model assumes that each of the Bruce A units have a net generation capacity of 750 MW. The Model assumes that each of the Bruce B units have an average net generation capacity of 820.95 MW in 2009, and increases linearly to a net generation capacity of 850 MW in 2013.

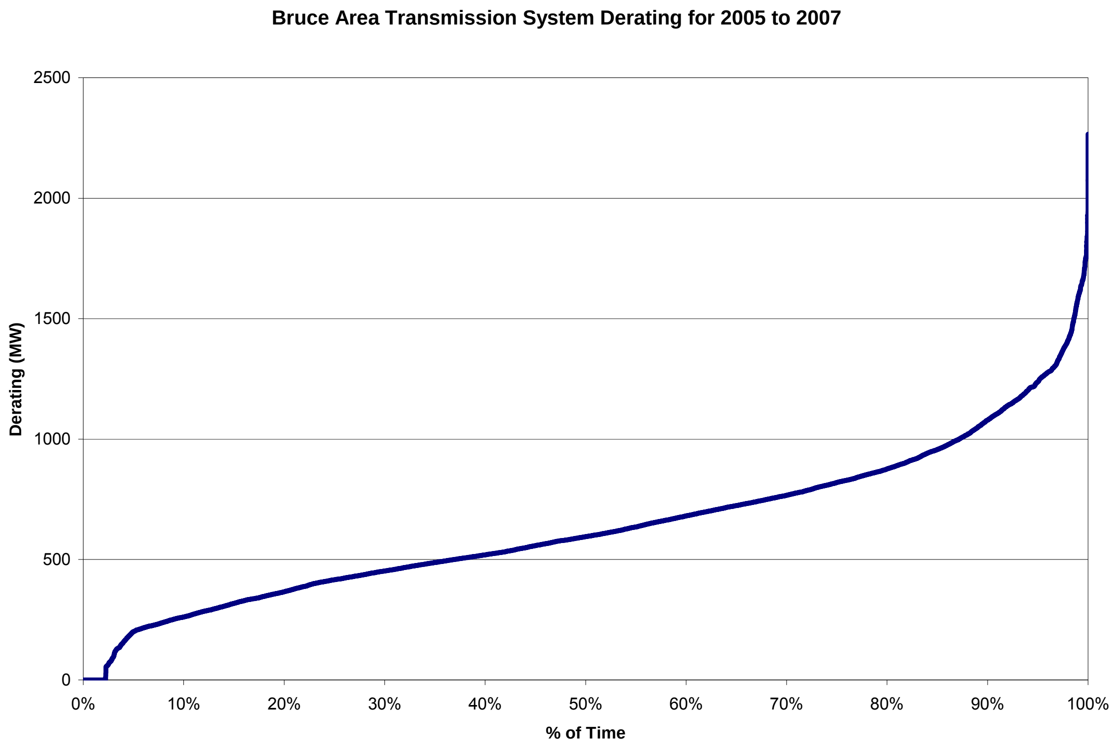
2.3 Transmission System Capability Assumptions

The Model uses normal system transmission limits calculated by the IESO for each of the transmission configurations to be studied (e.g. the implementation of Near-Term Measures and the new Bruce to Milton Line) based on a 500 MW flow from London eastward ("NBLIP=500MW"). These normal system transmission limits are shown in Table 3 below. The Model takes into account historical derating patterns when assessing the Bruce Area transmission capability (please refer to the response to Pollution Probe Interrogatory 47 (f) for details regarding the methodology of the Model). The Model utilizes historical transmission system derating data for the Bruce Area transmission system for 2005 to 2007. This data is shown in the duration curve in Figure 1 below.

Table 3 – Normal System Transmission Limits @ NBLIP = 500 MW

Normal System Transmission Limits (MW)	Near-Term Measures	Near-Term Measures + GR (Short-Term Use)	Near-Term Measures + SCAP	New BxM Line
Elements Out-of-Service (use GR)	6821	6821	7176	8160
All Elements In-Service	5976	6821	6776	8160

Figure 1 – Bruce Area Transmission System Derating Data



2.4 Discount Rate Assumptions

The Model utilizes a real discount rate of 4%.

2.5 Capital Costs Assumptions

The Model uses capital costs that exclude escalation and interest. These were provided by Hydro One and are shown below in Table 4.

Table 4 – Capital Costs (M$)

Year	NTM	NTM + GR	NTM + GR + SCAP	NTM + GR + BxM Line
2009	66	66	98	322
2010	150	157	209	341
2011	0	0	0	115

NTM ≡ Near-Term Measures
GR ≡ Generation Rejection (Expansion of the Bruce Special Proection System)
SCAP ≡ Series Capacitors
BxM ≡ Bruce to Milton

2.6 Energy Costs Assumptions

The Model uses the avoided energy costs from Table 11 of Navigant's "Avoided Cost Analysis for the Evaluation of CDM Measures". For the years 2025 to 2030 it is assumed that real energy prices are constant. The energy costs are shown below in Table 5.

Table 5 – Avoided Energy Costs (2005$/MWh)

Year	WinPeak	WinMid	WinOff	SumPeak	SumMid	SumOff	ShoMid	ShoOff
2009	91.4	64.7	41.7	86.6	67.9	40.8	68.1	37.5
2010	90.4	63.3	43.5	86.5	67.1	40.3	64.7	36.6
2011	85.6	61.8	42.8	81.3	66.1	39.6	63.7	35.4
2012	85.2	61.5	42.3	87.0	67.1	40.8	65.3	38.3
2013	92.6	65.7	46.4	87.7	70.6	42.0	66.6	40.7
2014	90.7	68.6	47.4	93.7	73.1	43.0	69.4	41.6
2015	89.7	68.5	51.3	108.3	78.6	46.2	70.4	44.7
2016	90.4	68.7	50.9	106.3	77.7	46.1	69.8	44.6
2017	91.1	68.9	50.6	104.3	76.8	46.0	69.3	44.6
2018	91.7	69.0	50.2	102.4	75.8	45.9	68.7	44.5
2019	92.2	69.1	49.8	100.5	74.9	45.7	68.1	44.4
2020	92.6	69.1	49.4	98.7	74.0	45.5	67.5	44.3
2021	92.5	68.9	49.5	96.7	74.0	45.6	67.7	44.4
2022	92.3	68.6	49.6	94.9	74.0	45.7	67.9	44.5
2023	92.0	68.3	49.6	93.0	74.0	45.7	68.1	44.6
2024	91.7	68.0	49.7	91.2	73.9	45.7	68.2	44.6
2025	91.3	67.6	49.6	89.4	73.7	45.7	68.2	44.7
2026	91.3	67.6	49.6	89.4	73.7	45.7	68.2	44.7
2027	91.3	67.6	49.6	89.4	73.7	45.7	68.2	44.7
2028	91.3	67.6	49.6	89.4	73.7	45.7	68.2	44.7
2029	91.3	67.6	49.6	89.4	73.7	45.7	68.2	44.7
2030	91.3	67.6	49.6	89.4	73.7	45.7	68.2	44.7

2.7 Peaker Costs Assumptions

The Model uses the capacity cost of a Simple-Cycle Gas Turbine ("SCGT") to determine the cost of capacity lost at the time of system peak. This was determined to be approximately 66.9 $/kW-year. The information used to determine the cost of 66.9 $/kW-year is presented below in Table 6.

Table 6 – SCGT Information

Capital Cost (2007 C$/kW)	$665
Fixed Operating Cost (2007 C$/kW-year)	$16
Project Life (years)	20
Average Annual Availability (%)	97%
Real Discount Rate (%)	4%

2.8 Losses Assumptions

The model assesses two different types of losses: (1) energy losses, and (2) capacity losses at system peak. Energy losses are calculated for a system load of 22,000 MW. The cost of energy losses are assessed using the avoided energy costs described in section 2.6 above. Capacity losses at system peak are calculated for a system load of 28,400 MW. The cost of capacity lost at system peak is determined using the peaker cost described in section 2.7 above.

The two losses described above are determined for different configurations of the Bruce Area transmission system (e.g. the implementation of Near-Term Measures and the new Bruce to Milton Line) at 17 different Bruce Area generation levels. PSS/E was used to determine the system losses at different levels of Bruce Area generation for different transmission system configurations. The PSS/E results used for the energy losses (system load of 22,000) are shown in Table 7 below. The PSS/E results used for the capacity losses at system peak (system load of 28,400) are shown in Table 8 below.

Table 7 – System Losses at a System Load of 22,000 MW

	System Losses (MW)			
Bruce Area Generation (MW)	NTM	NTM + GR	NTM + GR + SCAP	NTM + GR + New BxM Line
3500	519	519	519	504
3750	522	522	522	505
4000	526	526	527	507
4250	532	532	533	509
4500	539	539	540	513
4750	547	547	549	518
5000	557	557	559	523
5250	569	569	570	530
5500	581	581	583	537
5750	596	596	597	546
6000	612	612	612	555
6250	629	629	629	566
6500	647	647	647	577
6750	668	668	666	589
7000	689	689	687	603
7250	712	712	709	617
7500	737	737	732	632

NTM ≡ Near-Term Measures
GR ≡ Generation Rejection (Expansion of the Bruce Special Proection System)
SCAP ≡ Series Capacitors
BxM ≡ Bruce to Milton

Table 8 – System Losses at a System Load of 28,400 MW

	System Losses (MW)			
Real Flow Buckets (MW)	NTM	NTM + GR	NTM + GR + SCAP	NTM + New BxM Line
3500	997	997	998	983
3750	999	999	1000	982
4000	1003	1003	1003	983
4250	1008	1008	1008	984
4500	1015	1015	1014	986
4750	1022	1022	1022	990
5000	1031	1031	1031	994
5250	1042	1042	1042	999
5500	1054	1054	1053	1006
5750	1067	1067	1067	1013
6000	1081	1081	1081	1021
6250	1097	1097	1098	1031
6500	1114	1114	1115	1041
6750	1132	1132	1134	1052
7000	1152	1152	1154	1065
7250	1173	1173	1176	1078
7500	1195	1195	1199	1093

NTM ≡ Near-Term Measures
GR ≡ Generation Rejection (Expansion of the Bruce Special Proection System)
SCAP ≡ Series Capacitors
BxM ≡ Bruce to Milton

The Model analyzes 8 different time periods and 3 different refurbishment states as described in the response to Pollution Probe Interrogatory 47 (d). Flows away from the Bruce area are assessed for all of these different states. The flows are constrained by each transmission system configuration's capability.

2.8.1 Energy Losses Methodology

The Model assigns the modelled flows into each of the 17 generation levels. System losses are determined by taking the average of these loss distributions in the same way that undelivered energy is determined (see the response to Pollution Probe Interrogatory 47 (f)). The cost of energy losses is then assessed relative to the transmission system configuration employing the new Bruce to Milton line.

2.8.2 Capacity Losses at System Peak Methodology

The Model analyzes the modelled flows for the Summer period (Summer Peak, Summer Mid-Peak, Summer Off-Peak periods described in Table 2 above) and determines the maximum flow during the Summer period for each state analyzed. The capacity losses at system peak are determined by assessing the system losses for the maximum Summer period flow. The cost of the capacity losses at system peak are determined relative to the transmission system configuration employing the new Bruce to Milton line.

Filed: April 10, 2008
EB-2007-0050
Exhibit C
Tab 2
Schedule 47

Attachment B

Undelivered Energy (MWh)

Date	Part a)	Part b)	Part c)	Part d)	Part e)
Jan-12	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Feb-12	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Mar-12	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Apr-12	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
May-12	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Jun-12	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Jul-12	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Aug-12	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Sep-12	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Oct-12	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Nov-12	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Dec-12	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Jan-13	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Feb-13	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Mar-13	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Apr-13	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
May-13	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Jun-13	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Jul-13	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Aug-13	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Sep-13	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Oct-13	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Nov-13	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Dec-13	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Jan-14	314426	314426	169899	169899	77929
Feb-14	314426	314426	169899	169899	77929
Mar-14	314426	314426	169899	169899	77929
Apr-14	36687	36687	12140	12140	4305
May-14	36687	36687	12140	12140	4305
Jun-14	216665	216665	96803	96803	41597
Jul-14	216665	216665	96803	96803	41597
Aug-14	216665	216665	96803	96803	41597
Sep-14	216665	216665	96803	96803	41597
Oct-14	36687	36687	12140	12140	4305
Nov-14	36687	36687	12140	12140	4305
Dec-14	314426	314426	169899	169899	77929
Jan-15	355256	355256	203198	203198	96848
Feb-15	355256	355256	203198	203198	96848
Mar-15	355256	355256	203198	203198	96848
Apr-15	49810	49810	19127	19127	7081

May-15	49810	49810	19127	19127	7081
Jun-15	238269	238269	112758	112758	49615
Jul-15	238269	238269	112758	112758	49615
Aug-15	238269	238269	112758	112758	49615
Sep-15	238269	238269	112758	112758	49615
Oct-15	49810	49810	19127	19127	7081
Nov-15	49810	49810	19127	19127	7081
Dec-15	355256	355256	203198	203198	96848
Jan-16	355256	355256	203198	203198	96848
Feb-16	355256	355256	203198	203198	96848
Mar-16	355256	355256	203198	203198	96848
Apr-16	49810	49810	19127	19127	7081
May-16	49810	49810	19127	19127	7081
Jun-16	238269	238269	112758	112758	49615
Jul-16	238269	238269	112758	112758	49615
Aug-16	238269	238269	112758	112758	49615
Sep-16	238269	238269	112758	112758	49615
Oct-16	49810	49810	19127	19127	7081
Nov-16	49810	49810	19127	19127	7081
Dec-16	355256	355256	203198	203198	96848
Jan-17	355256	355256	203198	203198	96848
Feb-17	355256	355256	203198	203198	96848
Mar-17	355256	355256	203198	203198	96848
Apr-17	49810	49810	19127	19127	7081
May-17	49810	49810	19127	19127	7081
Jun-17	238269	238269	112758	112758	49615
Jul-17	238269	238269	112758	112758	49615
Aug-17	238269	238269	112758	112758	49615
Sep-17	238269	238269	112758	112758	49615
Oct-17	49810	49810	19127	19127	7081
Nov-17	49810	49810	19127	19127	7081
Dec-17	355256	355256	203198	203198	96848
Jan-18	85491	85491	33733	203198	96848
Feb-18	85491	85491	33733	203198	96848
Mar-18	85491	85491	33733	203198	96848
Apr-18	4762	4762	883	19127	7081
May-18	4762	4762	883	19127	7081
Jun-18	33400	33400	9258	112758	49615
Jul-18	33400	33400	9258	112758	49615
Aug-18	33400	33400	9258	112758	49615
Sep-18	33400	33400	9258	112758	49615
Oct-18	4762	4762	883	19127	7081
Nov-18	4762	4762	883	19127	7081
Dec-18	85491	85491	33733	203198	96848
Jan-19	6338	6338	1073	203198	96848
Feb-19	6338	6338	1073	203198	96848
Mar-19	6338	6338	1073	203198	96848
Apr-19	0	0	0	19127	7081

May-19	0	0	0	19127	7081
Jun-19	1037	1037	96	112758	49615
Jul-19	1037	1037	96	112758	49615
Aug-19	1037	1037	96	112758	49615
Sep-19	1037	1037	96	112758	49615
Oct-19	0	0	0	19127	7081
Nov-19	0	0	0	19127	7081
Dec-19	6338	6338	1073	203198	96848
Jan-20	6338	6338	1073	33733	15907
Feb-20	6338	6338	1073	33733	15907
Mar-20	6338	6338	1073	33733	15907
Apr-20	0	0	0	0	0
May-20	0	0	0	0	0
Jun-20	1037	1037	96	96	48
Jul-20	1037	1037	96	96	48
Aug-20	1037	1037	96	96	48
Sep-20	1037	1037	96	96	48
Oct-20	0	0	0	0	0
Nov-20	0	0	0	0	0
Dec-20	6338	6338	1073	1073	537
Jan-21	6338	6338	1073	1073	537
Feb-21	6338	6338	1073	1073	537
Mar-21	6338	6338	1073	1073	537
Apr-21	0	0	0	0	0
May-21	0	0	0	0	0
Jun-21	1037	1037	96	0	0
Jul-21	1037	1037	96	0	0
Aug-21	1037	1037	96	0	0
Sep-21	1037	1037	96	0	0
Oct-21	0	0	0	0	0
Nov-21	0	0	0	0	0
Dec-21	6338	6338	1073	0	0
Jan-22	6338	6338	1073	0	0
Feb-22	6338	6338	1073	0	0
Mar-22	6338	6338	1073	0	0
Apr-22	0	0	0	0	0
May-22	0	0	0	0	0
Jun-22	1037	1037	96	0	0
Jul-22	1037	1037	96	0	0
Aug-22	1037	1037	96	0	0
Sep-22	1037	1037	96	0	0
Oct-22	0	0	0	0	0
Nov-22	0	0	0	0	0
Dec-22	6338	6338	1073	0	0
Jan-23	85491	85491	33733	0	0
Feb-23	85491	85491	33733	0	0
Mar-23	85491	85491	33733	0	0
Apr-23	4762	4762	883	0	0

May-23	4762	4762	883	0	0
Jun-23	33400	33400	9258	0	0
Jul-23	33400	33400	9258	0	0
Aug-23	33400	33400	9258	0	0
Sep-23	33400	33400	9258	0	0
Oct-23	4762	4762	883	0	0
Nov-23	4762	4762	883	0	0
Dec-23	85491	85491	33733	0	0
Jan-24	355256	355256	203198	0	0
Feb-24	355256	355256	203198	0	0
Mar-24	355256	355256	203198	0	0
Apr-24	49810	49810	19127	0	0
May-24	49810	49810	19127	0	0
Jun-24	238269	238269	112758	0	0
Jul-24	238269	238269	112758	0	0
Aug-24	238269	238269	112758	0	0
Sep-24	238269	238269	112758	0	0
Oct-24	49810	49810	19127	0	0
Nov-24	49810	49810	19127	0	0
Dec-24	355256	355256	203198	0	0
Jan-25	355256	355256	203198	0	0
Feb-25	355256	355256	203198	0	0
Mar-25	355256	355256	203198	0	0
Apr-25	49810	49810	19127	0	0
May-25	49810	49810	19127	0	0
Jun-25	238269	238269	112758	0	0
Jul-25	238269	238269	112758	0	0
Aug-25	238269	238269	112758	0	0
Sep-25	238269	238269	112758	0	0
Oct-25	49810	49810	19127	0	0
Nov-25	49810	49810	19127	0	0
Dec-25	355256	355256	203198	0	0
Jan-26	355256	355256	203198	0	0
Feb-26	355256	355256	203198	0	0
Mar-26	355256	355256	203198	0	0
Apr-26	49810	49810	19127	0	0
May-26	49810	49810	19127	0	0
Jun-26	238269	238269	112758	0	0
Jul-26	238269	238269	112758	0	0
Aug-26	238269	238269	112758	0	0
Sep-26	238269	238269	112758	0	0
Oct-26	49810	49810	19127	0	0
Nov-26	49810	49810	19127	0	0
Dec-26	355256	355256	203198	0	0
Jan-27	355256	355256	203198	0	0
Feb-27	355256	355256	203198	0	0
Mar-27	355256	355256	203198	0	0
Apr-27	49810	49810	19127	0	0

May-27	49810	49810	19127	0	0
Jun-27	238269	238269	112758	0	0
Jul-27	238269	238269	112758	0	0
Aug-27	238269	238269	112758	0	0
Sep-27	238269	238269	112758	0	0
Oct-27	49810	49810	19127	0	0
Nov-27	49810	49810	19127	0	0
Dec-27	355256	355256	203198	0	0
Jan-28	355256	355256	203198	0	0
Feb-28	355256	355256	203198	0	0
Mar-28	355256	355256	203198	0	0
Apr-28	49810	49810	19127	0	0
May-28	49810	49810	19127	0	0
Jun-28	238269	238269	112758	0	0
Jul-28	238269	238269	112758	0	0
Aug-28	238269	238269	112758	0	0
Sep-28	238269	238269	112758	0	0
Oct-28	49810	49810	19127	0	0
Nov-28	49810	49810	19127	0	0
Dec-28	355256	355256	203198	0	0
Jan-29	355256	355256	203198	0	0
Feb-29	355256	355256	203198	0	0
Mar-29	355256	355256	203198	0	0
Apr-29	49810	49810	19127	0	0
May-29	49810	49810	19127	0	0
Jun-29	238269	238269	112758	0	0
Jul-29	238269	238269	112758	0	0
Aug-29	238269	238269	112758	0	0
Sep-29	238269	238269	112758	0	0
Oct-29	49810	49810	19127	0	0
Nov-29	49810	49810	19127	0	0
Dec-29	355256	355256	203198	0	0
Jan-30	355256	355256	203198	0	0
Feb-30	355256	355256	203198	0	0
Mar-30	355256	355256	203198	0	0
Apr-30	49810	49810	19127	0	0
May-30	49810	49810	19127	0	0
Jun-30	238269	238269	112758	0	0
Jul-30	238269	238269	112758	0	0
Aug-30	238269	238269	112758	0	0
Sep-30	238269	238269	112758	0	0
Oct-30	49810	49810	19127	0	0
Nov-30	49810	49810	19127	0	0
Dec-30	355256	355256	203198	0	0

Comment:	Bruce B Refurb Starts in 2018
Date	# Units I/S
Jan-09	[redacted]
Feb-09	
Mar-09	
Apr-09	
May-09	
Jun-09	
Jul-09	
Aug-09	
Sep-09	
Oct-09	
Nov-09	
Dec-09	
Jan-10	
Feb-10	
Mar-10	
Apr-10	
May-10	
Jun-10	
Jul-10	
Aug-10	
Sep-10	
Oct-10	
Nov-10	
Dec-10	
Jan-11	
Feb-11	
Mar-11	
Apr-11	
May-11	
Jun-11	
Jul-11	
Aug-11	
Sep-11	
Oct-11	
Nov-11	
Dec-11	
Jan-12	
Feb-12	
Mar-12	
Apr-12	
May-12	
Jun-12	

Comment:	Bruce B Refurb Starts in 2018
Date	# Units I/S
Jul-12	[redacted]
Aug-12	
Sep-12	
Oct-12	
Nov-12	
Dec-12	
Jan-13	
Feb-13	
Mar-13	
Apr-13	
May-13	
Jun-13	
Jul-13	
Aug-13	
Sep-13	
Oct-13	
Nov-13	
Dec-13	
Jan-14	8
Feb-14	8
Mar-14	8
Apr-14	8
May-14	8
Jun-14	8
Jul-14	8
Aug-14	8
Sep-14	8
Oct-14	8
Nov-14	8
Dec-14	8
Jan-15	8
Feb-15	8
Mar-15	8
Apr-15	8
May-15	8
Jun-15	8
Jul-15	8
Aug-15	8
Sep-15	8
Oct-15	8
Nov-15	8
Dec-15	8
Jan-16	8
Feb-16	8
Mar-16	8
Apr-16	8

Comment:	Bruce B Refurb Starts in 2018
Date	# Units I/S
May-16	8
Jun-16	8
Jul-16	8
Aug-16	8
Sep-16	8
Oct-16	8
Nov-16	8
Dec-16	8
Jan-17	8
Feb-17	8
Mar-17	8
Apr-17	8
May-17	8
Jun-17	8
Jul-17	8
Aug-17	8
Sep-17	8
Oct-17	8
Nov-17	8
Dec-17	8
Jan-18	7
Feb-18	7
Mar-18	7
Apr-18	7
May-18	7
Jun-18	7
Jul-18	7
Aug-18	7
Sep-18	7
Oct-18	7
Nov-18	7
Dec-18	7
Jan-19	6
Feb-19	6
Mar-19	6
Apr-19	6
May-19	6
Jun-19	6
Jul-19	6
Aug-19	6
Sep-19	6
Oct-19	6
Nov-19	6
Dec-19	6
Jan-20	6
Feb-20	6

Comment:	Bruce B Refurb Starts in 2018
Date	# Units I/S
Mar-20	6
Apr-20	6
May-20	6
Jun-20	6
Jul-20	6
Aug-20	6
Sep-20	6
Oct-20	6
Nov-20	6
Dec-20	6
Jan-21	6
Feb-21	6
Mar-21	6
Apr-21	6
May-21	6
Jun-21	6
Jul-21	6
Aug-21	6
Sep-21	6
Oct-21	6
Nov-21	6
Dec-21	6
Jan-22	6
Feb-22	6
Mar-22	6
Apr-22	6
May-22	6
Jun-22	6
Jul-22	6
Aug-22	6
Sep-22	6
Oct-22	6
Nov-22	6
Dec-22	6
Jan-23	7
Feb-23	7
Mar-23	7
Apr-23	7
May-23	7
Jun-23	7
Jul-23	7
Aug-23	7
Sep-23	7
Oct-23	7
Nov-23	7
Dec-23	7

Comment:	Bruce B Refurb Starts in 2018
Date	# Units I/S
Jan-24	8
Feb-24	8
Mar-24	8
Apr-24	8
May-24	8
Jun-24	8
Jul-24	8
Aug-24	8
Sep-24	8
Oct-24	8
Nov-24	8
Dec-24	8
Jan-25	8
Feb-25	8
Mar-25	8
Apr-25	8
May-25	8
Jun-25	8
Jul-25	8
Aug-25	8
Sep-25	8
Oct-25	8
Nov-25	8
Dec-25	8
Jan-26	8
Feb-26	8
Mar-26	8
Apr-26	8
May-26	8
Jun-26	8
Jul-26	8
Aug-26	8
Sep-26	8
Oct-26	8
Nov-26	8
Dec-26	8
Jan-27	8
Feb-27	8
Mar-27	8
Apr-27	8
May-27	8
Jun-27	8
Jul-27	8
Aug-27	8
Sep-27	8
Oct-27	8

Comment:	Bruce B Refurb Starts in 2018
Date	# Units I/S
Nov-27	8
Dec-27	8
Jan-28	8
Feb-28	8
Mar-28	8
Apr-28	8
May-28	8
Jun-28	8
Jul-28	8
Aug-28	8
Sep-28	8
Oct-28	8
Nov-28	8
Dec-28	8
Jan-29	8
Feb-29	8
Mar-29	8
Apr-29	8
May-29	8
Jun-29	8
Jul-29	8
Aug-29	8
Sep-29	8
Oct-29	8
Nov-29	8
Dec-29	8
Jan-30	8
Feb-30	8
Mar-30	8
Apr-30	8
May-30	8
Jun-30	8
Jul-30	8
Aug-30	8
Sep-30	8
Oct-30	8
Nov-30	8
Dec-30	8

Exhibit No. 31

Energy Probe INTERROGATORY #29 List 4

Interrogatory

Ref: Exh. B/T 3/S 1

Issue 1.1: Has the need for the proposed project been established?

Does the Applicant consider its public information notice(s) to be adequate and appropriate? If so, why? If not, why not?

Two large commercial wind farms inject into the transmission system serving Bruce – Amaranth and Kingsbridge. Amaranth has completed two years of service, and Kingsbridge is now about two weeks short of two years of service. In its first two individual years of service, Amaranth's output exceeded 50% capacity factor in 22% and 24% of the hours in the respective years. If transmission service to Amaranth was limited to 50% of the nameplate capacity of the farm, the output in year one would have been reduced by 4.6% of CF and the output in year two would have been reduced by 5.4% of CF. The bottled power lost to the customer would have been 27 GWh in year one and 32 GWh in year two. The market value of the replacement power to customers would have been about $1.2 million in year one and $1.5 million in year two.

Similarly, for Kingsbridge output exceeded 50% CF in 28% and 32% of the hours in the respective years. If transmission service to Kingsbridge was limited to 50% of the nameplate capacity of the farm, the output in year one would have been reduced by 6.4% of CF and the output in year to date two would have been reduced by 8.2% of CF. The bottled power lost to the customer would have been 22 GWh in year one and 28 GWh in year two. The market value of the replacement would have cost customers about $1 million and $1.3 million per year respectively.

The correlation coefficient for output from the two farms is approximately 75%. The correlation coefficient for output from wind power and nuclear in the region is much lower. This indicates that if transmission capacity to a wind generation region was limited to 50% of the nameplate, the bottle power lost to customers would be much less than estimated above.

Similar to wind power, the nuclear station at Bruce rarely generates at or close to its full nameplate capacity. Wind power in Ontario, like most regions of the northern hemisphere at our latitude, is subject to a very reliable drop in wind output during summer.

a) Please indicate the net consumer impact, including transmission cost and replacement generation cost, of sizing the peak summer transmission capacity with firm capacity to serve 50% of the expected nameplate capacity of wind power in the Bruce region and 7/8ths or 87.5% CF of the expected nameplate nuclear capacity.

b) Please provide any analysis done by Hydro One or the OPA analyzing the economically optimal sizing of transmission capacity serving the Bruce region.

c) Please confirm that all generation figures in Figure 1 on Page 2 reflect forecast resource nameplate capacity without any adjustment for reliability.

Response

From the Preamble to this Interrogatory the inferred cost of wind generation appears to be approximately $45/MWh. OPA does not consider this to be a realistic assumption.

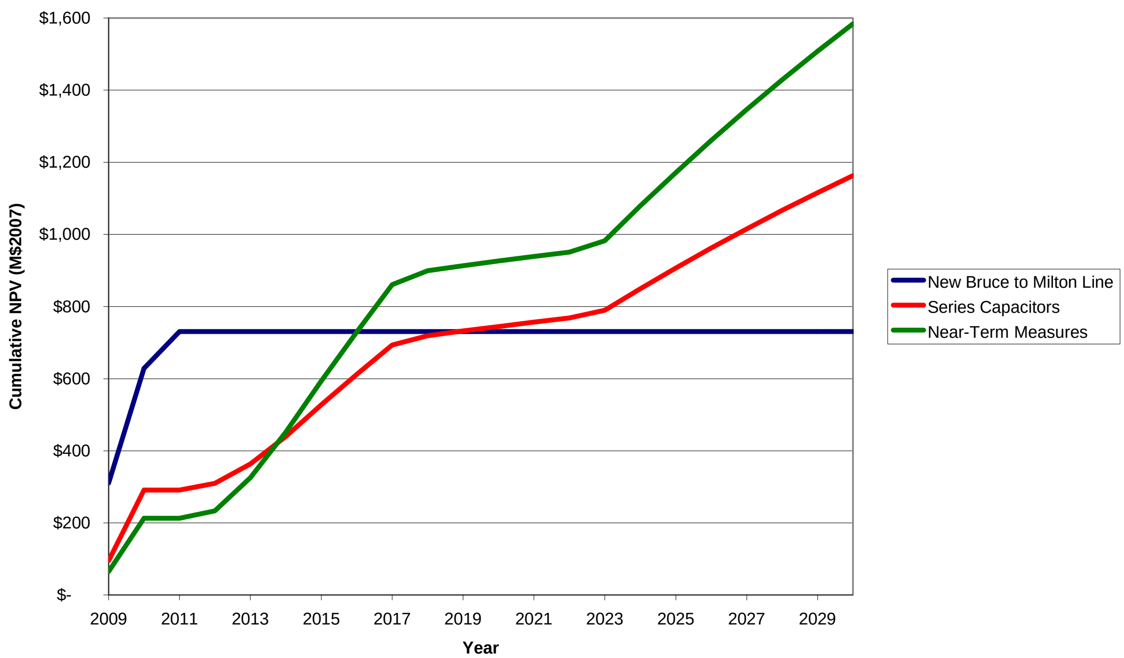
a) The transmission capability proposed in the Interrogatory is 6,450 MW (50% of 1,700 MW of Wind + 87.5% of 6,400 MW of Nuclear = 6,450 MW). This is approximately equal to the capability of the series capacitor option (6,326 MW, please refer to the response to Pollution Probe Interrogatory 16). The OPA's financial evaluation model is discussed in Pollution Probe Interrogatory 47. The model takes into account the variability of wind and nuclear generation as well as transmission capability. The results of the OPA's financial evaluation of the series capacitors option, as compared to the proposed Bruce to Milton line, are discussed in the response to Board Staff Interrogatory 3.4. OPA has determined that by the end of the study period in 2030, the net present value of costs associated with implementing a series capacitors option, exceeds the net present value of costs associated with the Bruce to Milton line by over $400 million in present dollars. This does not take into account the technical and operation complexities that are also expected to occur with a series capacitors solution.

b) It is not possible to "size" the transmission capability to a specific value. Improvements to the transmission system increase transmission capability in steps. All of the new line alternatives (such as Bruce to Essa, HVDC, etc.) provide equal to or less than the transmission capability of the proposed Bruce to Milton line for a higher capital cost. Therefore, the alternatives involving new lines were not assessed in terms of economics because they will result in a higher cost for the above reasons. The financial evaluation that was conducted analyzed three different steps in transmission capability out of the Bruce Area:

1. Near-Term Measures
2. Series Capacitors
3. Proposed Bruce to Milton Line

The financial evaluation provided in the response to Board Staff Interrogatory 3.4 has been expanded to include the near-term measures option (see graph shown).

Cumulative Net Present Value of Costs for the Bruce to Milton Line, Series Capacitors and the Near-Term Measures Options



Initially, the proposed Bruce to Milton line has the highest cost due to its larger upfront capital costs as compared to the series capacitors or near-term measures options. However, the costs of the increased undelivered energy and losses from employing either the Series Capacitors option or the Near-Term Measures option make the proposed Bruce to Milton line significantly less expensive in the long-run. As shown in the Chart above by comparing the levels of the respective lines at far right hand side of the chart, the cumulative net present value of costs for the Bruce to Milton Project is $400 million less than the Series Capacitors option and $900 million less than the Near Term Measures option over the study period.

c) Confirmed. The generation forecast in Figure 1 is based on nameplate capacity of forecasted resources.

Exhibit No. 32

Pollution Probe INTERROGATORY # 9 List 1

Interrogatory

Issue Number: 1.0
Issue: Project Need and Justification

Ref. B/Tab 1/Sch 1, B/Tab4/Sch 4 and K/Tab 1

If the proposed Bruce to Milton high-voltage transmission line is not approved, please provide the OPA's estimates of the net present value (in 2007$) of Bruce Area's locked-in electricity for each year from 2012 to 2036 inclusive under each of the following scenarios:

a) The implementation of Hydro One's near-term measures (i.e. dynamic and static reactive resources and upgrading the Hanover to Orangeville line);

b) The implementation of Scenario A plus the expansion of the Bruce special protection system;

c) The implementation of Scenario B plus the installation of series capacitors;

d) The implementation of Scenario C if the Bruce B nuclear reactors are not re-built at the end of their service lives and no new nuclear capacity is installed in the Bruce Area; and

e) The implementation of Scenario C if the Bruce B nuclear reactors are not re-built at the end of their service lives, no new nuclear capacity is installed in the Bruce Area, and the average annual capacity factor of the Bruce Nuclear Station is 10% lower than the OPA's current estimate.

If the OPA's discount rate is not the same as the discount rate used by Hydro One to calculate the net present value of the cost for the proposed Bruce to Milton transmission line, please provide the OPA's net present value calculations using:

a) the OPA's discount rate; and

b) Hydro One's discount rate.

With respect to these net present value calculations, please provide all of the OPA's input and other assumptions, and please break-out the net present values for each year from 2012 to 2036 inclusive by the following generation categories:

a) existing Bruce A nuclear reactors;

b) existing Bruce B nuclear reactors;

c) re-built Bruce B nuclear reactors;

d) new Bruce nuclear reactors;

e) existing wind generation;

f) committed wind generation;

g) uncommitted wind generation; and

h) other.

Please also provide an electronic copy of the OPA's discounted cash flow model which will allow the Board and interveners to vary the input and other assumptions and recalculate these net present values.

Response

The Bruce Area has been studied by the OPA to 2030 and information to that date is shown below instead of to 2036 as requested in the Interrogatory.

As explained in the evidence in Exhibit B, Tab 6, Schedule 5, Appendix 1, pg. 3, the proposed project is non-discretionary and therefore does not need to be evaluated on a cash flow basis. However, OPA has created a cash flow model to respond to this and other Interrogatories. The model uses the methodology and assumptions outlined in the response to Interrogatory 7 from Pollution Probe.

In addition to these, the following assumptions were made in order to respond to this question:

1. The cost of undelivered energy is equal to the cost of the replacement energy.
2. Energy costs are those in the OEB published TRC Guide, Table 11.
3. A real discount rate of 4% was assumed by the OPA.

The results using both OPA's discount rate and Hydro One's discount rate are provided below. Note that the OPA uses a real discount rate of 4%, which is an estimate of the social discount rate. This is different from Hydro One's discount rate, which is an after-tax, nominal rate of 5.47% based on its cost of capital, as shown in the Nov. 30th, 2007 update to the evidence at Exhibit B/T4/S4/p.5. When discounting unescalated, non-utility cash flows such as undelivered energy, use of a real social discount rate is advised rather than a utility-specific, nominal, after-tax discount rate.

The results for 2012 to 2030 are shown in the table below. Note that it is not possible to assign the undelivered energy costs to the categories requested. Also note that the results for part (a) and part (b) are identical. This relates to the assumption made regarding the use of generation rejection (G/R). Please see the response to Pollution Probe Interrogatory #7.

a) See tables below.
b) See tables below.
c) See tables below.
d) See tables below.
e) See tables below.

A copy of the requested model is provided, as Attachment 1, subject to the conditions described in the OPA's letter to the Board dated March 5, 2008.

Undelivered Energy Cost (M$2007) (OPA Discount Rate)

Year	Part a)	Part b)	Part c)	Part d)	Part e)
2012	3	3	0	0	0
2013	69	69	29	29	12
2014	105	105	52	52	23
2015	120	120	63	63	29
2016	115	115	60	60	28
2017	110	110	58	58	26
2018	20	20	7	55	25
2019	1	1	0	53	24
2020	1	1	0	4	2
2021	1	1	0	0	0
2022	1	1	0	0	0
2023	17	17	6	0	0
2024	82	82	43	0	0
2025	78	78	41	0	0
2026	75	75	39	0	0
2027	72	72	38	0	0
2028	69	69	36	0	0
2029	67	67	35	0	0
2030	64	64	34	0	0

Undelivered Energy Cost (M$2007) (Hydro One Discount Rate)

Year	Part a)	Part b)	Part c)	Part d)	Part e)
2012	3	3	0	0	0
2013	64	64	26	26	11
2014	95	95	47	47	21
2015	107	107	56	56	26
2016	101	101	53	53	24
2017	96	96	50	50	23
2018	17	17	6	47	22
2019	1	1	0	45	20
2020	1	1	0	3	2
2021	1	1	0	0	0
2022	1	1	0	0	0
2023	13	13	5	0	0
2024	64	64	34	0	0
2025	61	61	32	0	0
2026	58	58	30	0	0
2027	55	55	29	0	0
2028	52	52	27	0	0
2029	49	49	26	0	0
2030	47	47	24	0	0