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Susan Frank
Vice President and Chief Regulatory Officer
Regulatory Affairs

BY COURIER

March 10, 2008

Ms. Kirsten Walli
Secretary
Ontario Energy Board
Suite 2700, 2300 Yonge Street
P.O. Box 2319
Toronto, ON M4P 1E4

Dear Ms. Walli:

EB-2007-0050 – Hydro One Networks' Section 92 Bruce - Milton Transmission Reinforcement Application – Hydro One Networks' Response to Interrogatory Questions from OEB Staff

I am attaching an electronic copy of the responses to the interrogatory questions of OEB Staff. Paper copies plus a CD version will be provided tomorrow.

Sincerely,

ORIGINAL SIGNED BY ANDREW PORAY FOR SUSAN FRANK

Susan Frank

c. EB-2007-0050 Intervenors
M. Heinz, Ontario Power Authority

Ontario Energy Board (Board Staff) INTERROGATORY #1.1 List 1

Interrogatory

Issue Number: 1.1
Issue: Has the need for the proposed project been established?

Ref. (a) Press Release by Bruce Power in Tiverton, Ontario dated August 29, 2007 in regard to "Bruce Power and the Ontario Power Authority (OPA) have amended their existing Bruce A agreement to allow for the complete refurbishment of Unit 4.

Ref. (b) B/Tab 6/Sch5/Appendix 2(Letter dated Dec 22, 2006 from OPA to Hydro One, IESO, and Bruce Power)/ p. 1/last paragraph

Preamble:

(a) Ref (a) explains the additional scope of work to be carried out under the amendment to the agreement on unit 4. The announcement further indicated that Bruce Power expects to complete the work on Units 3 and 4 by 2013.

(b) Ref (b) states in part:
"….Bruce Power is refurbishing and returning into service the two "laid-up" generating units, Unit 1 and 2, at the Bruce A nuclear plant. These units, each rated at 725 MW are scheduled to be returned into service in 2009……Coincidental to the return of the two Bruce units, Bruce Power is scheduling the outage of other units at the Bruce A plant for extended maintenance work from 2009 t0 2011. Thus in effect, an equivalent of one Bruce unit is added between 2009 and end of 2011, and two units thereafter

Questions:

(i) Does the amended agreement [see Ref.(a)] between Bruce Power and the OPA affect Hydro One's assessment of the amount and timing of additional transmission capacity required between Bruce and Milton?

(ii) In Ref. (b) it is indicated that unite 3 and 4 will be taken out of service, one unit at a time between 2009 and 2011. Please confirm from OPA and Bruce Power whether under the amended agreement units 3 and 4 will be taken out of service one at a time between 2009 and 2013 or both units 3 and 4 will be out of service for the entire period between 2009 and 2013.

(iii) If there are expected changes in the amount or timing of new transmission capacity, please indicate when Hydro One expects to file updated evidence.

Response

(i) The amended agreement between Bruce Power and the OPA does not affect the timing for the need or the amount of additional transmission capability required between Bruce and Milton. There will be a shortfall in transmission capability to deliver the added wind and nuclear generation in the Bruce area starting in 2009. Please refer to the Day 1 Technical Conference Presentation slides 23 and 24 (Exhibit KT.1). Also, refer to the updated evidence as explained in part (iii) below.

(ii) Yes, Hydro One has confirmed with the OPA and the IESO that Units 3 and 4 will be taken out of service in or after 2009, refurbished, and then returned to service by 2013. Also, under both the original Bruce Power Refurbishment Implementation Agreement and the Amended Agreement, the refurbishment work on the two units is staggered; however, there are periods when both units are not in-service.

(iii) There are no expected changes in the amount or timing of new transmission capacity as a result of the amendment to the Bruce refurbishment contract.

An update to the evidence was filed on November 30, 2007 for Exhibit B, Tab 6, Schedule 5, Appendix 1. This update inadvertently omitted certain changes to the total generation capacity in the Bruce area. A corrected exhibit is filed as Attachment A to this response.

Attachment A

Exhibit B, Tab 6, Schedule 5, Appendix 1

OPA Analysis of Need for Proposed Facilities.

APPENDIX 1

OPA Analysis of Need for Proposed Facilities.

Appendix 1

OPA ANALYSIS OF
NEED FOR PROPOSED FACILITIES

1.0 BACKGROUND

Under the *Electricity Act, 1998* (the "Act"), the OPA has the responsibility for long-term power system planning in Ontario. In accordance with the Act, the OPA is required to periodically develop an Integrated Power System Plan (IPSP). In developing the IPSP, the OPA must follow directives issued by the Minister of Energy setting out goals to be achieved during the period covered by the plan.

The Minister of Energy issued a directive to the OPA dated June 13, 2006, setting goals that the OPA must plan to meet in its first IPSP. These include the goal of increasing the installed capacity of renewable energy sources by 2,700 MW from the 2003 base by 2010 and increasing "the total capacity of renewable energy sources used in Ontario to 15,700 MW by 2025". The directive further requires the OPA to plan to strengthen the transmission system in order to:

- Enable the achievement of the supply mix goals set out in this directive;
- Facilitate the development and use of renewable energy resources such as wind power, hydroelectric power and biomass in parts of the Province where the most significant development opportunities exist;
- Promote system efficiency and congestion reduction and facilitate the integration of new supply, all in a manner consistent with the need to cost-effectively maintain system reliability.

Consistent with its policy direction, the Government of Ontario also undertook the Renewable Energy Supply procurements (RES I and II), which led to the execution of several contracts for wind projects in the Bruce area. By a directive dated November 7, 2005 (found at Exhibit B, Tab 6, Schedule 5, Appendix 8), the OPA was directed to assume the responsibilities of the Crown under the contracts entered into as a result of the RES I procurement process. By a directive dated November 16, 2005 (found at Exhibit B, Tab 6, Schedule 5, Appendix 9), the OPA was directed to enter into contracts with the proponents selected under the RES II procurement process. A schedule of the contracts with the OPA for wind projects in the Bruce area that resulted from the RES I and II procurement processes is found at Exhibit B, Tab 6, Schedule 5, Appendix 10.

Further, the Minister of Energy issued a directive to the OPA dated March 21, 2006 (found at Exhibit B, Tab 6, Schedule 5, Appendix 11) to develop a standard offer program for renewable energy projects in the Province. The OPA has commenced the implementation of this program; but in light of the system constraints in the Bruce area, the OPA has decided to not issue contracts for developments in this area until there is sufficient transmission capacity available or there are other means to manage the limited transmission capacity.

The Government of Ontario also negotiated an agreement with Bruce Power for the refurbishment and return to service of two idle nuclear units, Unit 1 and Unit 2, at the Bruce A plant, the purchase of the power from these units, and the further refurbishment of Units 3 and 4 at Bruce A. The Minister of Energy issued a directive to the OPA dated October 14, 2005 (found at Exhibit B, Tab 6, Schedule 5, Appendix 12) to execute this contract.

On August 29, 2007, the Ontario Power Authority (OPA) announced an agreement with Bruce Power to amend the existing contract providing for the complete refurbishment of Bruce A Unit 4—rather than the more limited steam generator replacement program originally planned. The additional work will lengthen the life of Unit 4 by nearly 20 years to 2036, reducing Ontario's need for new build nuclear facilities. In so doing, the province secures 20% more long-term electricity supply than originally contracted. The agreement is consistent with the Minister of Energy's June 2006 Directive to the OPA limiting the future use of nuclear power to today's installed capacity level of 14,000 megawatts. As a result of the amendment to the agreement, the in-service date for the last of the eight units at Bruce has moved from 2012 to 2013.

The proposed Bruce to Milton transmission reinforcement project will help to achieve the Government policy goals and enable the fulfillment of the aforementioned resource development commitments in the Bruce area that were initiated by the Government prior to the development of the IPSP.

The availability of the committed resources in the Bruce area and the means to deliver those resources to the Ontario power grid is an underlying assumption in the development of the IPSP. Beyond the existing and committed resources in the area, the assessment done to date for the IPSP has identified significant potential, about 1000 MW, for further renewable energy resource development in the Bruce area. Developing this potential, which would be facilitated by the proposed project, will contribute to meeting the Government's renewable energy resource target.

2.0 NEED FOR THE PROJECT

2.1 Classification of Need

The OEB's Filing Requirements for Transmission and Distribution Applications (EB-2006-0170) provide in section 5.2 for transmission projects proposed in an application under section 92 of the *Ontario Energy Board Act* prior to the approval of an Integrated Power System Plan, to be categorized first into Development, Connection or Sustainment. In this case, the project is a development project because the proposed facilities provide for additional system capacity and maintain reliability and quality of electricity supply.

Once this first categorization is complete, the project must then be categorized as either a non-discretionary or discretionary project. A non-discretionary project is described as a "must do" project, the need for which is determined beyond the control of the Applicant. This project is considered to be non-discretionary because the proposed facilities are needed to achieve objectives of the Government of Ontario that are prescribed in the directives referred to in Section 1 – Background.

2.2 Project Need

As detailed in Section 1 – Background, about 1,500 MW of nuclear and 675 MW of wind generation capacity was contracted for in the Bruce area in the past three years. In addition, there are 15 MW of wind generation already in operation and 10 MW contracted from the Renewable Energy Standard Offer Program. These resources contribute to meeting the Government's electricity policy objectives. With these resources, the OPA estimates that the total generation available in the Bruce area will total about 5,500 MW by 2009 and 7,100 MW by early 2013. With the additional wind generation opportunities of about 1,000 MW also identified by the OPA in the area, the total generation in the Bruce area could reach 8,100 MW by the middle of the next decade.

As indicated in the OPA's IPSP discussion papers (see Exhibit B, Tab 6, Schedule 5, Appendices 5 and 6), the present transmission system has the capability to transmit about 5,000 MW of the generation from the Bruce area. This capability is established by the IESO in setting its operating limits.

Hydro One, as set out in its Transmission Licence, must comply with the technical and performance requirements of the Transmission System Code ("TSC") and various regulatory bodies, including the Northeastern Power Coordinating Council ("NPCC") and the North American Electric Reliability Council ("NERC"). These requirements include the duties of maintaining acceptable voltages, keeping equipment operating within established ratings, and maintaining system stability, both during normal operation and under recognized contingency conditions on the transmission system.

Based on these requirements, the shortfall in transmission capacity as related to the available resource in the Bruce area is forecast to be about 500 MW by 2009 and 2,100 MW by 2013, and could well be over 3,100 MW afterward should the renewable energy potential continue to develop in the area. Given the expected shortfall between transmission capability and forecast available generating capacity in the Bruce area, there is a need to reinforce the transmission system out of the Bruce area as early as possible both to permit full deployment of the committed generating resources and to enable the development of potential new renewable energy resources in the Bruce area consistent with Government policies and directives.

The OPA's conclusions are supported by the IESO. In its June 2006 Ontario Reliability Outlook and its System Impact Assessment (SIA) for the proposed facilities, the IESO identified the need for reinforcement of the transmission system in order to effectively extract the committed and proposed additional generation capacity from the Bruce area and to maintain reliable performance of the transmission system consistent with applicable reliability planning standards and guidelines. The SIA also confirms that the proposed facilities would be adequate to meet the applicable reliability standards and guidelines and will not adversely impact the IESO-controlled grid. The SIA is filed hereto as Exhibit B, Tab 6, Schedule 2.

Ontario Energy Board (Board Staff) INTERROGATORY #1.2 List 1

Interrogatory

Issue Number: 1.1
Issue: Has the need for the proposed project been established?

Ref. (a) A/Tab 2/Sch 1/pp. 1, 2 and 3

Ref. (b) B/Tab 1/Sch 3/pp. 1 and 2

Ref. (c) OEB Filing Requirements for Transmission and Distribution Applications (November 14, 2006)/section 5.2.2/pp. 33 and 34

Preamble:

(a) In Ref.(a) and Ref.(b), the Applicant states that the project is needed in order to accommodate additional Bruce area generation and to satisfy IESO reliability requirements.

(b) In Ref.(c), Section 5.2.2 "Project Need" outlines the various categories of triggers for Non-discretionary projects as well as examples of projects that are classed as discretionary projects.

Questions:

With reference to Preamble (b), and Ref. (c), please indicate which categories of need that this project intended to meet? In the response, please provide a narrative explaining the justification for the category or categories of need identified.

Response

An explanation of the project's classification is found at Exhibit B, Tab 6, Schedule 5, Appendix 1. The proposed project is non-discretionary because it is required to meet Government objectives including:

1. Meeting the IPSP target of 15,700 MW of installed capacity from renewable energy sources in a cost effective and economically prudent manner (see "Directive to OPA on IPSP Goals", attached to application as Exhibit B Tab 6 Schedule 5 Appendix 7).

2. Procurement of renewable resources in Ontario through Renewable Energy Supply projects (RES I and RES II) (see Exhibit B Tab 6 Schedule 5 Appendices 7 to 10).

3. Initiating a Standard Offer Program (SOP) for the development of renewable energy projects in the Province (see Exhibit B Tab 6 Schedule 5 Appendix 11).

4. The execution of the Bruce A refurbishment contract (see Exhibit B Tab 6 Schedule 5 Appendix 12).

Ontario Energy Board (Board Staff) INTERROGATORY #1.3 List 1

Interrogatory

Issue Number: 1.1
Issue: Has the need for the proposed project been established?

Ref B/Tab 1/Sch 1/pp. 4 and 5

Preamble:

(a)The noted Ref. it is stated that generation from the Bruce Power Complex and the general Bruce area is currently delivered to south/central Ontario via the following transmission facilities:

- the 500 kV Bruce - Milton SS and Claireville TS double circuit transmission line, B561M and B560V;
- the 500 kV Bruce - Longwood TS double circuit transmission line, B562L and B563L;
- the 230 kV Bruce - Orangeville TS double circuit transmission line, B4V and B5V;
- the 230 kV Bruce - Detweiler TS double circuit transmission line, B22D and B23D; and,
- the 230 kV Bruce - Owen Sound TS double circuit transmission line, B27S and B28S.

It is also indicated that these circuits have only about 5,000 MW (5,060 MW) of transmission capacity to deliver the output from the Bruce Power complex and from nearby wind generation.

(b)The full output of the Bruce A and the Bruce B complex were in the order of 6,560 MW (4 × 890 MW + 4 × 750 MW) prior to the decision in the mid 1990s to lay up 2 of the Bruce A units of about 1500 MW of Capacity.

Questions:

(i) Did Hydro One carry out analysis in regard to how the transmission facilities managed to deliver the entire capacity of the Bruce area generating facilities for that long period of time (period from in-service of all 8 generating units (6560

MW) in the Bruce Complex and the transmission lines that evacuated that generation until the laying up the two units)? If so please provide such analysis. If not, please provide explanation why Hydro One felt such analysis is not needed.

(ii) Would it be possible to carry out such analysis? And if so, how long would it take to provide it?

(iii) In carrying out the analysis identified in (i) above, if this is workable, please explain what has occurred to degrade the transmission delivery capability to 5,060 MW (a reduction of approximately 1,500MW)?

Response

(i) Yes, however the analysis conducted was not limited to one specific report. As was explained during the Technical Conference, existing transmission facilities from the Bruce area are not adequate to meet the identified need. The major causes of the difference between the capability of the current system and the system that had transferred generation from all eight Bruce Units are:

1. The Southwestern Ontario transmission system in the 1980's experienced a predominately east-to-west flow. Forecast flow is predominantly west to east. Several factors are causing this change in flow pattern, including additional generation in Windsor and Sarnia and higher loads in the GTA and Southwestern Ontario.

2. The dominating failure mode of the 1980's system was due to generation plant instability. Today and in the future, the system's expected dominating failure mode in Southwestern Ontario is a voltage instability event. This has a very different characteristic than a plant or machine mode instability. As a result the reactive requirements on the transmission system, especially in the GTA and Southwestern Ontario, have an impact on the transmission capability of the Bruce Area. Also, other factors, such as the number of generators in service, would have an impact on the Bruce Area transmission capability due to today's dominant failure mode.

3. During the 1980's, there were three Heavy Water Plants in operation at the Bruce Nuclear Facilities. These had a large load of approximately 300 MW, and created a significant reduction on the net generation flowing away from the Bruce Nuclear Facilities. The Heavy Water Plants are no longer in operation. As a result there is a greater amount of generation at the Bruce Nuclear Facilities and this now needs to be transmitted to loads elsewhere on the grid.

Please also refer to slide 25 of the Day 1 Technical Conference Presentation (Exhibit KT.1) for an overview of the historical capability of the system.

(ii) Please refer to Response (i) above.

(iii) Please refer to Response (i) above.

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:

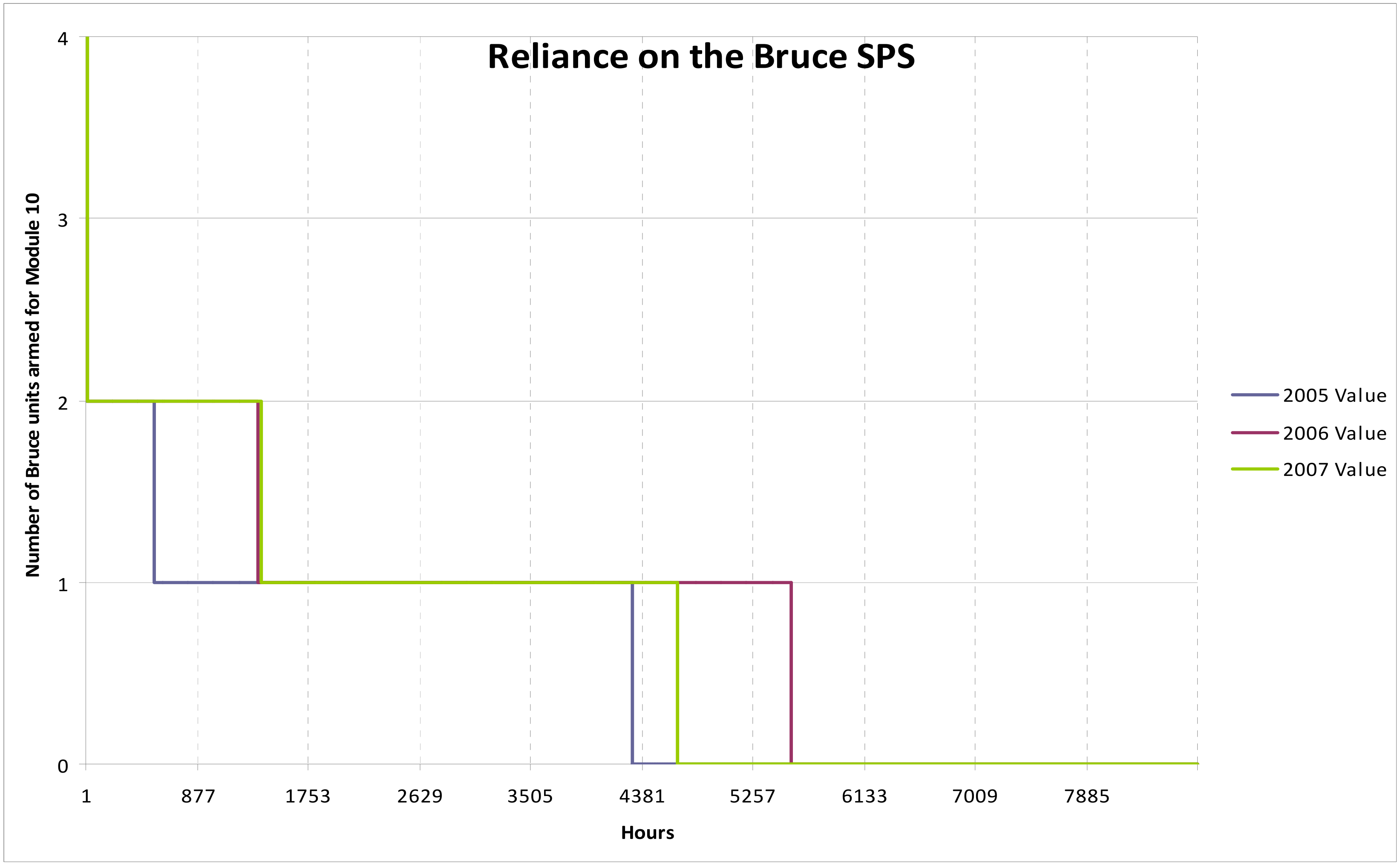
Generation rejection: Pre-selected generating units at Bruce A and/or Bruce B are automatically disconnected. The scheme has the capability of rejecting any of the eight units and multiple units can be selected for one event. A modification to enable the rejection of transmission-connected wind farms 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
0
1
2
3
4
1
877
1753
2629
3505
4381
5257
6133
7009
7885
Hours
2005 Value
2006 Value
2007 Value

Ontario Energy Board (Board Staff) INTERROGATORY #1.5 List 1

Interrogatory

Issue Number: 1.1
Issue: Has the need for the proposed project been established?

Ref

(a) B/Tab 6/Sch5/Appendix 1 (OPA Analysis of Need For the Proposed Facilities)/Section 2.2/pp. 3 to 5

(b) Filing Requirements for Transmission and Distribution Applications (November 14, 2006)/p. 35/section 5.3.2/3rd paragraph

Preamble:

Congestion reduction attributable to the proposed project is one of the important benefits that need to be assessed on an annual basis over the period 2012 to 2016 inclusive i.e., covering a period of 5 years.

Questions:

(i) Did Hydro One carry out such analysis? If so please provide the results. If not please provide the reasons such analysis was not carried out.

(ii) If a study as prescribed in (i) above was not carried out, Is it possible to provide the results of such analysis by October 15 for the technical conference? If not please indicate when such results can be made available.

(iii) In carrying out the analysis outlined above, please assume:

a. The Near Term measures are completed including the enhancements of the 230 kV circuits and installation of Shunt Capacitors and SVCs in the various stations as outlined in the evidence;

b. Please reflect Hydro One’s response to Board staff Question No. 1 above in regard to the delay of the return to service of Bruce Units 3 and 4 to 2013, as well as reflecting whether in effect, an equivalent of one Bruce unit is added between 2009 and end of 2013, and two units thereafter; or in effect there is no new generation capacity addition at Bruce A until end of 2013.

c. Reflect the latest expectations regarding the potential 1000 MW of wind, to ensure that what is simulated in the assessment is reflective of the latest information.

(iv) Repeat the same steps above i.e., steps (ii), and (iii) but with both Interim Measures in-service i.e., the GR scheme and the series compensation as outlined in Ref. (a), as well as assuming that the new double circuit 500 kV transmission line is not in service.

Response

Yes, OPA carried out a congestion study for the Bruce system.

The requested information is included as part of Hydro One's Response to Pollution Probe Interrogatory 7.

Ontario Energy Board (Board Staff) INTERROGATORY #1.6 List 1

Interrogatory

Issue Number: 1.1
Issue: Has the need for the proposed project been established?

Ref.(a) Exh. B/T 6/S 5/Appendix 1 (OPA Analysis of Need For the Proposed Facilities)/Section 2.2/p.4 /lines 21 29
Ref.(b) Exh. B/T 6/S 4(the Ontario Reliability Outlook)/p. 5

Preamble:

(a) In Ref.(a), OPA concludes that the transmission capacity shortfall would be 500 MW by 2009, 2,100 MW by 2012 and could be over 3,100 MW (assuming the 1000 MW of wind generation would be developed).

(b) In Ref.(b), the evidence on the capacity factor of wind generation suggests that :
- a winter capacity factor for a wind farm would be in the order of 40%
- a summer capacity factor would be in the order of 20% (given that Ref.(b) indicate that the average annual Capacity Factor of all wind farms was 25 %)

Questions:

(i) Please confirm that the OPA translated the committed wind capacity of 725 MW as well as the potential long term wind of 1000 MW assuming a capacity factor of 100 %;

(ii) Please confirm that given the performance of wind generation it is reasonable to assume a capacity factor of about 20% for summer and 40% for winter, which reflect the capacity factors shown in Ref.(b).

(iii) Please produce two "Power Flow Duration Curves or (PFDC)", one for Winter (5 months, Nov to March) and one for Summer (7 months, April to October), reflecing

- the total generation in the Bruce Complex [Bruce A Units (1 and 2) back in service in 2009, with units 3 and 4 taken out one at a time till 2011]
- the committed wind generation of 725 MW as well as the potential wind generation of 1000 MW, both assuming Capacity Factors of 20% in Summer and 40% in Winter.

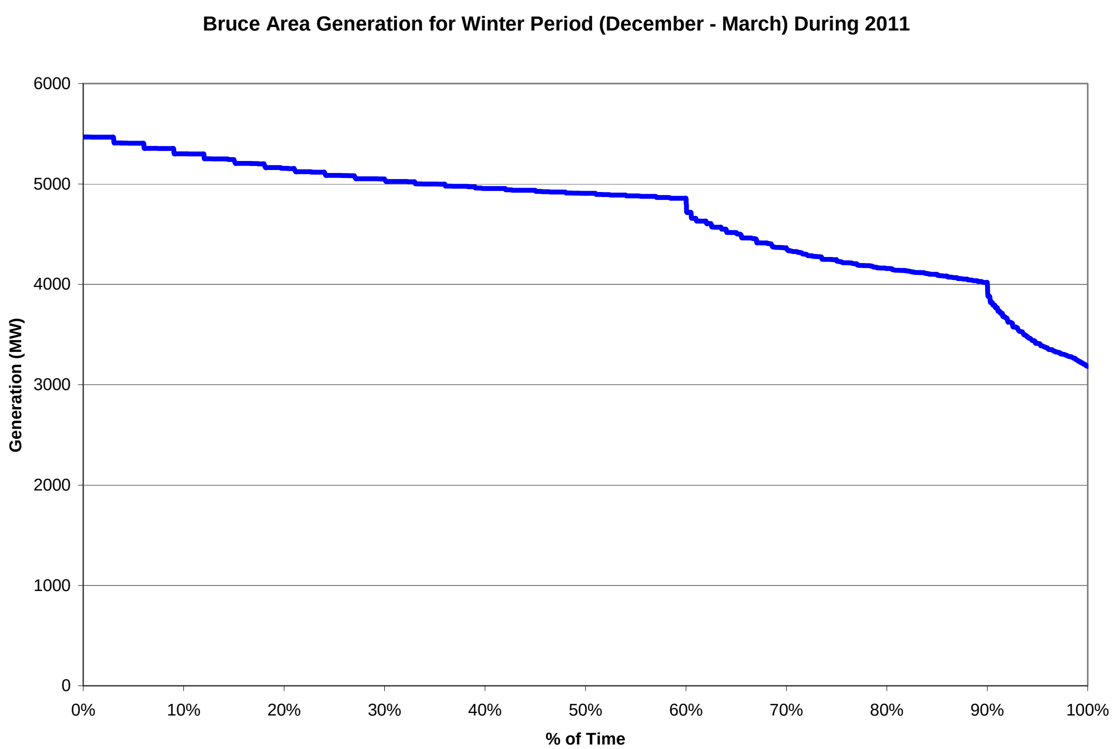
(iv) Based on the results of step (iii), please provide estimates of the shortfall for the summer and winter as defined above in MW in 2009 and in 2012 (with and without the 1000 MW of wind potential).

Response

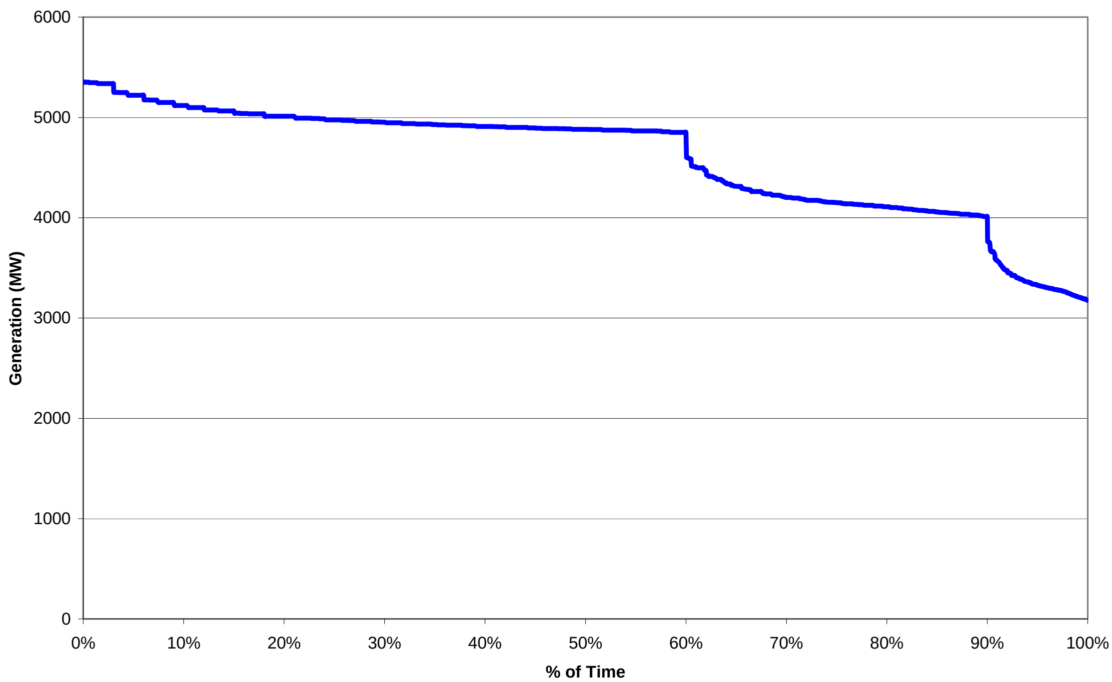
(i) Confirmed. The OPA referred to installed capacities when describing 700 MW of committed wind generation as found in the Updated Evidence dated November 30, 2007 (Exhibit B, Tab 6, Schedule 5, Appendix 1). This revised the previous 725 MW of existing and committed wind generation capacity in the Bruce area to 700 MW.

(ii) The average energy produced from the Bruce wind generators during the summer period (June to Sept) for wind in the Bruce area is approximately 20% of installed capacity (average MW divided by installed MW capacity). Similarly, the average energy generation during the winter period (Dec to March) is approximately 34% of installed capacity. The average for the entire year is approximately 29% of installed capacity.

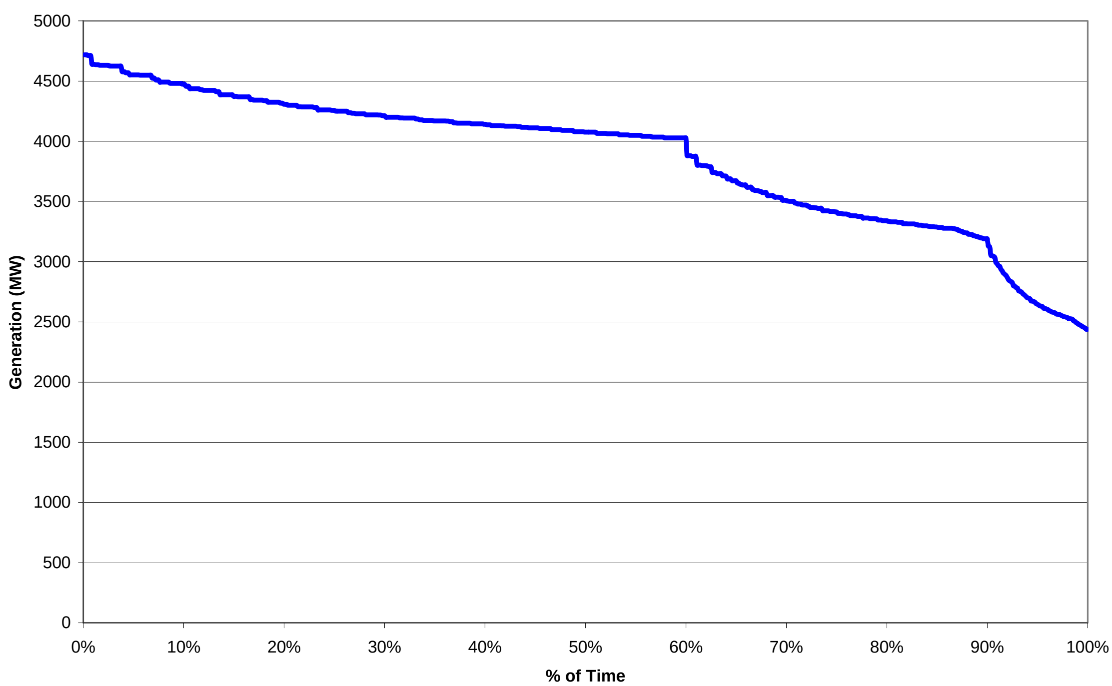
(iii) Duration curves were produced for three different seasons (Winter, Summer and Shoulder). They were done for the year 2011 reflecting the fact that both nuclear and wind generation are not constant. See graphs below:



Bruce Area Generation for Summer Period (June - September) During 2011



Bruce Area Generation for Shoulder Period (May, June, October and November) During 2011



(iv) Transmission capability is planned based on peak generation and load. It is not appropriate to plan only for averages. In the case of a system that consists of only nuclear and wind generation, it is assumed that nuclear is generating nearly constantly at its maximum output and that wind varies from a minimum output of 0 to a maximum of its installed capacity. The peak condition for this system is when the wind is generating at the maximum of its installed capacity. Therefore, the peak generation that defines the need is the sum of the installed capacity of the nuclear and wind generation. On this basis, the shortfall in transmission capability is the difference between the installed capacity and the transmission capability. As explained in the Day 1 Technical Conference Presentation (Exhibit KT.1) at slides 23 and 24, there is a shortfall of approximately 3,100 MW. A more detailed discussion of planning transmission for a system that consists of nuclear and wind generation is available on pages 159 to 161 of the technical conference transcript.

Ontario Energy Board (Board Staff) INTERROGATORY #1.7 List 1

Interrogatory

Issue Number: 1.3
Issue: 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?

Ref B/Tab 6/Sch 2 (IESO System Impact Assessment Report)/Sec. 9.1.2 /p. 9 and Diagram 5

Preamble:

With the preferred alternative in place and with the system loaded to projected 2012 levels and all circuits in-service as per the load flow sketch Diagram 5, the new double circuit Bruce Milton line and the existing Bruce Milton/Claireville double circuit lines (B560V and B561V) are projected to each carry 37 % of the Bruce area to GTA load flow and the adjacent 230kV double circuit lines (B4V and B5V) are projected to carry 9% of the load flow.

Questions:

(i) Did Hydro One perform an evaluation of the prudency of the proposed project that will transmit about 83% of the Bruce-to- GTA load flow along one corridor when the other three available corridors are proposed to deliver only 9%, 7% and 1% of this load flow respectively? If so provide this evaluation. If not, please provide the reasons for not carrying out such an evaluation?

(ii) If the evaluation discussed in (i) above was not carried out, can Hydro One provide such an evaluation by October 15 for the technical conference.

Response

(i) It is not clear what is meant by “prudency of the proposed project…” If this meant to refer to the impact of the project on the performance of the power system then no, Hydro One did not carry out such studies (i.e., power flow distribution). A detailed reliability analysis of the proposed project was carried out by the IESO in the course of conducting the System Impact Assessment (“SIA”), which included a careful review of the power flow distribution over the circuits delivering power from the Bruce Area to the GTA. The purpose of the SIA was not to optimize the power flow distribution along all circuits out of the Bruce Area, but rather to assess whether the proposed plan provides sufficient transmission transfer capability. The observed larger distribution along the Bruce to Milton corridor is acceptable, balances other important factors including cost, flexibility, and land use policy, and is consistent with existing planning practice (i.e., specified distribution of power flow along rights of way is not a reliability or design consideration). In addition, in relation to the alternative options that were considered, the Bruce to Milton line enables the delivery of the targeted generation in the Bruce Area. The results of the assessment performed by the IESO in this regard is depicted in Diagram 14 of the SIA.

(ii) See Response to 1.7(i).

Ontario Energy Board (Board Staff) INTERROGATORY #1.8 List 1

Interrogatory

Issue Number: 1.4
Issue: 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/Sch 1/pp.4 and 5

Preamble:

The Applicant states that the project as defined can meet the requirements of refurbished Bruce A and Bruce B facilities, 725 MW of committed wind and a possible 1,000 MW of future wind for a total of 3,100 MW of additional generating capacity

Questions:

(i) If the 1,000 MW of future wind doesn't materialize, can the project as put forward provide benefits related to increase reliability and security or reduction in transmission system losses? if so please describe these benefits and quantify where possible.

(ii) If providing a response to (i) above in the technical conference is not possible, please indicate would Hydro One be able to prepare such an evaluation and whether it would be available during the round of interrogatories following the technical conference.

(iii) If 3,100 MW of additional capacity does occur as noted above and in addition new nuclear facilities (Bruce C) are also constructed at the Bruce Nuclear Complex, can the transmission project as proposed accommodate this capacity? For the purpose of responding to this hypothetical question please consider first a single unit of 1000 MW capacity, and if workable assume a second unit of 1000 MW capacity, and then a third etc.

(iv) Please repeat the same steps covered in (iii) above with the additional assumption that the interim measures involving installation of 30% Series Compensation is in service as well as the GR scheme, as outlined in Hydro One's evidence.

Response

(i) Hydro One was advised by the IESO that in the event that the planned 1000 MW of wind does not materialize, as assumed by the question, the proposed line would still yield significant reliability benefits. These are described in the System Impact Assessment (Exhibit B, Tab 6, Schedule 2) which was carried out on March 27 2007. Reliability benefits may be summarized as follows(amounts per the SIA):

- facilitating extraction of nuclear generation capacity from the area (i.e., 4 x 750 MW, 4 x 890 MW);
- enabling extraction of approximately 675 MW of committed wind generation;
- reductions in annual transmission losses estimated to be 120 MW;
- reducing the need for using generation rejection in response to a first contingency under outage condition;
- freeing-up transmission capacity to enable connection of about 1000 MW of other generation resources; and,
- providing additional flexibility to manage outages without restricting generation further.

Please also refer to the Updated Evidence dated November 30, 2007 (Exhibit B Tab 6 Schedule 5 Appendix 1) which revises certain forecast estimates to nuclear and wind generation.

(ii) Please refer to Response to 1.8(i).

(iii) The proposed Bruce to Milton project is designed to meet the committed and planned generation additions in the Bruce area. Additional generation in the Bruce Area beyond that outlined in the application, such as the construction of Bruce C units in increments of 1000 MW, would require additional transmission capability beyond the capacity of the proposed new transmission line. At an appropriate time, a planning study would have to be conducted to determine the transmission reinforcement requirements. Such a study has not been conducted to date.

(iv) The applied-for facilities will not prevent incremental transmission capability additions from being provided through use of 30% Series Compensation or other transmission measures. As noted above, an additional planning study would first be required to assess the feasibility of the options identified.

Ontario Energy Board (Board Staff) INTERROGATORY #1.9 List 1

Interrogatory

Issue Number: 1.4
Issue: 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. (a) B/Tab 1/Sch 1/pp. 4 and 5

Ref. (b) B/Tab 6/Sch 2/p. 2/sec 2/paragraph 2

Questions:

(i) Is it feasible to install a transmission line with Quad 932.7 kcmil conductors instead of Quad 585.0 kcmil conductors as outlined in Ref.(b);

(ii) If the assumption in (i) above is feasible, could additional new nuclear generation (assume one unit of 1000 MW) and if workable assume a second units of 1000 MW in addition to the projected 3,300 MW in the Bruce area be accommodated?

(iii) If (ii) indicate that this is a workable option, what would be the estimated cost of a double circuit 500 kV transmission line utilizing this larger conductor arrangement?

Response

(i) Use of Quad 932.7 kcmil would be technically feasible; however, because of conductor weight and span length, tower height and foundation size would increase by approximately 25%. Additional towers would also be required. All of these factors would lead to additional costs as compared to the applied-for Bruce to Milton facilities.

(ii) As indicated in Part (i) above use of Quad 932.7 kcmil would be technically feasible; however, the larger conductor would not increase the transmission capability of the currently applied-for facilities. This is because the reactance of the larger conductor would not be materially different. The only expected benefit arising from use of Quad 932.7 kcmil (as compared to the applied-for facilities) would be reductions in transmission losses of approximately 20 MW per year.

(iii) The cost of conductor and assembly would be expected to increase by approximately 25% with use of Quad 932.7 kcmil. Hydro One is presently investigating the use of Quad 732 kcmil which has recently become more readily available and is not expected to require fundamental changes in design of the line.

Ontario Energy Board (Board Staff) INTERROGATORY #2.1 List 1

Interrogatory

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

Ref B/Tab 3/Sch 1/p. 3

Preamble:

The Applicant states that a transmission line constructed along the existing Bruce to Milton corridor is the only alternative that meets the long term need and satisfies the other key objectives.

Questions/Requests:

(i) Did Hydro One carry out a comparison of the reliability of the proposed line constructed along the Applicant's recommended route compared to a similar double circuit transmission line following routes tracking the B22D/B23D corridor and the D10H corridor? If yes, please provide that comparison. If not provide the reasons for not performing such a comparison.

(ii) If the comparison discussed in (i) above was not carried out, can Hydro One provide such a comparison by October 15 for the technical conference.

Response

(i) No, a comparison of the reliability of the proposed line with the requested route was not performed. This is because the requested route did not pass the initial screening assessment and thus was not considered to be a reasonable option meriting further consideration.

(ii) Please refer to Response 2.1(i).

Ontario Energy Board (Board Staff) INTERROGATORY #2.2 List 1

Interrogatory

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

Ref B/Tab 2/Sch 2/p. 1

Preamble:

The proposed 173 km double circuit transmission line from Bruce Junction to Milton SS is to be located on the north side of the existing ROW corridor from Bruce Junction to Colbeck Junction and on the east side of the existing ROW corridor from Colbeck Junction to Milton SS.

Questions:

Why was this particular orientation selected, as opposed to a location on the south and west sides of the existing ROW corridors?

Response

An explanation of why the proposed transmission line has been sited on the north and east side of the existing transmission corridor was provided during Day 2 of the Technical Conference, held on October 16, 2007. See page 5 line 11 to page 6 line 27 of the Technical Conference transcript.

The north and east sides of the existing corridor were selected for largely technical and economic reasons. The line must exit the Bruce Power Facility on the north side to avoid crossing over the Bruce to Longwood 500 kV line. The proposed line remains on the north and east sides as it runs south, as one of the objectives was to limit the crossings of existing transmission lines. Crossings are technically challenging to build, create system security issues and are costly.

A preliminary review of environmental factors indicated that there were no significant differences between the north and south, or east and west sides. This perspective will be confirmed as part of the environmental assessment (EA) study process. The EA process may bring to light new information that could cause a reconsideration of the route alignment in specific locations of the identified general corridor, however, it is unlikely that a complete switch from north to south or east to west is warranted.

Ontario Energy Board (Board Staff) INTERROGATORY #2.3 List 1

Interrogatory

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

Ref B/Tab 3/Sch 1/pp. 1 to 6

Preamble:
It is important to demonstrate the advantages and disadvantages of the following Alternatives, each selected on an existing ROW corridor and each involving a 500 kV double circuit transmission lines between the Bruce area and the GTA:

(a) the 230 kV Bruce - Detweiler TS double circuit transmission line, B22D and B23D corridor and Kitchener to the GTA via widened existing 230 kV or 500 kV corridors;

(b) the 230 kV Bruce - Owen Sound TS double circuit transmission line, B27S and B28S corridor and Owen Sound to Essa and Essa to the GTA via existing 115 kV and 500 kV corridors; and

(c) the 115 kV Hanover - Detweiler TS single circuit transmission line, D10H corridor and Kitchener to the GTA via widened existing 230 kV or 500 kV corridors.

Requests:

For each of the noted alternative, please provide:

(i) the estimated cost of constructing the 500 kV double circuit transmission lines.

(ii) the advantages and disadvantages of these alternatives in terms of flexibility to operate the transmission system when contingencies occur, flexibility in scheduling maintenance outages, and general requirements.

(iii) The reliability and quality advantages and disadvantages of each alternative.

Response

The alternatives described in these questions were not carried forward for further consideration in the screening process due to their significant disadvantages as compared to the other assessed alternatives. These disadvantages concerned: additional line length; overall cost; relative transmission capability; and, in cases (a) and (c), the need for greenfield corridor for that part of the required route between Detweiler TS and the GTA.

(i) Hydro One has not carried out a detailed estimate of these alternatives for the reasons stated above. Planning quality construction costs incremental to the Bruce to Milton project alternative (based on $3 million per kilometre) are provided below :

   a. B22D/B23 corridor - 70 km incremental; $210M more expensive.

   b. Bruce x Owen Sound x Essa x GTA circuit – 100 km incremental; $300M more expensive.

   c. Bruce x Hanover x Detweiler (D10H) x GTA circuit - 60 km incremental; $180M more expensive.

(ii) An assessment of the advantages and disadvantages of these alternatives in terms of the listed criteria was not carried out for the reasons stated above.

(iii) An assessment of the reliability and quality advantages and disadvantages of these alternatives in terms of the listed criteria was not carried out for the reasons stated above.

Ontario Energy Board (Board Staff) INTERROGATORY #2.4 List 1

Interrogatory

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

Ref B/Tab 3/Sch 1/p. 3

Preamble:
In the Ref. above, the Applicant stated that the proposed solution to the problem of inadequate transmission delivery from the Bruce Complex had to satisfy four key objectives as follows:

- a proposal that is consistent with provincial land use policies for optimizing the use of existing transmission line ROWs;
- a proposal that can be constructed and in-service as soon as possible;
- a proposal that makes use of proven and widely used technology; and
- a proposal that can be constructed with a reasonable cost.

Questions:

(i) How did the OPA arrive at these four objectives and why were they the only objectives that were selected?

(ii) Why were no objectives selected that relate to power system reliability (including security) and quality of electricity service?

(iii) What weightings have the OPA ascribed to each of the four objectives?

Response

(i) In the noted evidence, the OPA stated that various options for reinforcing the transmission system were assessed to ensure that there will be adequate capacity available to transmit all available generation from the Bruce area. The level of generation planned for the Bruce area arises from the Government's policy objectives presented in Exhibit B, Tab 6, Schedule 5, Appendix 1. The OPA used the four objectives referenced in the preamble to this question plus the ability to provide adequate transfer capability and meet the Government's policy objectives as directed, in selecting the proposed project.

The OPA uses a generic process to identify, assess and select plans to meet a defined need:

1. Develop reasonable solutions.

2. Screen options based on a select set of criteria.

3. Evaluate remaining alternatives with a broader set of criteria.

4. Select the preferred plan.

The specific screening criteria cover six areas that are consistent with the key project objectives:

- Government policy

- Reliability related

- Feasibility related

- Flexibility related

- Cost related

- Land use related

After the screening process was conducted, only one option remained, the new line from Bruce to Milton. Therefore, steps 3 and 4 ("Evaluate remaining alternatives with a broader set of criteria" and "Select the preferred plan") were not conducted. The methodology behind the screening of the various alternatives was explained in the Day 1 Technical Conference Presentation (Exhibit KT.1) on slides 26 to 31 and in pages 23 to 29 of the Technical Conference transcript.

(ii) Reliability and quality of electricity service criteria were used in the alternatives screening and evaluation process. Please refer to (i) above.

(iii) The screening process that eliminated all alternatives to the proposed project did not use an objectives-weighting construct. Instead, a "go – no go" decision-making process was used. This is further discussed at page 27 of the Technical Conference transcript.

Ontario Energy Board (Board Staff) INTERROGATORY #2.5 List 1

Interrogatory

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

Ref B/Tab 3/Sch 1/p. 4/lines 9 to 23

Preamble:

(a) In regard to Alternative 1 (500 kV double circuit transmission line from Bruce to Highway 9 Junction to Essa TS), the Applicant states that only 7,300 MW can be delivered over this route.

(b) The applicant also states that another reason that Alternative 1 is undesirable is that it would use approximately 1,000 MW of the available transfer capacity between Essa TS and Claireville TS and this capacity reduction would limit the development of northern generation.

Questions:

(i) What are the limitations to increasing the delivery along this route to the desired 8,100 MW level?

(ii) How can these limitations be mitigated or removed and what is the estimated cost of the mitigation/removal?

(iii) Keeping in mind item (b) in the Preamble and considering that the distance between Essa TS and Claireville TS is only 70 km and space is available on the existing ROW, why was this not considered by the Applicant (or the OPA) in the evidence?

(iv) What would be the estimated cost of constructing a 500 kV double circuit transmission line from Essa TS to Claireville TS?

Response

(i) The limitation to increasing delivery on the Bruce to Essa route is the transmission path from Essa to Claireville which path would need to be reinforced in order to have power delivered to the grid supplying southern Ontario.

(ii) A new 500 kV line along the Essa to Claireville right of way would be required in order to eliminate the limitation and increase the capability of this alternative to 8,100 MW. Based on a double circuit 500 kV line, this would cost approximately $210M (approximately 70 km @ $3M per km).

(iii) The additional cost associated with reinforcing the Essa to Clairville path [Bruce to Essa TS to Claireville TS] would eliminate the option on the basis of cost.

(iv) See part ii.

Ontario Energy Board (Board Staff) INTERROGATORY #2.6 List 1

Interrogatory

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

Ref B/Tab 3/Sch 1/pp. 5 and 6/p.5 (lines 25-58) and p. 6(lines 1-8)

Preamble:

The Applicant states that Alternative 4 would provide less transfer capacity than the preferred option. Alternative 4 is a 500 kV double circuit transmission line from Bruce to Longwood TS and a 500 kV double circuit transmission line from Longwood TS to Middleport TS all along existing ROW corridors.

Questions:

(i) How much transfer capability does the applicant, the IESO and the OPA believe can be provided utilizing this alternative?

(ii) What are the limitations to increasing the transmission delivery with this alternative to the desired 8,100 MW level?

(iii) How can these limitations be mitigated or removed and what is the estimated cost of the mitigation/removal?

(iv) Assuming that the both interim measures (the Generation Rejection and the Series Compensation) are implemented, what would be the total transfer capability of the modified Alternative 4?

Response

(i) The IESO has determined that a system with a new double circuit 500 kV line from Bruce to Longwood and from Longwood to Middleport would have a capability of 6,367 MW.

(ii) The proposed alternative is limited by voltage stability limits.

(iii) The capability of this alternative is significantly lower than the proposed project and would cost approximately twice as much (as it is the same type of line, but is approximately twice as long). No study was conducted to determine exactly how to remove the limitations to this alternative. However, it is believed that adding series compensation to each circuit from Bruce to Longwood and from Longwood to Middleport would provide the required capability. While this option has not been studied, total costs would be expected to be in the range of $225 million.

(iv) Generation rejection is not an appropriate measure to meet long-term increases in transmission capability and for that reason would not be implemented. Please see the response to Board Staff Interrogatory 3.2. While series compensation could increase transfer capability, the precise increase is not known as this option was not studied given the significant costs of this alternative. Please refer to (iii) above.

Ontario Energy Board (Board Staff) INTERROGATORY #2.7 List 1

Interrogatory

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

Ref B/Tab 3/Sch 1/p. 6

Preamble:

(a) The applicant states that Alternative 5 would cost between $1.5 B and $2.0 B. Alternative 5 is a High Voltage Direct Current (HVDC) overhead transmission line from Bruce to Milton.

(b) The conventional HVDC technology would reasonably be used for an application such as this, (noting that HVDC Light technology is only suitable for relatively low power applications), and it is common knowledge that this equipment has been in-service in North America for more than 30 years.

Questions/Requests:

(i) Please provide cost breakdown supporting this cost estimate.

(ii) Did Hydro One carry out an evaluation to quantify the benefits provided by a HVDC line (compared to an equivalent AC line) with respect to improved stability, reliability and controllability and ROW requirements. If yes, please provide such an evaluation. If not provide the rationale for not providing such analysis.

(iii) If the evaluation described in (ii) above was not carried out, can Hydro One provide such an evaluation by October 15 for the technical conference.

(iv) Given the status of the technology in Preamble (b) please provide the rationale for Applicant's statement that "there are technology risks associated with this alternative".

Response

(i) Two HVDC lines would be required to provide 3000 MW of additional transfer capability, equivalent to the amount provided by the proposed project. The cost of a HVDC line is typically 80% of an HVac line. Using the cost of Bruce x Milton line cost and applying the 80% multiplier, the cost of a HVDC line can be estimated as $450 million per line. In addition, HVDC converters are required one at Bruce and another at Milton each with capacity of 3000 MW. Typical cost of a HVDC converter is about $150/ kW.

In summary:

$450 M x 2 for HVDC lines: $900 M
$150 x 3000 x 2 for converters: $900 M
Total cost of approximately $1.8 B.

(ii) An evaluation to quantify the benefits was not carried out as the HVDC alternatives were rejected due to their significantly higher cost relative to the applied-for line and given comparable levels of capability. Please also refer to the Technical Conference transcript (see pages 27 to 29).

(iii) Please refer to (ii).

(iv) At this time, the largest installation of the HVDC "lite" technology is, to OPA's knowledge, approximately 500 MW. A 1,000 MW application of this technology is under development. However, no 1,000 MW application has been installed as of yet. At this time, this technology is not considered technologically mature to fulfill the need of this project in a reliable manner. This was discussed at the Technical Conference (see page 28, 158 and 159 of the Technical Conference Transcript).

Ontario Energy Board (Board Staff) INTERROGATORY #2.8 List 1

Interrogatory

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

Ref B/Tab 3/Sch 1/pp. 5 and 6
IESO System Impact Assessment Report CAA ID No. 2005-200

Preamble:

An alternative involving a 500 kV single circuit transmission line from Longwood TS to Nanticoke GS or Middleport TS along an existing ROW corridor may be viewed as a workable alternative. For example if the M31W – M32W – M33W corridor could be used and if one of the existing 230 kV lines could be removed, a new 500 kV line could likely be installed without the requirement to acquire any additional property.

Questions/ Requests:

(i) Did Hydro One carry out such an evaluation? If yes, please provide it.

(ii) If the answer to (i) above is negative, please provide the following assuming that a line such as noted above could be constructed:

a. How much transfer capability does the Applicant believe can be provided by an alternative such as this?

b. What are the limitations to increasing the delivery utilizing this alternative to the desired 8,100 MW level?

c. How can these limitations be mitigated or removed and what is the estimated cost of the mitigation/removal?

d. Assuming that the both interim measures are implemented, what would be the total transfer capability of the modification to this Alternative?

Response

(i) and (ii) For the following reasons, Hydro One and OPA do not consider a 500 kV single circuit transmission line from Longwood TS to Nanticoke GS or Middleport TS along an existing ROW corridor to be a workable alternative:

- The option would be limited by thermal, voltage stability and transient stability limitations.

- An additional line from Bruce to Longwood as well as series capacitors on each of the 500 kV circuits from Bruce to Longwood, Longwood to Nanticoke and Longwood to Middleport would be required. These additions would make it similar to the alternative discussed in Board Staff Interrogatory 2.6.

- Using generation rejection for increasing transmission capability is not appropriate to meet long-term increases in transfer capability requirements. Please refer to the response to Board Staff Interrogatory 3.2.

- While series capacitors could increase transfer capability, the amount is limited by the thermal capability. The need identified in these circumstances exceeds the thermal capability of this option. As a result, this option is not considered to be a reasonable alternative.

Ontario Energy Board (Board Staff) INTERROGATORY #2.9 List 1

Interrogatory

Issue Number: 2.3
Issue: For all of the considered alternatives, does the evaluation methodology utilized include a cost benefit comparison as well as a comparison of all quantitative and qualitative benefits?

Ref B/Tab 3/Sch 1/pp. 3 to 6

Preamble:

Page 3, lines 14 to 16, of the above noted reference states that "The OPA concluded that the only alternative that meets the long-term need and satisfies the other key objectives is a new double-circuit 500 kV line from Bruce to Milton within a widened existing Bruce to Milton corridor". Pages 4-6 describe four other alternatives that were considered and rejected. It is further stated that: the "Bruce to Essa TS" alternative was rejected for failing to meet the needed transfer capability; the "Bruce to Kleinburg TS" was rejected because over 52 km of new transmission corridor is required; and, the "Bruce to Guelph area" alternative was rejected because at least 30 km of new transmission corridor is required.

Questions/Requests:

(i) Has the OPA or Hydro One carried out any comparative cost benefit analysis of the alternatives considered covering all quantitative and qualitative benefits? If so, please provide the results. If not please provide the reasons for not carrying out such an evaluation.

(ii) If the response to (i) above is negative, please indicate if such evaluations on the 5 alternatives can be carried out and the results presented in the evidence, if possible at the technical conference, to allow for meaningful comparison.

(iii) Please indicate whether Hydro One carried out loss of load probability evaluation on all five Alternatives? If so please provide such evaluation. \

(iv) If the answer to (iii) above is negative, please indicate whether Hydro One can carry out loss of load probability evaluation on all five Alternatives, and provide the results either at the technical conference or in response to an interrogatory during the round of interrogatories phase of this proceeding. In carrying such a study, please consider evaluating an average financial impact on transmission customers expressed in dollars(also commonly known as customer damage cost) of each Alternative using typical values per customer from older studies that Ontario Hydro had completed and would be adjusted for inflation. If such studies are not available to Hydro One, please use other industry sources from the electricity industry in U.S.A.

(v) Is it normal practice to rule out alternatives that require new transmission corridor when an existing corridor is available? If so:

- please provide details of Ontario's land use policy that would require this;

- and, if not:

- Please explain further why the "Bruce to Kleinburg TS" and the "Bruce to Guelph area" alternatives were discarded.

Response

(i) A study to determine exactly all the costs and benefits associated with each alternative was not conducted since all alternatives, other than the proposed Bruce to Milton line, were screened out. Please refer to response to Board Staff Interrogatory 2.4 for a discussion of the screening process that was used for the Bruce to Milton project.

(ii) The result of the screening process was that only one alternative was determined to meet the identified need. Had multiple alternatives passed the screening process, then a detailed cost-benefit analysis comparing alternatives would have been carried out. Please refer to response to Board Staff Interrogatory 2.4 for a discussion of the screening process.

(iii) A loss of load probability evaluation of these alternatives was not conducted for the reasons indicated in (i) and (ii).

(iv) Alternatives were not assessed based on loss of load probability evaluation. Instead, deterministic criteria were used to test and design bulk transmission systems and evaluate the ability to deliver targeted generation to the power grid. Use of deterministic criteria for transmission planning purposes is consistent with the criteria and practices of the NPCC (i.e. Standard A-2 Basic Criteria for Design and Operation of Interconnected Power Systems) and the IESO (i.e. Ontario Resource and Transmission Assessment Criteria).

For the most part, loss of load probability evaluation is normally used for resource adequacy assessments in bulk system planning. Since the proposed line provides sufficient capability to meet the identified generation need, a loss of load probability evaluation was not necessary. A discussion of planning methodology and criteria was presented at Day 1 of the Technical Conference (see Day 1 Technical Conference Presentation Exhibit KT.1 slides 8 to 11, and pages 11 to 14 of the transcript).

(v) Where existing corridor space is available, Hydro One's policy is to use such available space. However, in the present circumstances there is no such available corridor space. Accordingly, before proposing new, "greenfield" developments, the OPA considered how to optimize and make best use of existing infrastructure in accordance with the 2005 Provincial Policy Statement (PPS). This resulted in the selection of the Bruce to Milton route. The Provincial Policy Statement (PPS) can be found in Exhibit B, Schedule 6, Tab 5, Appendix 13. On page 10 it notably provides:

- *1.6.2 The use of existing infrastructure and public service facilities should be optimized, wherever feasible, before consideration is given to developing new infrastructure and public service facilities.*

- *Infrastructure is defined to include "electric power generation and transmission" on page 32 of the PPS.*

The PPS is also consistent with past longstanding and mandated Ontario Hydro policy to make best use of existing corridors before seeking approval for new corridors. For example, the 1975 Royal Commission on Electric Power Planning recommended that "upgrading existing transmission facilities" and "optimizing the use of existing rights of way" ought to be a "continuing programme." The direction to take into account Provincial land use policies was iterated in the July 1988 Report to the Minister of Energy, specifically that "wherever it is feasible to upgrade existing transmission lines or corridors, this option should be evaluated before seeking approvals for new corridors."

Advantages that accrue from making use of existing rights of way, and underlie the choice of the Bruce to Milton 500 kV option, are:

- The required widening of Bruce to Milton corridor portion is about 20% less than the creation of a greenfield corridor and allows for a smaller overall footprint with less impact on land use, property owners, the natural and socio-economic environment;

- Selecting an appropriate location for a greenfield corridor in Southwest Ontario is difficult in view of increasing density and the need to preserve existing rural areas to minimize disruption to families and businesses; and

- The selection of a greenfield corridor is a time-consuming process and incompatible with the identified need for the Bruce to Milton Project.

Ontario Energy Board (Board Staff) INTERROGATORY #2.10 List 1

Interrogatory

Issue Number: 2.3
Issue: For all of the considered alternatives, does the evaluation methodology utilized include a cost benefit comparison as well as a comparison of all quantitative and qualitative benefits?

Ref (a) B/Tab 6/Sch 2

Ref(b) Filing Requirements for Transmission and Distribution Applications (November 14, 2006)/p. 35/section 5.3.2/3rd paragraph

Preamble:

(a) In Ref.(a), second paragraph on page 1, it is stated that "Under the OEB Act, 1998, s. 96 (2), "public interest" is defined to mean the interests of consumers with respect to prices and the reliability and quality of electricity service".

(b) In Ref.(b), it is stated that: "One way for an Applicant to demonstrate that that a preferred option is the best option is to show that it has the highest net present value as compared to the other viable alternatives. However, this net present value need not be shown to be greater than zero. In the case of an internally set project, "doing nothing" would count as a viable option."

Questions/Requests:

(i) Given the Preambles (a) and (b), has the OPA or Hydro One carried out a comparative analysis of the alternatives considered in terms of prices, reliability and quality of electrical service? If not why not? If so, please provide a summary of the results.

(ii) Has the OPA or Hydro One considered the reliability impact of adding transmission to an existing corridor vs. a new corridor or a corridor where multiple line outages would less impactive? If not why not? If so, please provide results of any analysis that was done.

Response

(i) Price, reliability and quality of electricity service were attributes that the OPA and Hydro One took into consideration in the development, the screening and the evaluation of all reasonable alternatives identified. The price of electricity to consumers is factored into the assessment of each alternative by examining: (a) the overall estimated project costs using parameters such as length of the lines and the per kilometer cost of installing a line, (b) operational efficiency as related to transmission losses, and (c) the relative capability of the alternatives to minimize or eliminate congestion and undelivered energy. Discussion of these matters were presented during Day 1 of the Technical Conference (see: Day 1 Technical Conference Presentation, Exhibit KT.1 slides 27 to 31 and pages 23 to 29 of the transcript).

Reliability and quality of electrical service were also essential criteria that OPA and Hydro One considered during the evaluation of the identified alternatives. Based on the analysis conducted, none of the alternatives other than the applied-for Bruce to Milton option has the transfer capability necessary to satisfy the identified need as well as achieve a standard of quality and reliability of electrical service superior to the Bruce to Milton option. Alternatives were considered for their technical feasibility (e.g. HVDC "Lite" technology), impact on overall system operation (e.g., the Bruce to Essa alternative with respect to the Essa to Claireville path) and overall system robustness (e.g., a new transmission line as compared to the use of series compensation of the existing transmission system). These matters related to reliability and quality of electrical service were presented and discussed throughout the course of the Technical Conference (see: Day 1 Technical Conference Presentation, Exhibit KT.1).

(ii) Yes, the potential reliability impact of adding the new transmission line to an existing corridor has been considered. The results of the SIA confirmed that the proposed Bruce to Milton line satisfies reliability standards and will not adversely impact the IESO-controlled grid. All else being equal, siting transmission lines on separate corridors is better than using common rights-of-way. However, the IESO believes the risk of a loss of right-of-way contingency is acceptable and manageable, and is consistent with existing design and planning practice in Ontario (i.e., multiple-double circuit 500 kV lines on the same rights of way). In addition it is noted:

- extreme weather events, such as ice storms can cover a wide area, with the result that having separate rights of way is unlikely to mitigate the risk of outages to multiple facilities;

- the IESO has policies and procedures that are employed when there is advanced warning of extreme events such as tornados and ice storms - measures include redispatching power, switching transmission facilities to contain adverse impacts, and the use of SPS;

- Ontario currently has a number of multiple-double circuit 500 kV lines on the same rights of way; and

- NPCC reliability planning criteria do not preclude the use of multiple lines on a common right of way.

Please also refer to the Day 1 Technical Conference Presentation Exhibit KT.1 slide 34 and transcript pages 30-31.

Ontario Energy Board (Board Staff) INTERROGATORY #2.11 List 1

Interrogatory

Issue Number: 2.4 a
Issue: 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?

Ref B/Tab 6/Sch 2 (IESO System Impact Assessment Report)/Sec. 8/p. 9 and Diagram 5

Preamble:

(a) The IESO states that with the proposed 500 kV double circuit Bruce to Milton line in service, the existing 500 kV line, M585M, from Middleport TS to Milton SS is projected to carry out virtually no power delivery (load flow of 5.1 MW) under normal conditions.

(b) The IESO further explains that the proposed 500 kV double circuit line provides valuable voltage support by delivering reactive power to Milton SS. In the IESO's SIA report, Diagram 5 indicates that with all transmission circuits in service and the system loaded at 28,400 MW, the reactive power delivered by the M585M transmission line is projected to be 219.5 MVARs.

Questions:

(i) In regard to Preamble (a), and since practically no power delivery is projected for this scenario, does the Applicant and the IESO believe that the other benefits provided justify the transmission line arrangement and location as proposed? and if so, please provide detailed description of these other benefits and quantification of these benefits where feasible.

(ii) In regard to Preamble (b), what would be the estimated cost of a shunt capacitor installation at Milton SS that could provide an equivalent amount of reactive power (i.e. 220 MVARs)

Response

(i) Yes, the arrangement and location of the proposed line yield the best set of benefits and outcomes when compared to all other reasonable alternatives. Consequently, the IESO has advised Hydro One that it concurs with Hydro One regarding the design, configuration and location of the new line.

The reduced load flow observed along the Middleport to Milton corridor is due largely to the planned cessation of generation at Nanticoke GS. And is largely unrelated to the proposed Bruce to Milton facilities.

(i) The estimated cost of installing a 220 MVAr capacitor bank installation at Milton SS is approximately $10-15 million.

Ontario Energy Board (Board Staff) INTERROGATORY #2.12 List 1

Interrogatory

Issue Number: 2.6
Issue: Are the project's rate impacts and costs reasonable for:

- the transmission line;
- the station modifications; and
- the estimated Operating, Maintenance and Administration requirements.

Ref B/Tab 4/Sch 2/p. 1/Table 1

Preamble:

The foot note for Table 1 indicate that carrying costs are included in the cost estimates

Questions/Requests:

(i) Please clarify whether the carrying costs referred to in Table 1 are the AFUDC amounts that are shown in Table 2 (page 2) and in Table 4 (page 3)?

(ii) If the carrying costs are not those reflected in the AFUDC amounts, please provide a Table (replacing Table 1) depicting the three categories of cost estimates without the carrying cost, and identify for each on separate line the corresponding carrying costs for each.

(iii) In reference to (ii) above, please provide adequate detailed explanation of how the carrying costs were calculated.

Response

(i) Yes, the carrying costs referred to in Table 1 are the AFUDC amounts in Table 2 and Table 4.

(ii) Not applicable

(iii) Not applicable

Ontario Energy Board (Board Staff) INTERROGATORY #2.13 List 1

Interrogatory

Issue Number: 2.6
Issue: Are the project's rate impacts and costs reasonable for:

- the transmission line;
- the station modifications; and
- the estimated Operating, Maintenance and Administration requirements.

Ref B/Tab 4/Sch 2/p. 1/Tables 2 and 3

Questions/Requests:

(i) Please provide for each of the two tables the costs broken down by each of the Stations (Bruce A, Bruce B, Milton SS);

(ii) Please provide the basis for the overheads amounts, and provide a break down of each of the two overhead amounts into direct overhead (field supervision…etc) and indirect overhead (cover head office functions …etc.).

Response

(i)

Table 2 - Cost of Station Work

	Total	Milton	Bruce A	Bruce B
Material	33,300	22,200	5,000	6,100
Construction	11,200	3,000	3,600	4,600
Engineering & PM	4,900	1,800	1,500	1,600
Commissioning	1,800	900	400	500
Contingencies	5,000	2,500	1,200	1,300
Costs before OH and AFUDC	56,200	30,400	11,700	14,100
OH	6,700	3,600	1,400	1,700
AFUDC	5,100	2,800	1,100	1,200
Total Station Cost	68,000	36,800	14,200	17,000

Table 3 - Cost of Station Work

	Total	Milton	Bruce A	Bruce B
Breakers, switches	39,000	28,000	5,000	6,000
P & C and Telecom.	8,000	4,000	2,000	2,000
Other	15,000	1,800	5,800	7,400
Contingency	6,000	3,000	1,400	1,600
Total Station Cost	68,000	36,800	14,200	17,000

(ii) The overhead amounts are based on the standard forecast Hydro One Transmission capitalized overhead rates, per the company's business plan, for the years in which the costs are expected to be incurred. See Exhibit B, Tab 4, Schedule 4, p. 5 (Nov. 30th update) for the capitalized overhead rates.

All of the overhead amounts are indirect overheads. Direct overheads are included in the wage rates and charged as direct labour costs to the project.

Ontario Energy Board (Board Staff) INTERROGATORY #2.14 List 1

Interrogatory

Issue Number: 2.6
Issue: Are the project's rate impacts and costs reasonable for:

- the transmission line;
- the station modifications; and
- the estimated Operating, Maintenance and Administration requirements.

Ref B/Tab 4/Sch 2/p. 3/Table 4

Questions/Requests:

Please provide the basis for the overheads amounts, and provide a break down of that overhead into direct overhead (field supervision…etc) and indirect overhead (cover head office functions …etc.).

Response

Please see the response to Board Staff Interrogatory 2.13 (ii).

Ontario Energy Board (Board Staff) INTERROGATORY #2.15 List 1

Interrogatory

Issue Number: 2.6
Issue: Are the project's rate impacts and costs reasonable for:

- the transmission line;
- the station modifications; and
- the estimated Operating, Maintenance and Administration requirements.

Ref B/Tab 4/Sch 2/pp. 4 and 5/Table 5

Preamble:

(a) The evidence regarding Cost of Comparable Projects is shown in Table 5, featuring comparable projects constructed in the early to mid 1990's.

(b) There is a need to compare the projects on constant dollar value basis and per kilometre basis.

Questions/Requests:

In order to compare the projects on constant dollar value basis and per kilometre basis, please carry out the following steps and provide the answer in a tabular form:

(i) use the in-service date of 1990-07-01 for the "Bruce x Longwood" project as a reference point and adjust the costs of the three other projects down by the appropriate blended deflation rate.

(ii) The blended deflation rate would have two parts (one for Labour and the other for Material) and weighed by the Portion of each of the two Cost Components.

(iii) Use the corresponding Length in kilometres to produce a $/km for each of the four projects. Please list all the assumptions and show details of the calculations.

(iv) Please carry out the same steps to arrive at a cost in $/km (1990) of the original project [the Bruce x Milton 500 kV double circuit transmission line], which was in-service at the time the Bruce Complex was commissioned. In this case inflation rates would be used in similar manner to achieve this step.

Response

(i) –(iv) Comparable project costs on a constant-dollar ($1990), unit-cost-per-kilometer basis are provided in the table below, along with supporting information in succeeding tables. Please note that largely due to recent price increases in key materials used in transmission line construction such as steel used in transmission towers and in copper used as conductor, Material costs of the applied-for Bruce to Milton project comprise a greater percentage of costs than for the comparable projects. The impact of these Materials price increases on the Bruce to Milton project is not fully reflected in the Statistics Canada Materials price index used to determine the Bruce to Milton project's constant-dollar costs, due to the index's breadth. The broader array of materials in the index moderates the impact of price increases in transmission-specific items. This tends to understate the cost deflator used to determine the Bruce to Milton project's constant dollar costs and overstate its constant-dollar costs, relative to the other projects.

Bruce to Milton
Comparable Projects
Unit Line Cost, Constant Dollar Basis
1990 = 1.00

Line	Project	col. 1 Bruce x Milton TS	col. 2 Cherrywood TS x Claireville TS	col. 3 Lennox TS x Bowmanville TS	col. 4 Bruce x Longwood TS	col. 5 Bruce x Milton Original Line
		(estimated)	(actual)	(actual)	(actual)	(actual)
		2 x 500 kV	2 x 500 kV	2 x 500 kV	2 x 500 kV	2 x 500 kV
		V1 type towers	V1 type towers	V1 type towers	V1 type towers	V1 type towers
	Conductor Type	585 kcmil	585 kcmil	585 kcmil	585 kcmil	585 kcmil
A	**Length (km)**	179	46	178	186	176
	In-Service Date	9/30/2011	2/26/1993	11/1/1994	7/1/1990	7/2/1990
B	**Total Line Cost * - $ of the in-service year**	$420,000,000	$81,400,000	$202,000,000	$218,000,000	$71,000,000
	of which, Labour	$92,000	$27,900,000	$91,500,000	$86,100,000	$27,500,000
	Material	$218,000	$22,000,000	$63,700,000	$79,500,000	$32,000,000
	Total Labour and Material **	$310,000	$49,900,000	$155,200,000	$165,600,000	$59,500,000
	Labour %	30%	56%	59%	52%	46%
	Material %	70%	44%	41%	48%	54%
C	**Blended Labour/Material Deflator from in-service date to 1990, per cost index**	1.52	1.01	1.06	1.00	0.62
D=B/C	**Deflated Total Cost ($1990) *****	$277,100,000	$80,700,000	$191,300,000	$218,000,000	$114,800,000
E=D/A	**Deflated Total Cost per km ($1990) *****	$1,500,000	$1,800,000	$1,100,000	$1,200,000	$700,000

** Does not include station work or property costs*
*** Labour and Material cost split based on Total Costs excluding property, overheads, interest and contingencies.*
**** Rounded to nearest $100k.*

Cost of Comparable Projects
Derivation of Blended Labour/Material Deflator
From 1990 to in-service year
1990 = 1.00

		col. 1	col. 2	col. 3	col. 4	col. 5	col. 6	col. 7	col. 8	col. 9	col. 10
Line	**Item**	**Bruce x Milton TS**		**Cherrywood TS x Claireville TS**		**Lennox TS x Bowmanville TS**		**Bruce x Longwood TS**		**Bruce x Milton Original Line**	
A	**In-service date**	9/30/2011		2/26/1993		11/1/1994		7/1/1990		1980-07-03	
		Material	Labour	Material	Labour	Material	Labour	Material	Labour	Material	Labour
B	**Cost Deflator, 1990 to in-service year ***	1.51	1.53	0.88	1.11	0.95	1.13	1.00	1.00	0.66	0.57
C	**Labour/Material cost split**	70%	30%	44%	56%	41%	59%	48%	52%	54%	46%
D=B*C	**Weighted Cost Deflator**	1.06	0.45	0.39	0.62	0.39	0.67	0.48	0.52	0.35	0.26
E=Line D, col (i)+(i+1)	**Blended Deflator, Labour and Material**		1.52		1.01		1.06		1.00		0.62

** Deflator calculated to the year of in-service. Deflator per Cost Index.*

Transmission Labour and Material Cost Index				
	(1980 = 1.00)		(1990 = 1.00)	
Year	Material	Labour	Material	Labour
2012	2.35	2.74	1.55	1.57
2011	2.28	2.67	1.51	1.53
2010	2.23	2.60	1.48	1.49
2009	2.19	2.54	1.45	1.45
2008	2.16	2.46	1.43	1.41
2007	2.12	2.41	1.40	1.38
2006	2.02	2.38	1.33	1.37
2005	1.89	2.33	1.25	1.33
2004	1.85	2.28	1.23	1.31
2003	1.68	2.25	1.11	1.29
2002	1.69	2.20	1.12	1.26
2001	1.66	2.14	1.10	1.23
2000	1.67	2.11	1.11	1.21
1999	1.64	2.07	1.08	1.19
1998	1.68	2.05	1.11	1.17
1997	1.66	2.03	1.10	1.16
1996	1.63	2.00	1.08	1.15
1995	1.59	1.99	1.05	1.14
1994	1.44	1.97	0.95	1.13
1993	1.33	1.94	0.88	1.11
1992	1.28	1.90	0.85	1.09
1991	1.36	1.83	0.90	1.05
1990	1.51	1.75	1.00	1.00
1989	1.51	1.65	1.00	0.94
1988	1.45	1.55	0.96	0.89
1987	1.25	1.49	0.83	0.85
1986	1.19	1.44	0.78	0.83
1985	1.14	1.41	0.76	0.81
1984	1.16	1.38	0.77	0.79
1983	1.10	1.33	0.73	0.76
1982	1.08	1.19	0.72	0.68
1981	1.08	1.09	0.72	0.62
1980	1.00	1.00	0.66	0.57

Source: History (1980 to 2007) is from Statistics Canada. Forecast for labour is from Conference Board of Canada, and for material is imputed from Global Insight Power Planner.

Ontario Energy Board (Board Staff) INTERROGATORY #3.1 List 1

Interrogatory

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

Ref (a) B/Tab 1/Sch 3/p. 1/section 2.0 “Need for the Project”

Ref (b) Hydro One’s response to Board Staff interrogatory No. 84 [Exh J/T 1/S 84] - the “2007 and 2008 Electricity Transmission Revenue Requirements Hearing” (EB-2006-0501) – the interrogatory response included a copy of the Repor titled “Series Capacitor Application in Ontario:SSR Mitigation Final Report; Electric Systems Consulting, ABB Inc., Raleigh, NC, March 30, 2006”.

Ref (c) B/Tab 6/Sch 5/Appendix 2(letter dated December 22, 2006 from OPA)/p. 3/last paragraph

Ref (d) B/Tab 6/Sch 5/Appendix 5/ OPA’s Transmission Discussion Paper No. 5/pp. 50 to 53

Preamble:

(a) In Ref. (a) the applicant identifies its reliance on the OPA Materials for justification of Need and indicate the location of that material in the evidence to be in Exh. B/T 6/S 5.

(b) In Reference (b), ABB state in the Conclusions and Recommendations on page 50 that…the problem of SSR is manageable and can be mitigated for all units with a combination of operating strategies and the application of Thyrister Controlled Series Capacitors (TCSC)

(c) In Ref.(c), OPA stated in part that
“With regard to series compensation, a new technology for Ontario, for increasing transmission capacity out of Bruce, Hydro One Networks has expressed concern regarding the system and equipment risks”. The OPA appreciates this concern and will retain **third party experts to undertake due diligence study to assess the suitability and risks associated with the use of series compensation for this application.** Staff of Hydro One Networks and the OPA have drafted a document that addresses the scope of technical issues and concerns to be covered by this study. The process to retain an appropriate consultant has commenced.”

(d) Board staff consider the completion of the study outlined in Preamble (c) above and its submission to the Board prior to the Oral Hearing on January 14, 2008 to be essential and key to understanding the full picture of the project and its impact on consumers with respect to prices and the reliability and quality of electricity service.

(e) The interim measures mentioned in Ref.(d) including installation of series compensation are considered critical elements for the period between 2009 and 2011 of integrating the additional generation resources in the Bruce area.

Requests:

(i) Please provide the document drafted by Hydro One and the OPA for the noted study;

(ii) Please provide the time-line for completing the study.

(iii) As highlighted in Preamble (c) and (d) above, please provide the latest draft of the study.

(iv) Please indicate when the completed study referred to in Preambles (c) and (d) above would be submitted to the Board?

(v) Given that ABB has already complete its report and indicated that TCSC are feasible for the application in question why hasn't this been factored into the plans of the Applicant.

Response

(i) Please see the response to Pappas Interrogatory No.9.

(ii) The study has been completed.

(iii) Please see the response to Pappas Interrogatory No.6.

(iv) Please see the response to Pappas Interrogatory No.6.

(v) ABB's conclusion as related to the use of Thyristor Controlled Series Capacitors (TCSC) to mitigate the risk of subsynchronous resonance was for a series compensation level of 70%. That was the level thought to be required by Hydro One in order to increase the transfer capability of the existing Bruce transmission system at the time of retaining ABB to conduct the study.

Since that time, the IESO has determined that a 30% compensation level is more appropriate. At the 30% level, Hydro One, OPA and IESO believe that the TCSC technology will not likely be required in order to minimize sub-synchronous resonance on the Bruce transmission system. As presented at the Technical Conference (see: Day 1 Technical Conference Presentation Exhibit KT.1 slide 31 and discussed at pages 27 and 28 of the transcript), series compensation is an interim measure that could be employed as a stop-gap measure if the proposed Bruce to Milton 500 kV line is significantly delayed. However, series compensation, by itself, is not an alternative to the proposed facilities as it does not provide a sufficient increase to the transfer capability for the Bruce transmission system to meet the need identified.

Ontario Energy Board (Board Staff) INTERROGATORY #3.2 List 1

Interrogatory

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

Ref B/Tab 6/Sch 5/Appendix 2(letter dated December 22, 2006 from OPA)/pp. 2 to 5

Preamble:

The letter states that the proposed interim measures (generation rejection and series compensation) are not suitable long term solutions and they increase the risk to the security and reliability of the power system.

Questions:

(i) If the Applicant and the OPA believe that measures such as this can negatively impact the security and reliability of the power system why are they being considered and proposed as interim measures?

(ii) What does the Applicant, the IESO and the OPA believe are the specific technical and operational reasons that limit the use of these interim measures and what actions can be taken to limit their impact to system security and reliability?

Response

(i) and (ii) Generation rejection and series compensation are being considered as interim measures until additional transmission is built, and only to the extent that they can be used in the interim period to cost-effectively increase the transmission transfer capability and to reduce bottled energy and congestion costs, at a level of risk consistent with industry practices and applicable NPCC design criteria.

Generation rejection and series compensation are both considered only as interim measures because they provide insufficient transmission transfer capability to reliably deliver the forecast amount of generation to the grid (i.e., the need), and both, when employed, introduce an increased level of reliability risk to the operation of the bulk power system.

With respect to generation rejection, a type of Special Protection System, or SPS, NPCC design criteria state that "A special protection system (SPS) shall be used judiciously and when employed, shall be installed, consistent with good system design and operating policy. A SPS may be used to provide protection for infrequent contingencies, or for temporary conditions that may exist such as project delays, unusual combinations of system demand and equipment outages or availability, or specific equipment maintenance outages. An SPS may also be applied to preserve system integrity in the event of severe facility outages and extreme contingencies. The decision to employ an SPS shall take into account the complexity of the scheme and the consequences of correct or incorrect operation as well as its benefits." [Ref: NPCC A-2: http://www.npcc.org/viewDoc.aspx?name=A-02.pdf&cat=regStandCriteria]

Accordingly, in assessing transmission plans and their effect on the reliability of the bulk power system, the IESO permits the use of Special Protection Systems, with all transmission elements in service, only for transition periods while new transmission reinforcements are being brought into service.

"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." [Ref: IESO Resource and Transmission Assessment Criteria: http://www.ieso.ca/imoweb/pubs/marketAdmin/IMO_REQ_0041_TransmissionAssessmentCriteria.pdf]

The use of generation rejection brings additional risks to the reliability of the bulk power system, as it relies on the use of complex electronic control equipment and circuit breakers to operate correctly, automatically, and at very high speed to manage and control the integrity of the power system immediately following a system contingency. This risk is weighed against the economic benefits of permitting higher transfer capability, and thereby lower congestion costs, and is considered an acceptable part of a long-term plan only during temporary conditions that may exist such as project delays, unusual combinations of system demand and equipment outages or availability, or specific equipment maintenance outages.

With respect to series compensation, the option under consideration provides insufficient transmission transfer capability to reliably deliver the forecast amount of generation to the grid (i.e., the need). Series compensation does not add new transmission circuits to the grid. It comprises a set of equipment, that when connected to existing transmission circuits, alters their electrical characteristics so they behave like shorter lines, and so can be operated at a higher transfer capability. Operating the existing transmission circuits at higher transfer levels results in an increased risk, as there is less margin for contingencies, and little or no margin for prolonged forced or planned equipment outages, especially if they involve the series compensated circuits.

Use of series compensation on circuits connected close to large turbine-generators also exposes the units to the risk of damaging mechanical stresses known as sub-synchronous resonance. This is well known to the industry but new to Ontario. This can introduce increased cost and complexity to control and must be managed to the satisfaction of the generation owners.

Operating the system at a higher transfer level without the Bruce to Milton line:

(i) will result in less margin for contingencies,

(ii) will make it exceedingly difficult to schedule maintenance outages to transmission,

(iii) is expected to require more frequent curtailment of nuclear and wind sourced generation that is not easily dispatched,

(iv) will increase the amount of operating reserve during outage conditions,

(v) will require greater and more complex re-dispatch actions to "re-prepare" the system following contingencies,

(vi) will result in increased power losses,

(vii) will require complex real time control of reactive power and voltage regulation for south-western Ontario that, for various contingencies, may simultaneously expose the system to excessively high and low voltages,

(viii) will require increased reliance on the use of generation rejection and its associated risk of a failure of the special protection system to operate when required.

Ontario Energy Board (Board Staff) INTERROGATORY #3.3 List 1

Interrogatory

Issue Number: 3.2
Issue: Can the proposed near term and interim measures be utilized longer than the suggested two to three year time frame?

Ref (a) B/Tab 6/Sch 2/Sec. 8.2 (pp. 10 and 11) & Sec.9.1.1 (p. 12)

Ref (b) Hydro One's response to Board Staff interrogatory No. 84 [Exh J/T 1/S 84] - the "2007 and 2008 Electricity Transmission Revenue Requirements Hearing" (EB-2006-0501).

Preamble:

It is essential and informative to have the IESO perform additional analysis to show the effect of the scenario where the Series Compensation is assumed in-service by 2009, on the system prior to and after the installation of the proposed new transmission lines.

Requests:

With the assumption that the Series Compensation installation is in service by 2009 with sizes and location per the IESO suggestion i.e., 30 % compensation level [see Ref. (b)], please carryout a repeat of five system simulations that will show the load flows under normal and contingency conditions as described in the above Ref.(a), and whose results were depicted in Diagrams 4, 5, 6, 7 and 13 of that Ref.(a).

Response

Under the Bruce to Milton option, the 500 kV bus-bar at Milton SS must be reconfigured. Under the series compensation scenario, the Milton 500 kV bus-bar would not require reconfiguration. Consequently, three of the five contingency conditions that were examined in the Bruce to Milton SIA Report and referenced above—involving the new 500 kV circuits and specifically the reconfiguration of the 500 kV bus-bar—would not be applicable.

The IESO has therefore examined the two remaining applicable contingences that do not involve reconfiguration of the Milton SS 500 kV bus-bar for breaker failure conditions involving the following circuits:

i) Breaker L61L71: affecting circuits B561M & M571V

ii) Breaker L70L73: affecting circuits M570V & M573T

These results are shown in Attachment 1 and 2

Filed: March 10, 2008
EB-2007-0050
Exhibit C
Tab 1
Schedule 3.3
Attachment 1

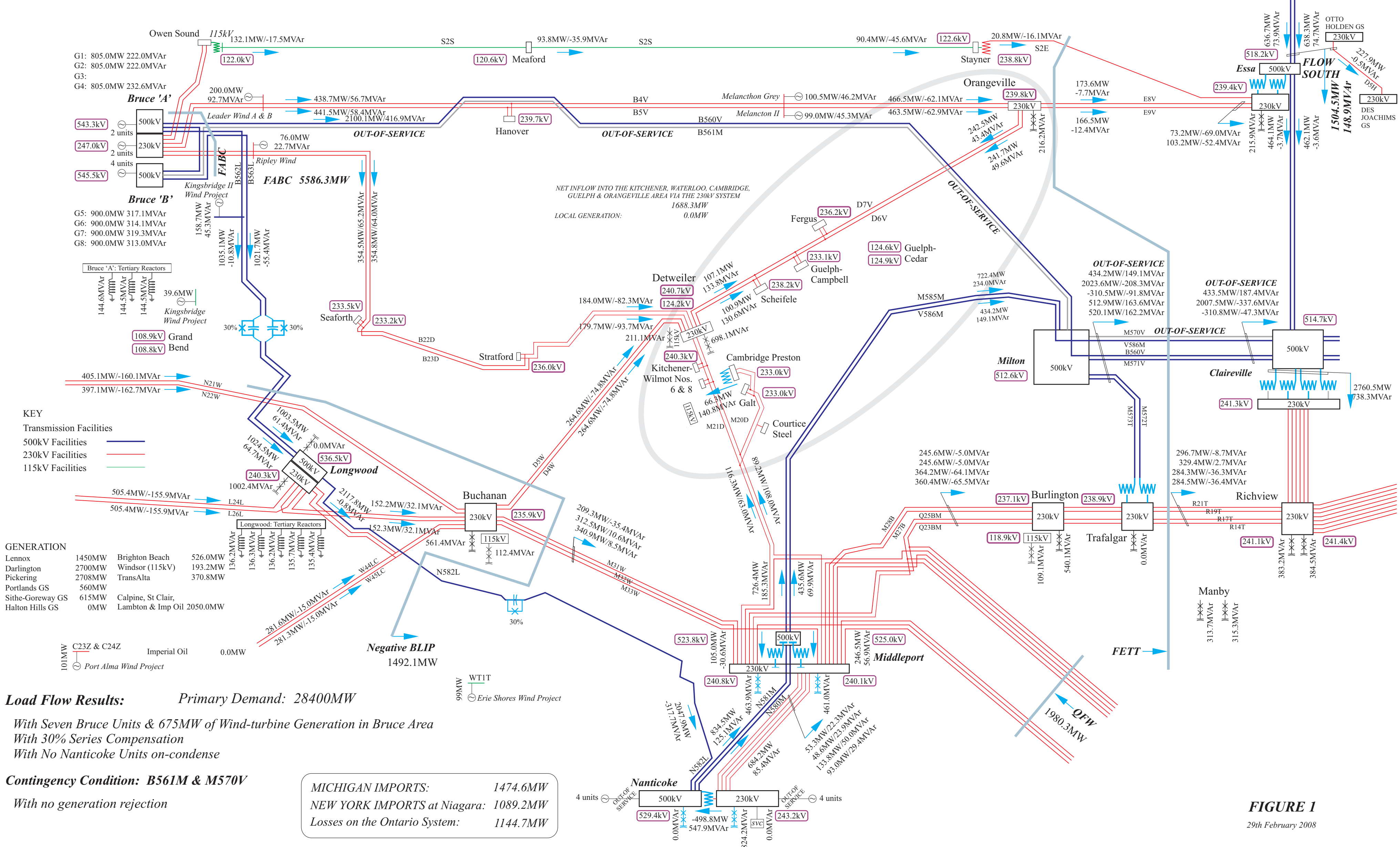
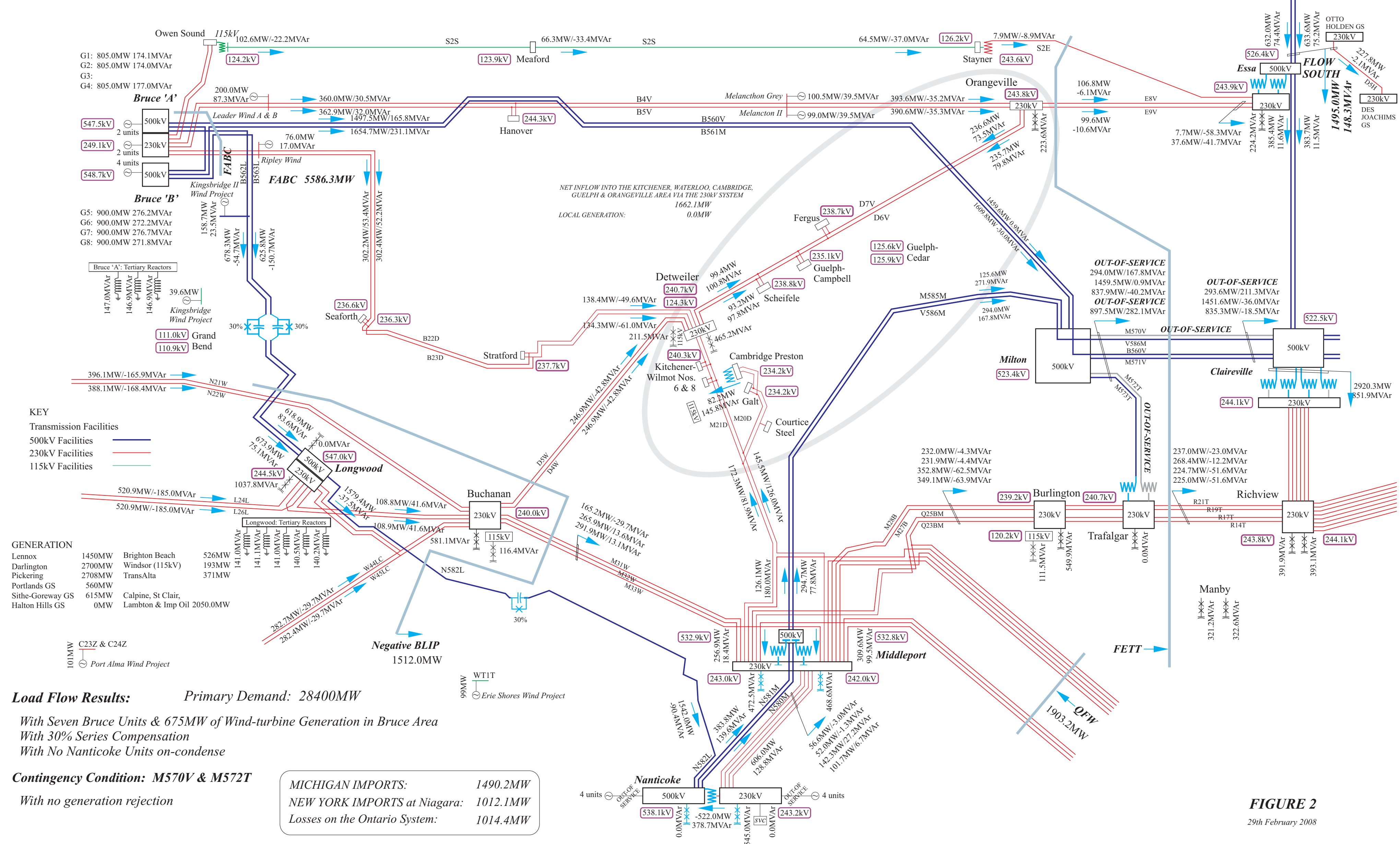


FIGURE 1

29th February 2008



Load Flow Results: *Primary Demand: 28400MW*

With Seven Bruce Units & 675MW of Wind-turbine Generation in Bruce Area
With 30% Series Compensation
With No Nanticoke Units on-condense

Contingency Condition: M570V & M572T

With no generation rejection

MICHIGAN IMPORTS:	*1490.2MW*
NEW YORK IMPORTS at Niagara:	*1012.1MW*
Losses on the Ontario System:	*1014.4MW*

FIGURE 2

29th February 2008

Ontario Energy Board (Board Staff) INTERROGATORY #3.4 List 1

Interrogatory

Issue Number: 3.2
Issue: Can the proposed near term and interim measures be utilized longer than the suggested two to three year time frame?

Ref (a) B/Tab 6/Sch 5/Appendix 6/p. 39

Ref (b) B/Tab 6/Sch 5/Appendix 2(letter dated December 22, 2006 from OPA)/pp. 2 to 5

Ref.(c) Hydro One's response to Board Staff interrogatory No. 84 [J/Tab 1/Sch 84] - the "2007 and 2008 Electricity Transmission Revenue Requirements Hearing" (EB-2006-0501) – the interrogatory response included a copy of the Repor titled "Series Capacitor Application in Ontario:SSR Mitigation Final Report; Electric Systems Consulting, ABB Inc., Raleigh, NC, March 30, 2006".

Preamble:

(a) Based on information, see Ref.(a), provided by the OPA on future generation supply, the capacity supply in the Bruce area may start to decline in 2012/13 and fall to a minimum value in 2017/18.

(b) Assume that the interim measures including the 30% series compensation can be implemented with no risk to the system (subject to the findings of the study referred to in Ref. (b), last page) for two to three years.

Questions:

(i) Given the facts and assumptions in the Preamble (a), and (b), please provide an assessment whether or not the applicant, OPA or the IESO would agree that these interim measures can meet the system requirements for a period of seven to eight years? And if the answer is negative, please provide cogent analysis to support the notions that such a scenario would be viewed as excessively severe.

(ii) As an alternative to utilizing series compensation with fixed-value capacitors, as suggested in the ABB study referred to in Ref.(c), can the concept of series compensation be re-examined using thyrister- controlled capacitors to vary the amount of compensation in order to deal with the possibility of sub-synchronous resonance with nearby nuclear or fossil generating units? If the answer is affirmative, please provide a full argument in terms of cost premiums, and advantages in the long term for such an approach.

Response

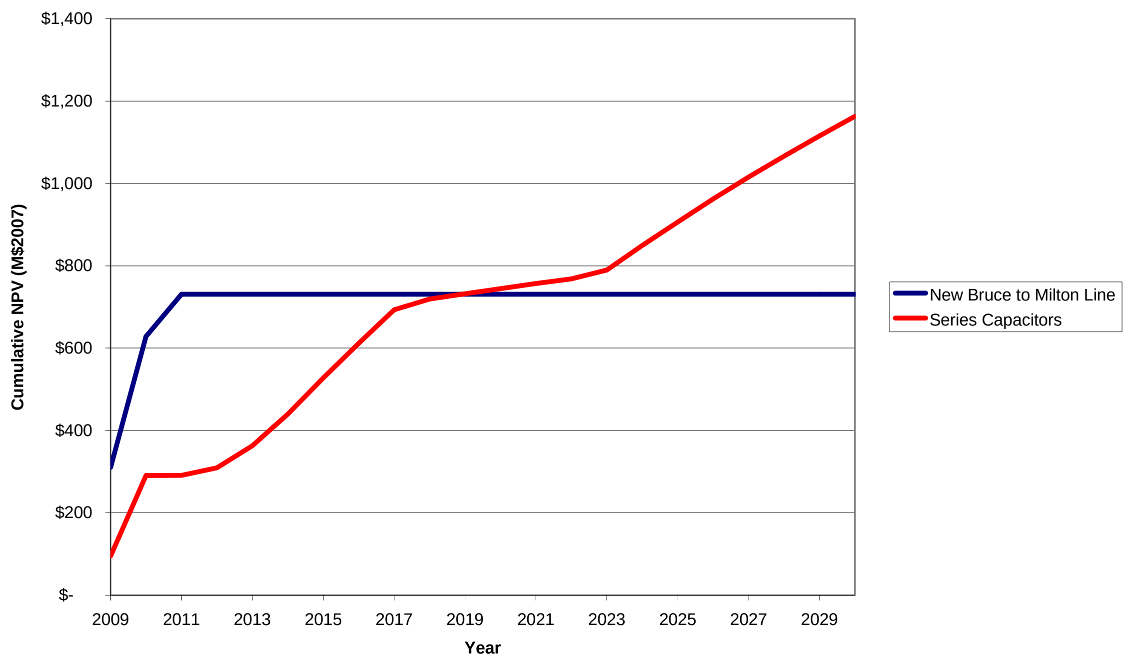
(i) As discussed in the response to Board Staff Interrogatory 3.2 (i) and (ii), the planned use of GR under normal operation is not appropriate unless there is a permanent long-term alternative under development and GR is used to bridge the gap between the need date and the in-service of the long-term solution. The use of series capacitors is possible, but there will be cost implications, namely: capital cost of the required facilities, the undelivered energy from the Bruce area, power losses, and renewable energy developments in the Bruce area.

In addition to these complexities, the OPA carried out an economic evaluation between the use of series capacitors as the long-term solution for the Bruce area, as compared to the proposed Bruce to Milton 500 kV line. For this study, the salient assumptions are listed below:

- As discussed at the technical conference (Day 1 Technical Conference Presentation Exhibit KT.1, slide 21) OPA's assumption is that the level of nuclear generation in the Bruce Area will remain at 6,400 MW (capacity of the 4 Bruce A and 4 Bruce B units) in the long-term. For the purpose of this economic assessment, the Bruce B units are assumed to be refurbished starting in 2018. This is based on publicly available information provided by Bruce Power.
- Capital costs of the Bruce to Milton line project and the series capacitor project are provided by Hydro One
- Generation rejection (GR) is not employed on a permanent basis as this is an assessment of long-term solutions.
- All the future wind generation (1,000 MW) is assumed to come in-service whether series capacitors are used or the new Bruce to Milton line.

The results of the economic assessment are presented in the form of cumulative net present values and are summarized in the graph below. In comparing the applied-for Bruce to Milton Project with the series capacitor option, the economic assessment shows that the Bruce to Milton alternative is the preferred long term economic choice as the total costs (comprised of capital, undelivered energy and transmission losses) are minimized. It must also be noted that the series capacitors alternative does not meet the identified need. Also, the analysis presented does not consider the increased difficulty of operating a system that implements series capacitors. These operational problems are explained in detail earlier in this question, as well as in the response to Board Staff Interrogatory 3.2.

Cumulative Net Present Value of Costs for the use of the Bruce to Milton Line and Series Capacitors



(ii) Thyristor Controlled Series Capacitors (TCSC) are not needed at 30% compensation. This is explained in the response to Board Staff question 3.1 part (v).

Ontario Energy Board (Board Staff) INTERROGATORY #3.5 List 1

Interrogatory

Issue Number: 3.2

Issue: Can the proposed near term and interim measures be utilized longer than the suggested two to three year time frame?

Ref (a) B/Tab 3/Sch 1

Ref (b) B/Tab 6/Sch 5

Preamble:

The second paragraph on page 1 of Ref (a) outlines a number of short term and interim measures that the OPA has recommended. It is further stated that Hydro one intends to proceed with these measures, other than series compensation which is pending the results of a due diligence study to be undertaken by the OPA. Figure 1 on page 2 of Ref. (a) shows that the near term improvements will add approximately 300 MW to the transmission capability but there is no indication of the impact of the interim measures on transmission capacity. Figure 2.3.1 on page 52 of Ref. (b) shows that the proposed series compensation would add approximately 1300 MW to the transmission capability and the generation rejection scheme would add an additional approximately 700 MW for a total transmission capability of approximately 7300 MW. Board staff wishes to explore the impact of the proposed interim measures on transmission capacity and the timing of the proposed new transmission facilities.

Questions/Requests:

(i) What is the current status and expected timing of the proposed generation rejection scheme?

(ii) If Hydro One expects to proceed with the series compensation installation, what is the proposed completion date for that installation?

(iii) Please advise what is the impact on the transmission capacity and timing of need for the proposed 500 kV circuits associated with:

a. the proposed generation rejection scheme; and

b. the proposed series compensation on existing 500 kV circuits in the area of the Bruce Complex.

(iv) What is the maximum Bruce generation and wind generation that can be accommodated with all the short term and interim measures in place?

(v) Are there any additional mitigating measures that can extend the adequacy of the transmission capability in the area of the Bruce Complex? If so, please provide a description of the measures, benefits provided and cost of implementation.

Response

(i) Modifications to the existing Bruce Special Protection System required to allow for the rejection of wind farm generation is under construction and expected to be completed by Spring 2008. Additional contingency coverage, as requested by IESO, is in the engineering design phase and is expected to be in service by May 2010.

(ii) Subject to applicable regulatory approvals, the series compensation will be installed 30 to 36 months after the receipt of applicable recommendations from OPA.

(iii) a) As explained during the Technical Conference (see Day 1 Technical Conference Presentation Exhibit KT.1 slides 35 to 42) the near-term measures and the generation rejection (GR) interim measure increase the transfer capability of the Bruce system from 5,385 MW to 6,326 MW until the line is placed in-service in December 2011. The need date for the long-term solution is 2009 and is unaffected by the use of these measures.

b) As explained during the Technical Conference (see Day 1 Technical Conference Presentation Exhibit KT.1 slide 42), the use of series capacitors as an interim measure is proposed if there are significant delays in the in-service of the proposed Bruce to Milton line. This interim measure, along with other interim measures (such as GR) and near-term measures are expected to increase the transfer capability of the Bruce system to 7,076 MW. However, interim solutions are only appropriate as a stop-gap and until appropriate long-term solutions can be implemented. The long-term need identified in these circumstances remains 2009 and implementation of a solution to meet that long-term need is necessary.

(iv) As explained during the Technical Conference (see Day 1 Technical Conference Presentation Exhibit KT.1 slides 35 to 42), the near-term measures and the G/R scheme will allow generation from 7 Bruce Units and the committed wind to be accommodated. However, GR cannot be used on a permanent basis, as explained in the response to Board Staff Interrogatory 3.2.

Series capacitors, in addition to the near-term measures and the G/R scheme, will allow adequate transfer capability for approximately 8 Bruce Units and 700 MW of wind generation. However, as mentioned above, GR cannot be used on a permanent basis.

(v) As explained during the Technical Conference (see Day 1 Technical Conference Presentation Exhibit KT.1 slides 35 to 42), no other mitigating measures have been contemplated beyond the planned near-term measures, GR scheme and series compensation. These measures are feasible and can be implemented in the time frame required.

Ontario Energy Board (Board Staff) INTERROGATORY #4.1 List 1

Interrogatory

Issue Number: 4.1
Issue: For the preferred option, does the project meet all the requirements as identified in the System Impact Assessment and the Customer Impact Assessment?

Ref (a) B/Tab 6/Sch 2 (IESO System Impact Assessment Report)/Sec. 3/p. 3

Ref (b) Transmission Rate Hearing, EB-2005-0501/D2/Tab 2/Development Capital Projects

Preamble:

(a) In Ref.(a), the SIA indicated that shunt capacitor banks were recommended in an earlier SIA report for installation at Detweiler TS, Orangville TS, Middleport TS, and Nanticoke TS;

(b) In Ref.(b), Hydro One indicated that it intends to install Static-Var Compensators at Nanticoke [instead of shunt capacitors as stated in Ref.(a)] and shunt capacitors at Detweiler and Orangeville. There was no mention of installing shunt capacitors at Middleport.

Questions:

(i) Please provide the explanation for deciding to install SVCs at Nanticoke instead of shunt capacitors given that the shunt capacitors' cost is in the order of $ 5 million versus the SVCs which cost about $ 50 million;

(ii) Please indicate whether or not Hydro One intends to install shunt capacitors at Middleport. If not, please provide explanation why these shunt capacitors will not be needed.

Response

(i) Due to its location on the transmission system, Nanticoke requires a mixture of static (shunt capacitors) and dynamic (SVCs) reactive sources. While shunt capacitors have continuous output, SVCs provide flexibility by varying its output to automatically respond to contingency scenarios. Hydro One installs shunt capacitors to the maximum extent possible; however it must also rely on SVCs to ensure reliable transmission service.

(ii) The installation of four 250 MVAr shunt capacitor banks for Middleport TS will be placed in service commencing in May 2009.

Ontario Energy Board (Board Staff) INTERROGATORY #4.2 List 1

Interrogatory

Issue Number: 4.1
Issue: For the preferred option, does the project meet all the requirements as identified in the System Impact Assessment and the Customer Impact Assessment?

Ref B/Tab 6/Sch2 (IESO System Impact Assessment Report)/Sec. 8.2 Contingency Conditions/scenario iv./p. 11

Preamble:

The SIA states "It is therefore recommended that the proposed layout of the 500kV busbar at Milton TS be reviewed to avoid the simultaneous loss of the 500kV circuit M573T and either of the 500kV Milton-to-Claireville circuits due to a breaker-failure condition involving either of the 500kV breakers L70L73 or HL573."

Questions:

Did Hydro One review the layout of the 500 kV busbar at Milton to address the concern raised by the IESO in the Preamble. Please provide a status of that review along with Hydro One's conclusion and action plan to address this issue.

Response

Hydro One reviewed the Milton TS arrangement and is planning to implement the IESO's recommendation.

Ontario Energy Board (Board Staff) INTERROGATORY #4.3 List 1

Interrogatory

Issue Number: 4.1
Issue: For the preferred option, does the project meet all the requirements as identified in the System Impact Assessment and Customer Impact Assessment?

Ref A/Tab 2/Sch 1/System Impact Assessment

Preamble:

Page 17 of the System Impact Assessment indicates that the following facilities must be in service once the new 500 kV line is in service, but are expected to be in service prior to line to mitigate operational issues starting in 2009:

- Shunt capacitor banks at Detweiler TS and Orangeville TS;
- Buchanan TS A 3rd 170MVAr shunt capacitor bank;
- Middleport TS Two 400MVAr shunt capacitor banks;
- Nanticoke SS At least one 250MVAr shunt capacitor bank;
- Nanticoke SS Dynamic compensation with a capacity of at least +350/-120MVAr .

Questions/Requests:

i. Please provide a brief description of the status of each of the above-noted recommended facilities including the expected completion dates.

ii. If the expected completion dates are later than 2009, what plans does Hydro One have for dealing with the operational issues that will arise?

Response

(i) The Orangeville & Detweiler capacitor banks are under construction with an expected in-service date of Spring 2008. Buchanan, Middleport, Nanticoke capacitor banks are all scheduled for staggered in-service between May and October 2009. OPA changed the recommended size of these installations to: Buchanan – 1x200 MVAr, Middleport – 4x250 MVAr, Nanticoke – 2x250 MVAr. The SVCs for Nanticoke are still in the project development phase. OPA has advised Hydro One that they are also considering an SVC for Detweiler TS.

(ii) The only facility with an expected completion date later than 2009 is the Nanticoke SVCs. In the event that any of the noted facility requirements cannot be met within the identified timeframe, Hydro One or other market participants would propose alternatives for IESO review and consideration.

Ontario Energy Board (Board Staff) INTERROGATORY #4.4 List 1

Interrogatory

Issue Number: 4.1
Issue: For the preferred option, does the project meet all the requirements as identified in the System Impact Assessment and Customer Impact Assessment?

Ref B/Tab 6/Sch 2 (IESO System Impact Assessment Report)/Sec 9.1/p. 14 and Diagram 19 & 20

Preamble:

With regard to the IESO simulation projecting Bruce area generation of 8 Nuclear units, 725 MW of committed wind generation, a further 870 MW of additional generation capacity and a system load of 28,400 MW, the IESO states that "outages involving the transmission facilities that form the Milton-Claireville corridor would be especially challenging operationally and that this corridor would benefit from the implementation of measures that would limit the severity of the critical outage conditions."

Questions:

Does the Applicant agree with this assessment and if so what measures does the Applicant intend to implement?

Response

Hydro One agrees with IESO's assessment concerning the operational challenges associated with the Milton-Claireville corridor. These matters are being investigated further and are likely to be considered as part of the IPSP process.

Ontario Energy Board (Board Staff) INTERROGATORY #4.5 List 1

Interrogatory

Issue Number: 4.2
Issue: Does the project meet applicable standards for reliability and quality of electricity service?

Ref B/Tab 6/Sch 2(IESO System Impact Assessment Report)/ p. 1 and Diagram 2

Preamble:

The IESO has recommended an additional circuit breaker at the Bruce A TS at the termination location of the proposed transmission line.

Questions:

(i) Does the Applicant intend to install the additional breaker recommended by the IESO to avoid having the T27 autotransformer directly connected to the E-bus?

(ii) Would adding yet another breaker (to avoid having the T25 autotransformer directly connected to the A-bus) make sense in order to add more security to the system for events such as double contingencies?

Response

(i) No. Based on further reviews conducted by the IESO and Hydro One this breaker is no longer required.

(ii) This is not a reliability requirement. The IESO suggested that Hydro One consider this arrangement because it would provide enhanced flexibility to carry out maintenance work.

Ontario Energy Board (Board Staff) INTERROGATORY #4.6 List 1

Interrogatory

Issue Number: 4.2
Issue: Does the project meet applicable standards for reliability and quality of electricity service?

Ref B/Tab 6/Sch 2(IESO System Impact Assessment Report)/Sec 8.2/p. 11 and Diagram 10

Preamble:

In the IESO's review of a breaker failure contingency and the simultaneous loss of a 500 kV Milton to Claireville circuit and a 500 kV Milton to Trafalgar circuit, the IESO states that under some operating scenarios the 10 day LTR rating of autotransformer T14 at Trafalgar could be exceeded.

Questions:

Is it the intention of Hydro One to re-configure the layout of the 500 kV switching facilities at Milton SS to avoid the possibility of a simultaneous loss of the M573T circuit and either of the Milton to Claireville circuits in the event of a failure involving either circuit breaker L70L73 or circuit breakers HL73 at Milton SS? and if not, why not?

Response

Further Milton reconfigurations are under consideration, for implementation in 2016 along with the autotransformers recommended by OPA in the IPSP.

Ontario Energy Board (Board Staff) INTERROGATORY #5.1 List 1

Interrogatory

Issue Number: 5.1
Issue: Are the forms of land agreements to be offered to affected landowners reasonable?

Ref B/Tab 6/Sch 10/Appendices 1-8

Preamble:

Hydro One included the following forms of agreements in its pre-filed evidence in support of s. 92 application:

- Easement Agreement
- Agreement of Purchase and Sale
- Offer to Grant an Easement
- Option to Purchase
- Damage Claim Form
- Damage Release Form
- Testing and Associated Access Routes
- Off-Corridor Temporary Access Roads

Questions:

a. Is Hydro One seeking approval of the Board for each agreement listed in the preamble? Please explain the rationale for your response.

b. What is Hydro One's strategy to offering each agreement listed in the preamble to the affected landowners?

c. What is the status of Hydro One's acquisition of each agreement listed in the preamble from the affected landowners?

d. What are the types and amounts of costs that Hydro One expects to incur upon executing each agreement listed in the preamble?

e. Approximately, how many properties will be affected by each agreement listed in the preamble?

Response

a. Hydro One is seeking approval of the agreements required for the acquisition of interests in land, namely the easement and purchase and sale agreements. The other enumerated agreements and forms for which Hydro One's not seeking approval relate to ancillary matters, such as the granting of options to acquire interests in land and agreements relating to any damage payments arising due to the construction of the Project.

b. Through the negotiation process, property owners will be offered a choice as to the preferred tenure of the taking being either an easement or fee simple interest.

   Off-corridor access, Temporary Access and Damage Claims will be negotiated and/or handled on a case by case basis with each property owner affected by the construction activities and access requirements.

c. To date, Hydro One has negotiated a limited number of Off-Corridor Temporary Access Agreements in order to undertake certain geotechnical soils investigations.

   Hydro One is expecting to commence its land acquisition process with the presentation of offers to landowners based upon independent third party appraisals. Offers made are expected to be in the form of an Option Agreement to property owners. The contemplated approach is that Hydro One will acquire an option (i.e. the right but not the obligation) to acquire either an easement or fee interest from affected property owners prior to receiving all necessary regulatory and environmental approvals. If all regulatory approvals are satisfactorily obtained, Hydro One would then be in a position to exercise the options and acquire the necessary interests in land.

d. As reported in the pre-filed evidence, Exhibit B, Tab 4, Schedule 1, $125M has been budgeted for acquisition of property rights and related costs including staffing costs associated with these acquisitions. A cost estimate per agreement is not available.

e. A breakdown of the number of properties expected to be affected by each agreement is not available at this point as negotiations with landowners have not commenced. Hydro One expects the majority of the types of property interests to be acquired will be grants of easements. Fee simple acquisitions for some of the new corridor interests and total property buyouts will also be required.

There will be a limited number of properties where Temporary Access and Off-corridor Access rights are required to support the construction program.

Damage Claims will be handled on a case by case basis in response to individual property owner claims.

Ontario Energy Board (Board Staff) INTERROGATORY #5.2 List 1

Interrogatory

Issue Number: 5.2
Issue: What is the status and process for Hydro One's acquisition of permanent and temporary land rights required for the project?

Ref B/Tab 6/Sch 9/pp. 4-6

Questions:

Referring to current project construction and in-service schedule, please discuss Hydro One's schedule and prospects to acquire necessary permanent and temporary land rights.

Response

With reference to the project schedule (Exhibit B, Tab 5, Schedule 2, as updated November 30, 2007), project construction is planned to commence on publicly held land in January 2009, after Environmental Assessment and Ontario Energy Board S.92 approvals are received.

Hydro One proposes to commence property acquisition negotiations with individual property owners within the next few months. These negotiations will continue through 2008 and 2009, as necessary. Subject to receiving regulatory and EA approvals, Hydro One expects that a significant number of private property owner agreements will be secured to facilitate scheduling construction in early 2009.

Hydro One plans to have the project constructed and in service by December 2011, as per the schedule in Exhibit B, Tab 5, Schedule 2 (as updated November 30, 2007).

It may be necessary for Hydro One to make application under S.99 of the OEB Act to expropriate rights for a limited number of private properties. That application, if necessary, is not currently planned to be made until after an EA approval has been granted, which is assumed to occur in Q1 2009.

Ontario Energy Board (Board Staff) INTERROGATORY #6.1 List 1

Interrogatory

Issue Number: 6.1
Issue: Have all Aboriginal Peoples whose existing or asserted Aboriginal or treaty rights are affected by this project been identified, have appropriate consultations been conducted with these groups and if necessary, have appropriate accommodations been made with these groups?

Ref B/Tab 6/Sch 7

Preamble:

According to its pre-filed evidence Hydro One identified potentially affected Aboriginal Groups (defined by Hydro One as First Nations and the Métis) and that initial consultations with these Aboriginal Groups have commenced or are planned to commence and continue.

Questions:

a) Identify all of the Aboriginal Groups that have been contacted in respect of this application.

b) Indicate:

i) how the Aboriginal Groups were identified;

ii) when contact was first initiated;

iii) the individuals within the Aboriginal Group who were contacted, and their position in or representative role for the group;

iv) a listing, including the dates, of any phone calls, meetings and other means that may have been used to provide information about the project and hear any interests or concerns of Aboriginal Groups with respect to the project.

c) Provide relevant information gathered from or about the Aboriginal Groups as to their treaty rights, or any filed and outstanding claims or litigation concerning their treaty rights or treaty land entitlement or aboriginal title or rights, which may potentially be impacted by the project.

d) Provide any relevant written documentation regarding consultations, such as notes or minutes that may have been taken at meetings or from phone calls, or letters received from, or sent to, Aboriginal Groups.

e) Identify any specific issues or concerns that have been raised by Aboriginal Groups in respect of the project and, where applicable, how those issues or concerns will be mitigated or accommodated.

f) Explain whether any of the concerns raised by Aboriginal Groups with respect to the applied-for project have been discussed with any government department or agencies, and if so, identify when contacts were made and who was contacted.

g) If any of the Aboriginal Groups who were contacted either support the application or have no objection to the project proceeding, identify those groups and provide any available written documentation of their position. Also, indicate if their positions are final or preliminary or conditional in nature.

h) If any of the Aboriginal Groups who were contacted are opposed to the application, identify those groups and provide any available written documentation of their position. Also, indicate if their positions are final or preliminary or conditional in nature.

i) Provide details of any know Crown involvement in consultations with Aboriginal Groups in respect of the applied-for project.

Response

This interrogatory response updates Hydro One's March 29, 2007 Application at Exhibit B, Tab 6, Schedule 7, regarding its engagement program with the First Nations and Métis peoples noted below that may have an interest in, or may be potentially affected by, the Project (the "Aboriginal Groups").

a) Hydro One originally identified in the Application the following Aboriginal Groups who may have an interest in, or may be potentially affected by, the Project: the Chippewas of Saugeen, the Chippewas of Nawash (together, the Saugeen Ojibway Nation ("SON")), the Mississaugas of New Credit, the Six Nations of the Grand River, including the Haudenosaunee Six Nations Confederacy Council, the Georgian Bay Metis Council, the Grey Owen Sound Metis Council, and the Saguingue Metis Council.

Since the Application was filed Hydro One has also identified the Huronne Wendat of Wendake, Quebec as being potentially interested and affected by the Project as this group has made claims over a portion of the lands upon which the Project will traverse.

Also, Hydro One has corresponded with the Metis Nation of Ontario and met with representatives of this group on February 11, 2008. Future meetings are planned.

b) Prior to submitting the Application, Hydro One undertook a due diligence exercise to determine which Aboriginal Groups should be included in its engagement program relating to the Project; the fundamental question posed was who may have an interest in, or may be potentially affected by, the Project? In addition to its own internal work on this question, Hydro One also received information from the (then) Ontario Native Affairs Secretariat (now the Ontario Secretariat for Aboriginal Affairs, or "OSAA") and the federal Department of Indian and Northern Affairs. Hydro One has not been made aware by these or other ministries or departments of any other Aboriginal Group in respect of which the Crown has knowledge, real or constructive, of the existence or potential existence, of an Aboriginal right or treaty right which the Crown contemplates the proposed Bruce to Milton Project might adversely affect. Hydro One's discussions with the Ministry of Energy and other Ministries is an ongoing process.

All of the identified Aboriginal Groups have received correspondence from Hydro One providing them with information regarding the Project and inviting them to express any concerns or issues they might have directly to Hydro One.

Attached as Attachment A is a complete listing of all of Hydro One's interactions, along with a compilation of correspondence, meeting notes or minutes, as may be appropriate, with the Aboriginal Groups as of February 29, 2008. Note that in excess of one hundred phone calls have been made to the Aboriginal Groups that have expressed an interest in meeting with Hydro One to discuss the project and the Aboriginal Groups' interests and concerns.

c) As noted in response (b) to this interrogatory, Hydro One has been in communication with applicable government ministries and agencies respecting the identification of Aboriginal Groups whose interests may be potentially affected by the Project and in respect of the consultation process. Hydro One has understood information used by the Crown in the Aboriginal consultation process would include the consideration of applicable treaties and asserted claims.

For example, Hydro One was made aware by OSAA that the Chippewas of Nawash Unceded First Nation and the Saugeen First Nation have asserted, in ongoing litigation, a claim to parts of the Bruce Peninsula and to rights to hunt, fish and gather that appear to relate to the area through which the proposed transmission line would run. In separate litigation, they have also asserted a claim to aboriginal title to portions of the bed of Lake Huron.

OSAA also advised that there are, at present, no active land claims in the OSAA land claim process that have been submitted by the Chippewas of Saugeen and Nawash First Nations that relate to the lands in question.

OSAA also advised that the applied-for general route for the Bruce to Milton Project appears to traverse through the Haldimand Tract area. The Six Nations of the Grand River have asserted a claim in relation to the Haldimand Tract and are also involved in litigation related to the tract. OSAA advised that the Government of Ontario is negotiating with the Six Nations of the Grand River concerning their claim.

d) Attached as Attachment A is a complete listing of all of Hydro One's interactions, along with a compilation of correspondence, meeting notes or minutes, as may be appropriate, with the Aboriginal Groups as of February 29, 2008.

Hydro One has provided an extensive amount of information to the Aboriginal Groups regarding the Application and the Project generally. Hydro One has extended offers to meet with all of the Aboriginal Groups with its offers to date being accepted by the SON and the Six Nations (Haudenosaunee and Band) and the Metis Nation of Ontario. To assist in this effort both on the Project and more broadly at a corporate level, Hydro One has hired a full-time Director of Aboriginal Relations.

Hydro One is committed to continuing to engage with the Aboriginal Groups to continue to share Project-related information, understand and, where possible, address their issues and concerns regarding the Project and to continue to engage with them both before the OEB hearing process and also after any approvals are issued and throughout the construction and operation phases of the Project.

e) The Haudenosaunee have raised concerns regarding how the Project may affect Haudenosaunee and other Aboriginal human burials. Hydro One has discussed its archaeological procedures and program with the Haudenosaunee in respect of the Project and is currently discussing a potential agreement with the Haudenosaunee regarding archaeological matters and the Project.

The Haudenosaunee have also raised concerns regarding the potential environmental effects of the Project on the Haudenosaunee's environmental values. The Project is the subject of an environmental assessment. Hydro One is currently discussing this matter further with the Haudenosaunee.

Finally, Hydro One has entered into a protocol agreement with the Haudenosaunee to facilitate greater communication between the Haudenosaunee and Hydro One and to set out a general process for discussing further issues of concern, including those associated with the Project. Discussions are ongoing, with some of the issues raised by the Haudenosaunee being more appropriately dealt with within the context of the Project's environmental assessment.

Further details of Hydro One's discussions with the Haudenosaunee are at Attachment A, Six Nations Haudenosaunee and Band Council, Meeting Notes and Materials.

The Saugeen Ojibway Nation ("SON") has raised concerns about the Project, including the need for resources to participate in the Project's review processes, the Project's Attachment, the overall effect of the Project on the SON's asserted traditional territory, effects of the Project combined with other projects, local benefits to be derived from the Project, and the Crown's consultation process relating to the Project, among other issues. Discussions between the SON and Hydro One are ongoing, with many of these issues being more appropriately dealt with within the context of the Project's environmental assessment.

Further details of Hydro One's discussions with the SON are at Attachment A, Saugeen Ojibway Nation, Meeting Notes and Materials.

Finally, environmental issues and concerns are being addressed within the Project's environmental assessment process. Recent issues have focused on the Project's terms of reference for the environmental assessment, with issues being raised by both the SON and the Haudenosaunee. Working groups have been established with each of these Groups and regularly scheduled meetings are held to discuss issues of concern and, where possible, to address such issues. Discussions to date have focused on ways in which such groups can be involved in the environmental assessment process, including participation in studies (e.g. archaeological studies), the review of reports, the development of biodiversity initiatives, the identification and discussion of potential effects and mitigation measures, and identification and use of traditional knowledge that may be relevant to the environmental assessment.

Hydro One anticipates that these processes will continue throughout the course of the Project's environmental assessment.

Hydro One welcomes the involvement of any of the other Aboriginal communities and groups having an interest in the Project.

f) Hydro One has kept Ministry of Energy officials informed on consultation activities with identified Aboriginal Groups. Three channels of communication have been used for this purpose. On a weekly basis, Hydro One's Bruce to Milton Project Manager and the Ministry of Energy's Policy Analyst for the Office of Consumer and Regulatory Affairs discuss operational/project matters concerning prior week developments as well as those planned in the near term. This has included information regarding issues of concern with Aboriginal Groups. On a monthly basis, Hydro One's Vice President of Government Relations has also meet with counterparts at the Ministry of Energy (e.g. Assistant Deputy Minister) to advise and discuss the status of the Bruce to Milton Project. Consultations with identified Aboriginal Groups have often been discussed. Finally, Hydro One's Chair and President & CEO regularly meet with the Minister of Energy to discuss policy matters. These meetings have, from time to time, included discussion of the Bruce to Milton Project, including issues of concern to identified Aboriginal Groups identified during the consultative processes.

Attached as Attachment C is a listing of the meetings that have taken place in respect of the above processes.

g) At this time, Hydro One is not aware of Aboriginal Groups who expressly support or have no objection to the Project.

h) At this time, Hydro One is not aware of Aboriginal Groups who expressly oppose the Project. As noted above, the SON and the Haudenosaunee have expressed concerns regarding the Project, and Hydro One is discussing these concerns with both groups.

i) In addition to the Crown's involvement as noted at Question (f) above, please find attached at Attachment B correspondence provided by the Crown regarding Aboriginal Peoples consultation.

Attachment A

Bruce to Milton Transmission Reinforcement:

Aboriginal Peoples Engagement Reference Binder

(Available by CD on request)

Attachment B

Crown Supporting Information, re: Aboriginal Consultation

(Available by CD on request)

Attachment C

Meeting Dates between the Crown and Hydro One

Hydro One Chair/President & CEO meetings with Minister of Energy since October, 2007
October 15, 2007
November 7, 2007
December 14, 2007
January 18, 2008
February 11, 2008

Monthly meetings between Hydro One Vice President – External Relations and Assistant Deputy Minister – Ministry of Energy since August, 2007
August 31, 2007
September 13, 2007
October 3, 2007
November 1, 2007
December 3, 2007
December 13, 2007
January 10, 2008
February 4, 2008