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BY COURIER

March 25, 2008

Mr. Basil Alexander
Klippensteins
Barristers & Solicitors
160 John St., Suite 300
Toronto ON
M5V 2E5

Dear Mr. Alexander:

EB-2007-0050 – Hydro One Networks' Section 92 Bruce - Milton Transmission Reinforcement Application – Hydro One Networks' Response to Interrogatory Questions from Pollution Probe List 4 and List 5

I am attaching a paper copy of the responses to the interrogatory questions from Pollution Probe Interrogatory lists four and five (questions 24 to 51).

All Intervenors and the Ontario Energy Board will also be sent electronic text searchable Acrobat files by email for the following Interrogatory Responses:

OEB Staff List 2
Updated response to OEB Staff Interrogatory C-1-2.6
Pollution Probe List 4 and List 5
Energy Probe List 2, 3 and List 4
Ross Interrogatories to Hydro One List 1
Ross Interrogatories to the Ontario Power Authority List 1
Ross Interrogatories to the Independent Electricity System Operator List 1
Powerline Connection List 1

One complete paper copy of all the EB-2007-0050 Interrogatory Responses organized in binder sets will be sent to your attention shortly. Electronic text-searchable copy of interrogatory responses will also continue to be available for download from the Hydro One Networks regulatory website.

Sincerely,

ORIGINAL SIGNED BY ODED HUBERT

Oded Hubert

c. Ms. Kirsten Walli, Ontario Energy Board

Pollution Probe INTERROGATORY #24 List 4

Interrogatory

Ref. Exh. B/T 1/S 1/page 3 of 5
Issue Number 1.0
1.0 Issue: Project Need and Justification

Request

There is a reference, starting on line 13, to 700 MW of wind generation expected to be in service by 2009:

a) If this MW figure reflects something other than nameplate ratings, please describe what it reflects and how it was determined.

b) What capacity value will be attributed to this 700 MW for purposes of determining generation supply adequacy?

c) What annual MWH generation is expected from this 700 MW of wind generation, and how does this generation break down between summer and winter, and between on-peak and off-peak periods?

d) Please include an explanation as to how summer, winter, on-peak, and offpeak are defined.

Response

a) The 700 MW is the installed capacity (nameplate rating) of the existing and committed wind generation.

b) A capacity value equaling 20% of the installed capacity of the existing and committed wind generation in the Bruce area is assumed for its contribution to the Ontario supply adequacy determination. Please refer to response Interrogatory Saugeen 18.

c) The total annual energy expected from the 700 MW of existing and committed wind generation is 37,681 and 1,720,767 MWh respectively. Please refer to response to Pollution Probe Interrogatory 3. Simulated wind capacity factor data was split into the peak periods defined in the response to part d) of this Interrogatory. The results are shown in the table below.

Period	Energy (MWh)
Winter Peak	144,345
Winter Mid-Peak	164,411
Winter Off-Peak	382,825
Summer Peak	76,556
Summer Mid-Peak	113,177
Summer Off-Peak	229,709
Shoulder Mid-Peak	294,586
Shoulder Off-Peak	353,057

d) The seasons and peak periods are defined in the tables shown below.

Season	Months Included
Winter	December – March
Summer	June – September
Shoulder	April, May, October, November

	Winter	Summer	Shoulder
Peak	07:00-11:00 and 17:00 – 20:00 Weekdays	11:00-17:00 Weekdays	None
Mid-Peak	11:00-17:00 and 2000-2200 Weekdays	07:00-11:00 and 17:00-22:00 Weekdays	07:00-22:00 weekdays
Off-Peak	00:00-07:00 and 22:00-24:00 Weekdays; All hours weekends	00:00-07:00 and 22:00-24:00 Weekdays; All hours weekends	00:00-07:00 and 22:00-24:00 Weekdays; All hours weekends

Pollution Probe INTERROGATORY #25 List 4

Interrogatory

Ref. Exh. B/T 1/S 1/page 4 of 5
Issue Number 1.0
1.0 Issue: Project Need and Justification

Request

There is a reference, starting on line 2, to 1,000 MW of additional wind generation expected to be in service in the Bruce area:

a) If this MW figure reflects something other than nameplate ratings, please describe what it reflects and how it was determined.

b) What capacity value will be attributed to this 1,000 MW for purposes of determining generation supply adequacy?

c) What annual MWH generation is expected from this 1,000 MW of wind generation, and how does this generation break down between summer and winter, and between on-peak and off-peak periods?

Response

a) The 1,000 MW is the installed capacity (nameplate rating) of the future wind generation.

b) A capacity value equaling 20% of the installed capacity of the existing and committed wind generation in the Bruce area is assumed for its contribution to the Ontario supply adequacy determination. Please refer to response Interrogatory Saugeen 18.

c) The total annual energy from the 1,000 of the future wind generation is 2,512,068 MWh. Please refer to response Pollution Probe Interrogatory 3. Simulated wind capacity factor data was split into the peak periods defined in the response to part d) of the response to Pollution Probe Interrogatory 24. The results are shown in the table below.

Period	**Energy (MWh)**
Winter Peak	206,207
Winter Mid-Peak	234,873
Winter Off-Peak	546,892
Summer Peak	109,366
Summer Mid-Peak	161,681
Summer Off-Peak	328,156
Shoulder Mid-Peak	420,837
Shoulder Off-Peak	504,367

Pollution Probe INTERROGATORY #26 List 4

Interrogatory

Ref. Exh. B/T 6/S 5/Appendix 5
Issue Number 1.0
1.0 Issue: Project Need and Justification

Request

On page 8, there is a reference to rules, criteria, standards, and guidelines established by the IESO, NPCC, and NERC. Please provide a copy of or electronic references to all such rules, criteria, standards, and guidelines that affect electric transmission system planning, operation, and reliability.

Response

The electronic references to each of the above-requested rules, criteria, and standards are supplied below:

NERC

- http://www.nerc.com/~filez/standards/Reliability_Standards.html

NPCC
- http://www.npcc.org/documents/regStandards/Criteria.aspx

IESO
- http://www.ieso.ca/imoweb/manuals/marketdocs.asp

Pollution Probe INTERROGATORY #27 List 4

Interrogatory

Ref. Exh. B/T 3/S 1
Issue Number 1.0
1.0 Issue: Project Need and Justification

Request

Please identify the electric transmission load flow model or models used by the OPA, IESO, and/or Hydro One to evaluate the need for transmission system reinforcement and used by the OPA, IESO, and/or Hydro One to evaluate the alternatives referenced. Please include the version number of any such model.

Response

The Siemens PSS/E version 29 transmission load flow model was used to evaluate the need for transmission system reinforcement as well as to evaluate alternatives.

Pollution Probe INTERROGATORY #28 List 4

Interrogatory

Ref. Exh. B/T 6/S 2
Issue Number 1.0
1.0 Issue: Project Need and Justification

Request

Please provide saved cases in PTI-format, compatible with Siemens PSS/E version 30, for the most recent load flow studies performed by or for Hydro One, the OPA, and/or the IESO in studying the need for the proposed transmission line (including those studies that examine the existing system with and without the proposed transmission line and other proposed system enhancements).

Response

Please refer to the letter from Hydro One to the Board dated March 13, 2008, at page 5, with respect to paragraph 3 of Procedural Order 5. To better utilize the resources available at the IESO and to obtain the maximum benefit from those resources, the IESO has proposed that it should perform a reasonable number of studies for Pollution Probe, at their specific direction. The results of these studies would then be provided to Pollution Probe in a format suitable for filing as evidence.

Pollution Probe INTERROGATORY #29 List 4

Interrogatory

Ref. Exh. B/T 6/S 5/Appendix 5
Issue Number 1.0
1.0 Issue: Project Need and Justification

Request

a) Please identify and discuss any reliability-based limitations considered by the OPA, the IESO, and/or Hydro One regarding how many electric transmission circuits may be placed within a common right-of-way corridor.

b) Please identify and discuss any reliability-based limitations considered by the OPA, the IESO, and/or Hydro One regarding how many electric transmission circuits may be placed on a common set of transmission towers.

c) Please identify and discuss any reliability-based limitations considered by the OPA, the IESO, and/or Hydro One regarding how much electric generating capacity, in relation to system peak load or other metric, may be installed at one location

Response

a) Please see the response to Board Staff Interrogatory 2.10(ii).

b) There is no reliability-based limitation on the number of circuits that may be placed on a transmission structure. The IESO considers the potential loss of two adjacent circuits on a common tower, as a recognized contingency for bulk power system elements in Ontario. In addition, the more severe loss of all circuits on a common right-of-way is assessed as explained in a).

c) The reliability-based limitation considered by the IESO regarding how much electric generating capacity may be installed at one location is based on two factors:

- The IESO assesses the loss of the entire capability of a generating station as an extreme contingency, as described in the response to question a). There are no specific requirements that would restrict the size of a generating plant in relation to system peak load or any other planning criterion; and

- The size of the individual generating units determines the amount of the 10 minute operating reserve (included as part of NPCC criteria). The additional operating reserve required for the 30 minute operating reserve is also determined by the size of the generating units, and is equivalent to half of the capacity of the next-largest generating unit.

Pollution Probe INTERROGATORY #30 List 4

Interrogatory

Ref. Technical Conference Panel One (Oct 15, 2007) slide presentation, slide 11 of 43.
Issue Number 1.0
1.0 Issue: Project Need and Justification

Request

The referenced material describes the existing transmission system's capability as being limited by required voltage performance following contingencies.

a) Please describe the system's required voltage performance and provide a copy of or a reference to such requirements.

b) Please describe or provide a reference to a description of the contingencies that cause the system to violate its required voltage performance.

c) Please describe or provide a reference to a description of the magnitude and location of the voltage violations that occur with each of the contingencies described in part (b) above.

d) Please describe the generation dispatch and system import assumptions that were used in determining the voltage violations.

e) Please provide saved case(s) in PTI-format, compatible with Siemen's PSS/E version 30, for the load flow studies performed by or for Hydro One, the OPA, and/or the IESO in determining these voltage violations.

Response

a) The following has been extracted from the IESO's *Ontario Resource and Transmission Assessment Criteria* and describes the minimum requirements that must be satisfied to ensure Steady State and Transient Voltage Stability.

From the *Ontario Resource and Transmission Assessment Criteria* Document

4.4 Transient Voltage Criteria

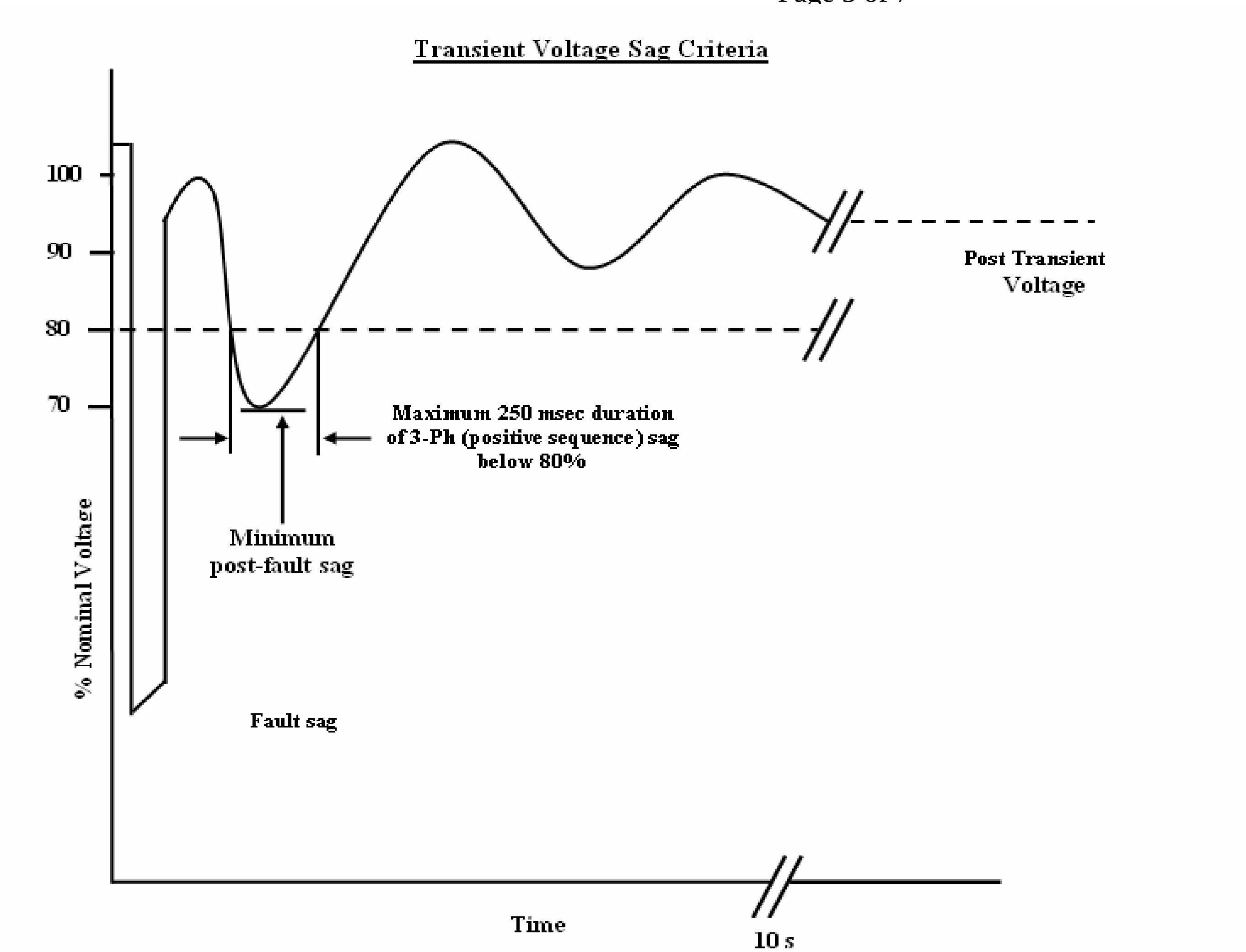
In cases where protection or control coordination may be an issue, or where significant induction motor load is present, time domain simulations should be conducted to assess the dynamic voltage performance. These simulations should cover a time frame in which ULTCs operate (<30 seconds) and should include modeling of devices which affect voltage stability (such as induction motors, ULTCs, switched shunts, generator field current limiters, etc). Per section 3.3.1, due regard should be given to reclosure operations in the simulation.

For transient voltage performance, studies should be done with a load model representative of the actual load. If that information is not available, the standard voltage dependent load model of P=50, 50, Q=0, 100 is to be used (see section 2.4 Load Forecasts and Load Modelling).

This criterion is not intended to be used as a standard of utility supply to individual customers, nor used for transmission and distribution protection design. Rather it is intended to avoid uncontrolled, significant load interruption that may lead to unintended transmission system performance. The starting voltage, sag and duration of post-fault transient undervoltages are a measure of the system strength, and its ability to recover promptly.

The following transient voltage criteria are to be used to evaluate system performance. The IESO will conduct periodic review of the IEEE standards and relevant literature to monitor the need to revise this section.

The minimum post-fault positive sequence voltage sag must remain above 70% of nominal voltage and must not remain below 80% of nominal voltage for more than 250 milliseconds within 10 seconds following a fault. Specific locations or grandfathered agreements may stipulate minimum post-fault positive sequence voltage sag criteria higher than 80%. IEEE standard 1346-1998 supports these limits.



Mitigation options include high-speed fault clearing, *special protection systems*, field forcing, transmission reinforcements and transmission interface transfer limits.

While the determination of whether a transient stability test is stable or unstable is generally straightforward, issues such as transient load shake-off, high voltage tripping of capacitors, and undamped oscillatory behaviour in the post-transient period should be considered using the following guidelines:

- occasional tests should be run out to about thirty seconds - first swing stability does not guarantee transient stability;
- high voltage swings will generally be considered acceptable unless the magnitude or duration of the high voltage swing could be sufficient to cause capacitor tripping. Typical maximum voltage and duration of swing to avoid damage to and tripping of high voltage capacitors are identified below. The magnitude of the high voltage swing must be less than the capacitor breaker rating multiplied by the factor in the following table for the duration indicated.

Duration	Maximum Permissible Voltage (Multiplying Factor To Be Applied to Rated RMS Voltage)
½ cycle	3.0
1 cycle	2.7
6 cycles	2.2
15 cycles	2.0
1 second	1.7
15 seconds	1.40

4.5 Steady State Voltage Stability

Adequate voltage performance under 4.4 above does not guarantee system voltage stability. Steady state stability is the ability of the *IESO-controlled grid* to remain in synchronism during relatively slow or normal load or generation changes and to damp out oscillations caused by such changes.
The following checks are carried out to ensure system voltage stability for both the pre-contingency period and the steady state post-contingency period:

- Properly converged pre- and post-contingency powerflows are to be obtained with the critical parameter increased up to 10% with typical generation as applicable;

- All of the properly converged cases obtained must represent stable operating points. This is to be determined for each case by carrying out P-V analysis at all critical buses to verify that for each bus the operating point demonstrates acceptable margin on the power transfer as shown in the following section; and

- The damping factor must be acceptable (the real part of the eigenvalues of the reduced Jacobian matrix are positive).

The following sections provide more information on damping factor, use of P-V curves to identify stability limits, and dynamic voltage performance simulations.

4.3 Power – Voltage (P-V) Curves

To generate the P-V curve, loads should be modeled as constant MVA. In specific situations, if good data is available, voltage dependent loads and tap-changer action may be modeled in detail to assess the system voltage performance following the contingency and automatic equipment actions but before manual operator intervention.

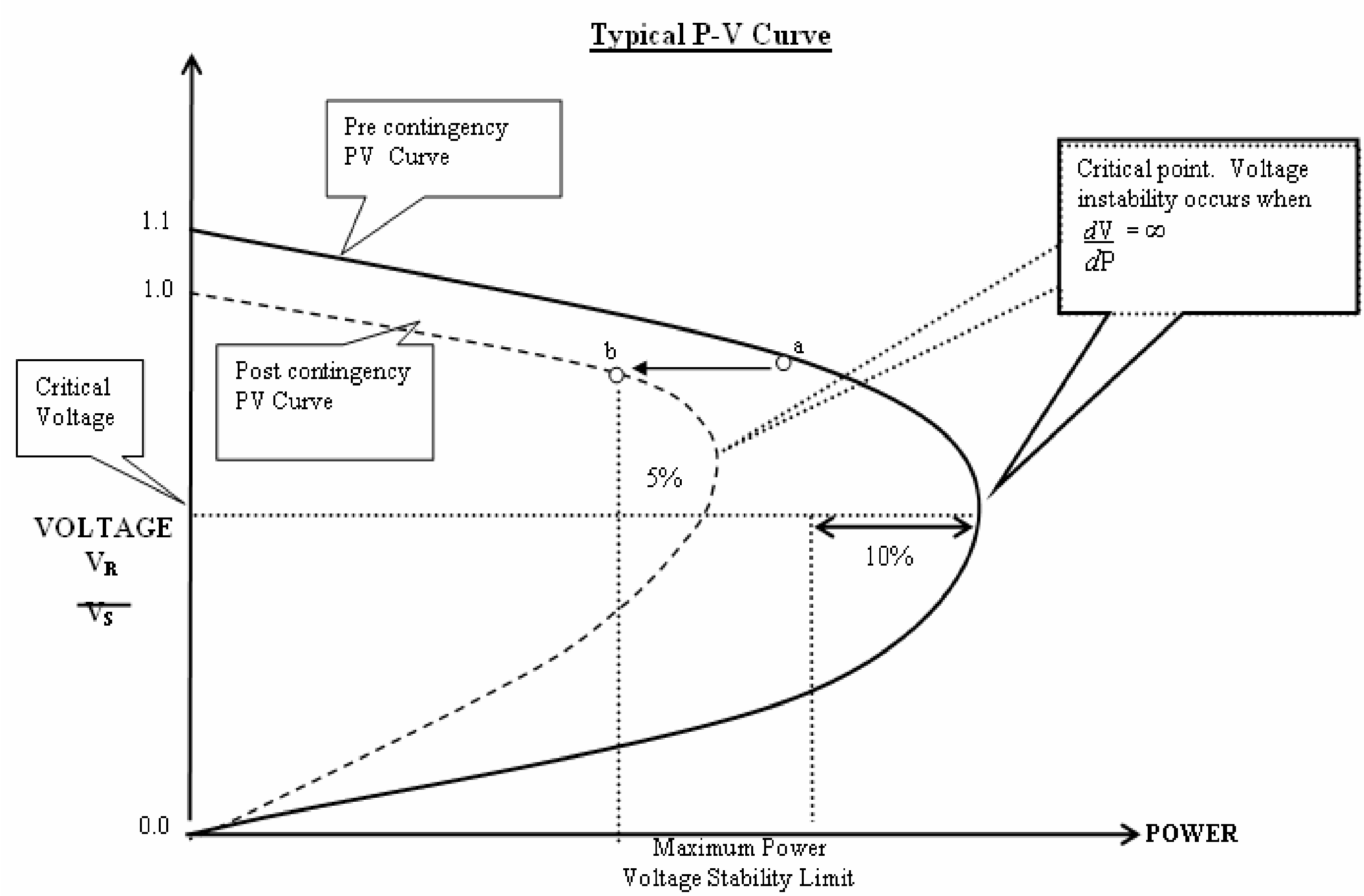
Power flow programs can be used to generate a P-V curve. In certain situations it may be desirable to manually generate a P-V curve to take into account specific remedies available.

A sample P-V curve is shown below. The critical point of the curve, or voltage instability point, is the point where the slope of the P-V curve is vertical. As illustrated, the maximum acceptable pre-contingency power transfer must be the lesser of:

- a pre-contingency power transfer (point a) that is 10% lower than the voltage instability point of the pre-contingency P-V curve, and

- a pre-contingency transfer that results in a post-contingency power flow (point b) that is 5% lower than the voltage instability point of the post-contingency curve

The P-V curve is dependent on the power factor. Care must be taken that the worst case P-V curve is used to identify the stability limit.



In addition, the change in the voltages that are experienced post-contingency are required to be within the limits specified in Clause 4.3 from the *Ontario Resource and Transmission Assessment Criteria* Document.

4.3 Voltage Change Limits

With all planned *facilities* in service pre-contingency, system voltage changes in the period immediately following a contingency are to be limited as follows:

Nominal Bus Voltage (kV)	**500kV**	**230kV**	**115kV**	**Transformer Station Voltages**		
				44kV	**27.6kV**	**13.8kV**
% voltage change **before** tap changer action	10%	10%	10%	10%	10%	10%
% voltage change **after** tap changer action	10%	10%	10%	5%	5%	5%
AND within the range						
Maximum* (kV)	550kV	250kV	127kV	112% of nominal		
Minimum* (kV)	470kV	207kV	108kV	88% of nominal		

* The maximum and minimum voltage ranges are applicable following a contingency. After the system is redispatched and generation and power flows are adjusted the system must return to within the maximum and minimum continuous voltages identified in section 4.2.

Before tap-changer action (immediate post-contingency period) a constant MVA load model can be used. If the voltage change exceeds the limits identified above, a voltage dependent load model should be used (e.g. $P \alpha V^{1.5}$, and $Q \alpha V^{2}$). After tap-charger action a constant power load model should be assumed (e.g. the load will return to its pre-contingency level). In areas of the system where it is known that post-contingency voltages will remain depressed after tap-changer and other automatic corrective actions, or in situations where special control actions are proposed (e.g., blocking of under-load tap-changers), the use of variable loads in the longer term post-contingency period may be acceptable.

In cases where voltage rises are a possibility (e.g., islanded generators), transient stability tests should be carried out as a check to ensure that realistic reactive additions are appropriate and that customer equipment will not be exposed to excessive voltages after the transient post-contingency period. The occurrence of a voltage rise for loss of a system element is rare but voltage rises after reclosure operations, especially where capacitor or reactor switching are involved, are relatively common and should be checked. Voltage rises should not result in bus voltages higher than the maximum values indicated in the above table. Not only is equipment damage a concern at such high voltages but, in addition, it may not be safe to carry out breaker switching operations to reduce the voltages to acceptable levels. Capacitor breakers at locations where excessive voltages are possible should be designed for appropriately higher operating voltages.

b) None of the contingency conditions examined are permitted to violate the voltage stability limits. Instead, the maximum transfer that could be accommodated by a transmission line or across a transmission Interface would be restricted to ensure that the limits in the voltage stability criteria are respected.

c) For the reason stated above, there are no known violations of the voltage stability criteria.

d) No voltage violations were determined in the analysis.

However, in order to determine the voltage stability limits for transfers across the FABC Interface, for each system reinforcement option, the corresponding pre- and post-contingency load flow studies were used. For each pre- and post-contingency condition, the output from the generating facilities at the Bruce Complex was gradually increased while a corresponding reduction was made in the combined output from the generating units at Darlington GS. This process continued until the "knee-points" of the PV-curves were obtained. These knee-points invariably manifest through a failure of the load flow analysis to converge.

Having obtained the PV-curves, the voltage stability limits are then determined by applying a margin of 10% to the pre-contingency condition, and a margin of 5% for the post-contingency condition.

e) Please refer to the letter from Hydro One to the Board dated March 13, 2008, at page 5, with respect to paragraph 3 of Procedural Order 5. To better utilize the resources available at the IESO and to obtain the maximum benefit from those resources, the IESO has proposed that it should perform a reasonable number of studies for Pollution Probe, at their specific direction. The results of these studies would then be provided to Pollution Probe in a format suitable for filing as evidence.

Pollution Probe INTERROGATORY #31 List 4

Interrogatory

Ref. Technical Attachment 1, which reflects an exchange of e-mails from 2006 between Jack Gibbons, Amir Shalaby (OPA VP of System Planning), and others.

Issue Number 1.0

1.0 Issue: Project Need and Justification

Request

The referenced e-mails from late 2006 discuss assumptions regarding the retirement dates for the Bruce B generating units. Has the OPA's forecast for these retirement dates changed since then? If yes, what is the current forecast?

Response

Yes, the OPA's forecast has changed since then. Please refer to the response to Energy Probe Interrogatory 6.

Pollution Probe INTERROGATORY #32 List 4

Interrogatory

Ref. Exh. B/T 6/S 5, Appendix 5
Issue Number 2.0
2.0 Issue: Project Alternatives

Request

On page 48 of Appendix 5, reference is made to reinforcing the London to Middleport or Nanticoke path by building a second 500 kV line along it.

a) Please describe whether this London alternative would provide for adding a double circuit 500 kV line, adding a single 500 kV line with one circuit, or some other configuration.

b) What would the London alternative cost compared to the proposed Bruce-Milton line? Please provide cost estimate workpapers.

c) What would the transfer capability away from Bruce be with the London alternative?

d) Please provide saved case(s) in PTI-format, compatible with Siemen's PSS/E version 30, for the load flow studies performed by or for Hydro One, the OPA, and/or the IESO in studying the London alternative.

Response

a) The London alternative referred to on page 48 of the IPSP Discussion Paper #5 assumes a double-circuit 500 kV from Bruce to Longwood and a single-circuit 500 kV line from Longwood to Middleport or Nanticoke. The "London" option under consideration in the current proceeding now assumes a double-circuit 500 kV between Longwood and Middleport rather than a single-circuit line.

b) Please refer to response to Board Staff Interrogatory 2.6 (iii).

c) Please refer to response to Board Staff Interrogatory 2.6 (i). Note that the transfer capability provided in the original response to Board Staff 2.6 (c) was incorrect. An updated response is provided.

d) Please refer to the letter from Hydro One to the Board dated March 13, 2008, at page 5, with respect to paragraph 3 of Procedural Order 5.

To better utilize the resources available at the IESO and to obtain the maximum benefit from those resources, the IESO has proposed that it should perform a reasonable number of studies for Pollution Probe, at its specific direction. The results of these studies would then be provided to Pollution Probe in a format suitable for filing as evidence.

Pollution Probe INTERROGATORY #33 List 4

Interrogatory

Ref. Exh. B/T 6/S 4 is the Ontario Reliability Outlook – March 2007. On page 3, it states: "Without new transmission facilities, the IESO will eventually be forced to operate existing facilities near their maximum capabilities, with little margin for unexpected events and requiring complex arrangements to do routine maintenance on critical facilities."

Issue Number 1.0
1.0 Issue: Project Need and Justification

Request

a) What are the critical facilities as far as the transmission facilities out of the Bruce complex are concerned?
b) What does routine maintenance include on 500 kV and on 230 kV transmission facilities?
c) How frequently is this maintenance typically performed?
d) Which of these routine maintenance items can be accomplished using liveline techniques on properly-designed facilities?
e) Please describe the types of "complex arrangements" that would be required in order to permit maintenance if the proposed transmission lines are not installed.
f) Please describe the live line maintenance that is performed to maintain 500 kV transmission lines and/or to maintain 230 kV transmission facilities in the Province.

Response

a) Critical facilities are usually defined to mean facilities whose status has an effect on an operating security limits. Generation dispatch, terminal voltage and demand also are critical. Transmission elements critical to Southern Ontario limits (including Bruce, Western and Middleport system elements) are as follows ("[#]" denotes the connectivity number):

500 kV Elements

Circuits		Buses	
B560V	[2]	Milton H-Bus Bus	[8]
B561M	[3]	Milton K-Bus	[47]
B562L	[4]	Bruce B P-Bus	[23]
B563L	[5]	Bruce B J-Bus	[24]

B569B	[6]
M570V	[7]
M571V	[8]
N582L	[10]
V586M	[11]
M585M	[12]
N580M or N581M	[13]
C550VP or C551VP	[14]

Bruce A A-Bus	[38]
Bruce A E-Bus	[39]

<u>Autotransformers</u>

Bruce T25 or T27	[17]
Bruce T28	[18]
Longwood T3, T4, T5, T6, T7	[20]
Middleport T3 or T6	[19]
Essa T3 or T4	[21]

<u>Breakers</u>

Bruce B H5P	[25]
Bruce B L563J	[26]
Bruce B L561P	[31]
Bruce B H6L561	[32]
Bruce B H6J	[33]
Bruce B H7P	[27]
Bruce B H7L569	[28]
Bruce B H8L569	[29]
Bruce B H8J	[30]
Bruce B H5L563	[50]

Bruce A T4A	[41]
Bruce A AL569	[48]
Bruce A T4L560	[48]
Bruce A EL569	[49]
Bruce A EL560	[42]
Bruce A AL562	[43]
Bruce A T28L562	[43]
Bruce A T3T28	[44]
Bruce A T3E	[45]
Longwood HL582	[22]
Middleport L81L85	[12]
Milton KL570	[9]
Middleport L80L86	[11]

230kV Elements

<u>Circuits</u>

B4V, B5V, B22D, B23D	[15]
M20D, M21D, D4W, D5W	[16]
E8V, E9V, D6V, D7V	[16]

<u>BUSES</u>

Bruce A K2-Bus	[34]
Bruce A D2-Bus	[40]
Bruce A K1-Bus (b)	[37]
Bruce A D1-Bus (b)	[46]

<u>Breakers</u>

Bruce A K2L27 (a)	[35]
Bruce A T2L27 (a)	[36]
Bruce A T2L5 (a)	[35]
Bruce A D2L5 (a)	[36]
Bruce A K1L22 (b)	[37]
Bruce A T1L22 (b)	[46]
Bruce A T1L20 (b)	[37]
Bruce A D1L20 (b)	[46]

Note: (a) above is critical if Bruce G2 is in-service, and (b) is critical if Bruce G1 is in-service.

<u>Additional Bruce System Elements</u>

B27S, Owen Sound T5, Essa-Hanover 115 kV Loop: S2E, S2S, S1H

<u>Central System</u>

230 kV Elements

<u>Circuits</u>

R14T, R17T, R19T, R21T
V71RP,V72R,V73R,V74R,V76R
C4R, C5R, P21R
P22R, C18R, C20R
B82V, M80B, B83V, M 81B***

<u>Breakers</u>

Brown Hill L80L82***
Brown Hill L81L83***

<u>Middleport System</u>

230 kV Elements

<u>Circuits</u>

T36B, T37B, T38B, T39B*
M27B, M28B
B18H, B20H
M34H
N1M, N2M, N5M, N6M
Q30M, Q23BM, Q25BM
Q24HM, Q29HM
PA27, BP76**
PA301, PA302**

<u>Western System</u>

230kV Elements

<u>Circuits</u>

M31W, M 32W, M33W
N21W, N22W * Impacts only FETT
L23N, L25N, L27N ** Impacts only BRUCE Sys tem
L24L, L26L *** Impacts only CLAN/CLAS
L28C, L29C
W42L, W43L
W44LC, W45LC
C21J, C22J
L4D, L51D, J5D
B3N critical to BLIP/NBLIP only during the summer months

<u>FETT</u> (Central and Middleport Sys tem Elements also impact Limits)

500 kV Elements

<u>Circuits</u>

B560V or B561M	[2]
B562L or B563L	[3]
V586M	[4]
M585M	[5]
N580M	[6]
N581M	[7]
M570V	[8]
M571V	[9]
M572T or M573T [11]	
C550VP (& Parkway T4)	[13]
or C551VP (& Parkway T3)	
N582L	[14]
E510V or E511V	[15]

<u>Buses</u>

Milton H Bus	[9]
Milton K Bus	[10]

<u>Autotransformers</u>

Trafalgar T14 or T15	[11]
Claireville T13,T14,T15,T16	[12]
or Parkway T3 or T4	

<u>Breakers</u>

Middleport L80L86	[4]
Middleport L81L85	[5]
Milton KL561	[9]

b) "Routine maintenance", as expressed in the above includes cyclical maintenance, asset condition assessments and defect corrections.

The cyclical activities include foot patrol, helicopter patrol, thermovision patrols, insulator washing, climbing inspections and switch maintenance.

Asset condition assessments are scheduled based on the observed condition of the assets during patrols and other maintenance activities, as well as reliability trends. These include tower corrosion assessments, insulator testing, shieldwire and conductor sampling, and 230 kV wood poles and foundation assessments.

Corrective work includes repairs such as damaged and corroded tower members, tower coating, replacement of defective insulators and fittings, and conductor, switch, damper and foundation repairs.

c) The cyclical maintenance is scheduled as follows:

- Foot Patrol: once every 5 years.
- Helicopter Patrol: every year.

- Thermovision Patrol: generally every 3 years except critical lines. These are patrolled on an annual basis.

- Switch maintenance: every 5 years

Asset condition assessment activities to a large part are dependent on the aging of the assets.

Defects identified during cyclical maintenance and asset condition assessments are corrected as required.

d) Activities that can be completed while a line is energized include: patrols, insulator washing (except 500 kV), climbing inspection, corrosion assessments, insulator testing, climbing inspections, shieldwire sampling and foundation assessments.

Those activities that require personnel to come within prescribed distances of energized conductors require special work procedures, e.g., insulator testing, insulator washing, climbing inspections and shieldwire sampling.

In terms of corrective work, live-line insulator replacement can be carried out on some structures, but current approved work methods are not suitable for all structure types as clearances are not adequate to carry out the work in a safe manner on a live-line basis. Damper repairs and other minor repairs can be done “bare hand,” but to make these repairs requires costly vehicles equipped with an insulated boom.

e) It is expected that as the system utilization increases, Hydro One will be requested to keep lines and other facilities in service while carrying out maintenance, thereby requiring the development of complex and special work procedures.

Activities that normally require an outage that might be done using special arrangements include: insulator changes on 500 kV towers and 230 kV dead-end and angle towers, removing conductor samples for testing, switch maintenance, and corrective work on conductors, shieldwires, dampers, energized fittings and structural supports.

In many cases special procedures would need to be developed and these would increase safety risks to workers and require longer periods for repair. In some situations a suitably safe solution may not be possible. Acceptable solutions may involve installing temporary insulator strings to isolate the damaged line section and installing a bypass to facilitate repairs. For tower coating, a solution would involve installing protection above the conductor to prevent dripping paint from providing a path for an arc to flashover to the structure. With 230 kV wood structures, there would be a need to install a full structure live line in order to replace a defective arm, as in most cases a deteriorated arm cannot be replaced safely under energized conditions.

All of the above-noted complex procedures would be more costly than repairs made during an outage, increase safety risks to workers, and require an increase in the number of trained staff and costly equipment.

f) Live line maintenance is used to test insulators from a helicopter platform or from a tower. Insulator washing is carried out live line except on 500 kV lines. Climbing inspections are also completed live line. As well, on suspension structures, insulators can generally be replaced under live conditions if the insulator string is in a condition where the work can be carried out safely (i.e., the number of defective units in a string below a prescribed limit that will allow staff to approach the string without fear of flashover).

Pollution Probe INTERROGATORY #34 List 4

Interrogatory

Ref. Exh. B/T 6/S 4 is the Ontario Reliability Outlook – March 2007. On page 3, it states: "Without new transmission facilities, the IESO will eventually be forced to operate existing facilities near their maximum capabilities, with little margin for unexpected events and requiring complex arrangements to do routine maintenance on critical facilities."

Issue Number 1.0

1.0 Issue: Project Need and Justification

Request

For the double circuit 500 kV transmission lines in the Province:

a) Please provide the sustained outage rate per kilometer per year for overhead transmission circuits.

b) Please provide a breakdown of the causes of sustained outages for overhead transmission lines.

c) Please provide the average restoration time for overhead transmission lines experiencing a sustained outage.

d) Please provide the momentary outage rate per kilometer per year for overhead transmission circuits.

e) Please provide a breakdown of the causes of momentary outages for overhead transmission lines.

f) Please provide the definitions of sustained outage and momentary outage used in the data supplied in response to the above.

g) What percentage of the sustained outages affecting a 500 kV transmission circuit on a double circuit transmission line causes both circuits on the line to experience sustained outages?

h) What percentage of the momentary outages affecting a 500 kV transmission circuit on a double circuit transmission line causes both circuits on the line to experience momentary outages?

Response

a) Sustained outage rate = .00100821 outages /year/km

Assumptions:

- Outage data covers the period Jan 1990 to Jan 2007
- Common mode outages are included in the assessment

- Outages related to line terminals are excluded
- All outages regardless of their durations are included.

b) The Table below gives the causes of sustained outages to 500 kV circuits on double circuit tower lines from January 1990 to January 2007.

Cause	Number of Outages	% of Total
Terminal equipment defects	48	33.3%
Protection equipment defects	43	29.9%
Line equipment failures – eg. Conductor, insulators or tower	18	12.5%
Maintenance personnel	15	10.4%
Adverse weather (Lightning, Wind, Ice etc.)	14	9.7%
Public – eg tree contact, gunfire	1	0.7%
Forest Fire	1	0.7%
Unknown	4	2.8%
Total Sustained Outages	144	

c) Average restoration time = 38.58285 hour/outage

Assumptions:

- Outage data covers the period Jan 1990 to Jan 2007
- Common mode outages are included in the assessment
- Outages related to line terminals are excluded
- All outages regardless of their durations are included.

d) Momentary outage rate = .00175624 outages/year/km

The same assumptions as above

e) The Table below gives the causes of momentary outages to 500 kV circuits on double circuit tower lines from January 1990 to January 2007.

Cause	Number of Outages	% of Total
Adverse weather – Isolated lightning	22	25.3%
Adverse weather – Severe electrical storm	14	16.1%
Other Adverse weather (Wind, Ice, fog etc.)	13	15.0%
Protection equipment defects	11	12.6%
Maintenance personnel	4	4.6%
Line equipment failures – eg. Conductor, insulators or tower	2	2.3%
Terminal equipment defects	1	1.1%
Unknown	20	23.0%
Total Momentary Outages	87	

f) Momentary or transient line outage is an outage that lasts less than one minute and the line is removed from service and is returned to service by the line protection system (This covers only automatic re-closure events).

Sustained or permanent line outage is an outage that lasts one minute or more and the line is removed from service either automatically (by the protection system) or manually (It does not include automatic re-closure events).

g) The answer to this question is not readily available.

h) The answer to this question is not readily available.

Pollution Probe INTERROGATORY #35 List 4

Interrogatory

Ref. Exh. B/T 6/S 4 is the Ontario Reliability Outlook – March 2007. On page 3, it states: "Without new transmission facilities, the IESO will eventually be forced to operate existing facilities near their maximum capabilities, with little margin for unexpected events and requiring complex arrangements to do routine maintenance on critical facilities."

Issue Number 1.0

1.0 Issue: Project Need and Justification

Request

For all the 500 kV transmission lines in the Province:

a) Please provide the sustained outage rate per kilometer per year for overhead transmission circuits.
b) Please provide a breakdown of the causes of sustained outages for overhead transmission lines.
c) Please provide the average restoration time for overhead transmission lines experiencing a sustained outage.
d) Please provide the momentary outage rate per kilometer per year for overhead transmission circuits.
e) Please provide a breakdown of the causes of momentary outages for overhead transmission lines.
f) Please provide the definitions of sustained outage and momentary outage used in the data supplied in response to the above.

Response

a) Sustained outage rate = .0012634 outages/year/km

Assumptions:

- Outage data covers the period Jan 1990 to Jan 2007
- Common mode outages are included in the assessment
- Outages related to line terminals are excluded
- All outages regardless of their durations are included.

b) The Table below gives the causes of sustained outages to 500 kV circuits from January 1990 to January 2007.

Cause	Number of Outages	% of Total
Protection equipment defects	70	28.2%
Terminal equipment defects	61	24.6%
Line equipment failures – eg. Conductor, insulators or tower	40	16.1%
Maintenance personnel	37	14.9%
Adverse weather (Lightning, Wind, Ice etc.)	27	10.9%
Unknown	7	2.8%
Public – eg gunfire	5	2.0%
Forest Fire	1	0.4%
Total Sustained Outages	248	

c) Average restoration time = 42.56232 hour/outage

Assumptions:

- Outage data covers the period Jan 1990 to Jan 2007
- Common mode outages are included in the assessment
- Outages related to line terminals are excluded
- All outages regardless of their durations are included.

d) Momentary outage rate = .00131393 outages/year/km

Assumptions:

- Outage data covers the period Jan 1990 to Jan 2007
- Common mode outages are included in the assessment
- Outages related to line terminals are excluded
- All outages regardless of their durations are included.

e) The Table below gives the causes of momentary outages to 500 kV circuits from January 1990 to January 2007.

Cause	Number of Outages	% of Total
Adverse weather – Isolated lightning	28	26.7%
Adverse weather – Severe electrical storm	18	17.1%
Other Adverse weather (Wind, Ice, fog etc.)	14	13.3%
Protection equipment defects	13	12.4%
Maintenance personnel	6	5.7%
Line equipment failures – eg. Conductor, insulators or tower	4	3.8%
Terminal equipment defects	1	1.0%
Unknown	21	20.0%
Total Momentary Outages	105	

f) Momentary or transient line outage is an outage that lasts less than one minute and the line is removed from service and is returned to service by the line protection system (This covers only automatic re-closure events).

Sustained or permanent line outage is an outage that lasts one minute or more and the line is removed from service either automatically (by the protection system) or manually (It does not include automatic re-closure events).

Pollution Probe INTERROGATORY #36 List 4

Interrogatory

Ref. Exh. B/T 6/S 4 is the Ontario Reliability Outlook – March 2007. On page 3, it states: "Without new transmission facilities, the IESO will eventually be forced to operate existing facilities near their maximum capabilities, with little margin for unexpected events and requiring complex arrangements to do routine maintenance on critical facilities."

Issue Number 1.0

1.0 Issue: Project Need and Justification

Request

For the double circuit 230 kV transmission lines in the Province:

a) Please provide the sustained outage rate per kilometer per year for overhead transmission circuits.
b) Please provide a breakdown of the causes of sustained outages for overhead transmission lines.
c) Please provide the average restoration time for overhead transmission lines experiencing a sustained outage.
d) Please provide the momentary outage rate per kilometer per year for overhead transmission circuits.
e) Please provide a breakdown of the causes of momentary outages for overhead transmission lines.
f) Please provide the definitions of sustained outage and momentary outage used in the data supplied in response to the above.
g) What percentage of the sustained outages affecting a 230 kV transmission circuit on a double circuit transmission line causes both circuits on the line to experience sustained outages?
h) What percentage of the momentary outages affecting a 230 kV transmission circuit on a double circuit transmission line causes both circuits on the line to experience momentary outages?

Response

a) Sustained outage rate = .00362875 outages/year/km

Assumptions:
- Outage data covers the period Jan 1990 to Jan 2007
- Common mode outages are included in the assessment

- Outages related to line terminals are excluded
- All outages regardless of their durations are included.

b) The causes will be similar to those provided for Pollution Probe Interrogatory No. 37.

c) Average restoration time = 53.01006 hours/outage

Assumptions:

- Outage data covers the period Jan 1990 to Jan 2007
- Common mode outages are included in the assessment
- Outages related to line terminals are excluded
- All outages regardless of their durations are included.

d) Momentary outage rate = .0067756 outages/year/km

Assumptions:

- Outage data covers the period Jan 1990 to Jan 2007
- Common mode outages are included in the assessment
- Outages related to line terminals are excluded
- All outages regardless of their durations are included.

e) The causes will be similar to those provided for Pollution Probe Interrogatory No. 37.

f) Momentary or transient line outage is an outage that lasts less than one minute and the line is removed from service and is returned to service by the line protection system (This covers only automatic re-closure events).

Sustained or permanent line outage is an outage that lasts one minute or more and the line is removed from service either automatically (by the protection system) or manually (It does not include automatic re-closure events).

g) The answer to this question requires is not readily available.

h) The answer to this question requires is not readily available.

Pollution Probe INTERROGATORY #37 List 4

Interrogatory

Ref. Exh. B/T 6/S 4 is the Ontario Reliability Outlook – March 2007. On page 3, it states: "Without new transmission facilities, the IESO will eventually be forced to operate existing facilities near their maximum capabilities, with little margin for unexpected events and requiring complex arrangements to do routine maintenance on critical facilities."

Issue Number 1.0
1.0 Issue: Project Need and Justification

Request

For all the 230 kV transmission lines in the Province:

a) Please provide the sustained outage rate per kilometer per year for overhead transmission circuits.
b) Please provide a breakdown of the causes of sustained outages for overhead transmission lines.
c) Please provide the average restoration time for overhead transmission lines experiencing a sustained outage.
d) Please provide the momentary outage rate per kilometer per year for overhead transmission circuits.
e) Please provide a breakdown of the causes of momentary outages for overhead transmission lines.
f) Please provide the definitions of sustained outage and momentary outage used in the data supplied in response to the above.

Response

a) Sustained outage rate = .00386797 outages/year/km

Assumptions:
- Outage data covers the period Jan 1990 to Jan 2007
- Common mode outages are included in the assessment
- Outages related to line terminals are excluded
- All outages regardless of their durations are included.

b) The Table below gives the causes of sustained outages to 230 kV circuits from January 1990 to January 2007.

Cause	Number of Outages	% of Total
Adverse weather – Isolated lightning	270	11.9%
Adverse weather – Severe electrical storm	187	8.3%
Other Adverse weather (Wind, Ice, fog etc.)	123	5.4%
Protection equipment defects	808	35.8%
Terminal equipment defects	361	16.0%
Line equipment failures – eg. Conductor, insulators or tower	265	11.7%
Maintenance personnel	137	6.1%
Public – eg tree contact, gunfire	36	1.6%
Forest Fire or other adverse environment	8	0.4%
Unknown	65	2.9%
Total Sustained Outages	2260	

c) Average restoration time = 46.16345 hour/outage

Assumptions:

- Outage data covers the period Jan 1990 to Jan 2007
- Common mode outages are included in the assessment
- Outages related to line terminals are excluded
- All outages regardless of their durations are included.

d) Momentary outage rate = .00674586 outages/year/km

Assumptions:

- Outage data covers the period Jan 1990 to Jan 2007
- Common mode outages are included in the assessment
- Outages related to line terminals are excluded
- All outages regardless of their durations are included.

e) The Table below gives the causes of momentary outages to 230 kV transmission circuits from January 1990 to January 2007.

Cause	Number of Outages	% of Total
Adverse weather – Isolated lightning	744	36.8%
Adverse weather – Severe electrical storm	551	27.2%
Other Adverse weather (Wind, Ice, fog etc.)	181	8.9%
Protection equipment defects	215	10.6%
Maintenance personnel	93	4.6%
Line equipment failures – eg. Conductor, insulators or tower	24	1.2%
Terminal equipment defects	13	0.6%

Public – eg tree contact, gunfire	9	0.4%
Forest Fire or other adverse environment	9	0.4%
Unknown	184	9.1%
Total Momenatry Outages	2023	

f) Momentary or transient line outage is an outage that lasts less than one minute and the line is removed from service and is returned to service by the line protection system (This covers only automatic re-closure events).

Sustained or permanent line outage is an outage that lasts one minute or more and the line is removed from service either automatically (by the protection system) or manually (It does not include automatic re-closure events).

Pollution Probe INTERROGATORY #38 List 4

Interrogatory

Ref. Exh. B/T 6/S 5 Appendix 6 is Discussion Paper 7 Integrating the Elements. On Page 39 is a bar graph of the MW of installed nuclear capacity for each year from 2007 through 2027.

Issue Number 1.0

1.0 Issue: Project Need and Justification

Request

For each year from 2007 through 2027, please provide the total nuclear capacity in MW and a breakdown of that capacity by nuclear unit, along with a description of whether such unit is considered to "existing", "refurbished", or "new".

Response

Hydro One has declined to respond to this interrogatory. Please refer to correspondence on behalf of Hydro One dated March 13, 2008 to the Board.

Pollution Probe INTERROGATORY #39 List 4

Interrogatory

Ref. Technical Conference Panel One (Oct 15, 2007) slide presentation, slide 31 of 43.

Issue Number 2.0
2.0 Issue: Project Alternatives

Request

The slide shows eight options considered, including the proposed transmission line from Bruce to Milton, and five screening categories:

a) For each of the options listed, please provide a description of the facilities included in each option.
b) For each of the options listed, please provide a description of the total transmission capability in MW away from Bruce with no contingencies.
c) For each of the options listed, please provide a description of the total transmission capability in MW away from Bruce with the worst single contingency, and a description of that contingency.
d) For the capacity determinations addressed in (b) and (c) above, please describe and provide the assumptions for generation dispatch and system imports that were used in these determinations.
e) For each of the options listed, please describe the effects on other transmission paths that were considered.
f) For each of the options listed, please provide total cost for the option, a cost breakdown for the option, and cost workpapers.
g) For each of the options listed, please describe the land use characteristics that were considered.

Response

a) Descriptions of the facilities comprising each option above, other than series compensation, are presented in the application (Exhibit B Tab 3 Schedule 1 at pages 4-6). Series compensation was described during the Technical Conference (please refer to the Day 1 transcript at page 26). Generally, series compensation on the three 500kV circuits between Longwood and Nanticoke, and Bruce to Longwood would include facilities situated at the midpoint of those facilities at a new station site. The facilities would comprise an insulated platform, capacitor banks, protective equipment, switches and breakers.

b) Assuming no contingencies, the total transmission capabilities of all options considered are greater than those tabulated in response c) below. For planning and operating purposes, the Bruce transmission system is tested for the loss of a double circuit line, as is required by NPCC and IESO planning and reliability standards. It is therefore inappropriate to consider capability with a "no contingencies" assumption.

c) The total transmission capabilities in MW for the options considered as well as the limiting contingencies are shown in the table below. The options involving HVDC connections have not been studied by the IESO, but the IESO is unaware of any technical reason that HVDC connections could not increase transfer capability to the level required, assuming that the necessary facilities are constructed.

d) For each of the options studied by the IESO, the assumptions for generation dispatch and system imports are tabulated below.

e) For each of the options studied by the IESO, voltage stability, transient stability and thermal effects were considered. The voltage stability effects were found to be the most limiting.

f) **Series Capacitors on 500 kV line**

- Two new station sites on existing transmission corridor
- Three new 500 kV series capacitor installations along with protective equipment and 500 kV bypass breakers
- Changes to existing circuit protections
- $97M

Bruce x Essa 500 kV line

- A 187 km 500 kV 2-circuit transmission line from Bruce GS to Essa TS
- Circuit termination equipment at each of Bruce A TS, Bruce B SS, and Essa TS for two circuits along with new 500 kV circuit breakers
- New teleprotection equipment to protect the new circuits
- $635M – Essentially the same as the Bruce x Milton alternative

Bruce x Longwood x Middleport 500 kV line

- A 187 km 500 kV 2-circuit transmission line from Bruce GS to Longwood TS
- A 150 km 500 kV 2-circuit transmission line from Longwood TS to Middleport TS.
- Circuit termination equipment at each of Bruce A TS, Bruce B SS, Longwood TS for three circuits and Middleport TS along with new 500 kV circuit breakers at each location
- New teleprotection equipment to protect the new circuits
- $1,070M ($3 M/km + $20M per circuit termination)

HVDC Lite Cable(s) from Bruce to Milton

- Underground cable(s) with sufficient capacity for 3000 MW between Bruce and Milton (176 km)
- HVDC lite converter stations at both Bruce x Milton sufficient for 3000 MW capacity complete with transformers. Since current technology support 500 MW per pair, six pairs of converter stations and 6 sets of underground cable circuits would be required
- 500 kV termination equipment at Bruce A TS, Bruce B SS and Milton SS suitable for 6 sets of converter pairs
- New teleprotection equipment to protect the new equipment
- $1.5 - $2.0 billion

HVDC 500 kV line from Bruce x Milton

- A 176 km 450 kV HVDC bipolar transmission line from Bruce B SS to Milton SS
- HVDC converter equipment located at both Bruce B SS and Milton SS with 3000 MW capacity complete with transformers and filters
- 500 kV termination equipment at Bruce B SS for two new positions and Milton SS for two positions
- New teleprotection equipment to protect the new equipment
- $1.5 - $2.0 billion

Bruce x Kleinburg x Claireville 500 kV line

- A 189 500 kV 2-circuit transmission line from Bruce GS to Kleinburg TS including approximately 50 km of new right-of-way from approximately Colebeck Junction to a location near Schomberg Ontario
- Circuit termination equipment at each of Bruce A TS, Bruce B SS, and Kleinburg TS for two circuits along with new 500 kV circuit breakers
- Two new 500/203 kV 750 MVA autotransformers at Kleinburg TS
- Four new 230 kV circuit terminations at Kleinburg TS
- A new 5 km long 230 kV 2 circuit line from Kleinburg TS to the existing B82V/B83V 230 kV line near Kleinburg
- New teleprotection equipment to protect the new circuits

- $750M ($3 M/km + $20M per circuit termination +$100 M for modifications to Kleinburg TS)

Bruce x Crieff 500 kV line

- The establishment of a new 500/230 kV TS, Crieff TS south of Guelph near the Highway 401 and Highway 6 interchange with two 500/230 kV autotransformers and a 20 km two circuit 20 kV line from Crieff TS to Preston TS
- A 150 500 kV 2-circuit transmission line from Bruce GS to Crieff TS following the existing Bruce x Milton right-of-way to Hanover TS, the Hanover TS to Detweiler 115 kV right-of-way (D10H) and a new approx 30 km right-of-way from north of Guelph to Crieff TS
- Circuit termination equipment at each of Bruce A TS, Bruce B SS, and Crieff TS for two circuits along with new 500 kV circuit breakers
- New teleprotection equipment to protect the new circuits
- $700M ($3 M/km + $20M per circuit termination +$100 M to establish Crieff TS + $20M property + $50M for new line to Preston TS)

Bruce x Milton 500 kV line

- A 176 km 500 kV 2-circuit transmission line from Bruce GS to Milton SS
- Circuit termination equipment at each of Bruce A TS, Bruce B SS, and Milton SS for two circuits along with new 500 kV circuit breakers
- New teleprotection equipment to protect the new circuits
- $635M

g) The land use characteristics of the transmission options listed in slide 31 of 43 (Technical Conference Panel One presentation, October 15, 2007) are similar in that all of the options traverse or occupy primarily rural and agricultural lands.

Five options (Bruce to Milton, Bruce to Essa, Bruce to Longwood to Middleport, HVDC, HVDC-lite) would be situated on an existing transmission corridor or a widened existing transmission corridor. These options are consistent with the 2005 Provincial Policy Statement (Exhibit B, Tab 6, Schedule 5, Appendix 13).

Two options (Bruce to Kleinburg, Bruce to Crieff) would be situated in part on a widened existing corridor and in part on a new or “greenfield” transmission corridor. The series capacitors option would likely be situated on rural or agricultural lands close to and possibly abutting existing transmission corridors.

h) The losses on the existing system are approximately 1355 MW with 8 Bruce units in service (per diagram 4 of the SIA). The losses for each of the alternatives are tabulated below.

	Bruce to Milton 500 kV line
No contingency	Not limiting
Capability with worst contingency	8160 MW
Worst single contingency	Loss of Bruce x Milton/Claireville circuits
Generation dispatch	- 8 Bruce units - 725 MW Committed Bruce area wind generation - 4 Lambton units - No Nanticoke
System imports	1500 MW from Michigan
System Losses	1239 MW

	Series Capacitors on 500 kV lines	Bruce to Essa 500 kV line	Bruce to Longwood to Middleport 500 kV line	Bruce to Kleinburg to Claireville 500 kV line	Bruce to Crieff TS 500 kV line
No contingency	Not limiting	Not limiting	Not limiting	Not limiting	Not limiting
Capability with worst contingency with respect to the Bruce to Milton 500 kV alternative	Δ -1834 MW*	Δ -1196 MW	Δ -1139 MW	Δ -29 MW	Δ –656 MW
Worst single contingency	Loss of Bruce x Milton/Claireville circuits	Loss of Bruce x Milton/Claireville circuits	Loss of Bruce x Milton/Claireville circuits	Loss of Bruce x Milton/Claireville circuits	Loss of both Crieff x Milton/Claireville circuits
Generation dispatch	- 7 Bruce units - 725 MW wind - No Lambton - No Nanticoke	- 8 Bruce units - 725 MW wind - 4 Lambton units - No Nanticoke	- 8 Bruce units - 725 MW wind - 4 Lambton units - No Nanticoke	- 8 Bruce units - 725 MW wind - 4 Lambton units - No Nanticoke	- 8 Bruce units - 725 MW wind - 4 Lambton units - No Nanticoke
System imports	1500 MW from Michigan	1500 MW from Michigan	1500 MW from Michigan	1500 MW from Michigan	1500 MW from Michigan
System Losses	795 MW*/ 1368MW	1277 MW	1283 MW	1238 MW	1242 MW
* Study conditions for this option are different than those studied for the alternatives to the Bruce to Milton 500 kV line.					

Pollution Probe INTERROGATORY #40 List 4

Interrogatory

Ref. Technical Conference Panel One (Oct 15, 2007) slide presentation, slide 38 of 43

Issue Number 2.0
2.0 Issue: Project Alternatives

Request

The slide addresses near-term measures to add transmission capacity.

a) Please provide a description of the facilities included in each measure.
b) Please provide a description of the cost of each of the facilities included in each measure, a cost breakdown, and cost workpapers.
c) Please provide a description of the increase in system capacity that each installation provides.
d) Please provide the capacity of the transmission system away from Bruce with these measures installed on the existing system with no contingencies, and without these measures installed with no contingencies.
e) Please provide the capacity of the transmission system away from Bruce with these measures installed on the existing system with the worst single contingency, and provide a description of that contingency.

Response

a) & b)

1) **Hanover to Orangeville line upgrade -** the Hanover TS to Orangeville TS section of B4V/B5V, approximately 77km in length, is to be uprated from the existing sag temperature of 104°C to 127°C. The upgrade will be achieved by re-tensioning the conductor throughout the entire 77 km line section, reinforcing 31 towers, and moving the bottom phase conductor to middle extension arm at seven towers. The estimated cost is $4.3 million. Please see attachement 1 included in the response to Pollution Probe Interrogatory 45 for the details of the cost estimate.

2) **New Shunt capacitor Banks** - nine new shunt capacitor banks are to be installed as follows:

Location	Designation	Capacity	Voltage Rating	Cost
Detweiler TS	SC22	245 MVAr	250 kV	$5.3M
Orangeville TS	SC21	245 MVAr	250 kV	$6.2M
Buchanan TS	SC23	200 MVAr	250 kV	Note 1
Middleport TS	SC21	250 MVAr	250 kV	Note 1
Middleport TS	SC22	250 MVAr	250 kV	Note 1
Middleport TS	SC23	250 MVAr	250 kV	Note 1
Middleport TS	SC24	250 MVAr	250 kV	Note 1
Nanticoke TS	SC21	250 MVAr	250 kV	Note 1
Nanticoke TS	SC22	250 MVAr	250 kV	Note 1

Note 1) The cost estimates for these facilities are under development

3) **Static Var Compensators** - project development work is still ongoing regarding the proposed static Var compensators to be installed at Detweiler TS and Nanticoke TS. Technical details regarding the configuration have yet to be finalized. Cost estimates will be developed after the technical specifications have been completed.

c) The capability increase amount has not been determined for each facility.

d) The capability consideration without contingency is not applicable, as by definition, the capability determination must satisfy all applicable planning criteria which include the worst recognized contingency.

e) Please refer to the response to Pollution Probe Interrogatory 16.

Pollution Probe INTERROGATORY #41List 4

Interrogatory

Ref. Technical Conference Panel One (Oct 15, 2007) slide presentation, slide 40 of 43.

Issue Number 2.0
2.0 Issue: Project Alternatives

Request

This slide addresses interim measures to add transmission capacity.

a) Please provide a description of the facilities included in each measure.
b) Please provide a description of the cost of each of the facilities included in each measure, a cost breakdown, and cost workpapers.
c) Please provide a description of the increase in system capacity that each installation provides.
d) Please provide the capacity of the transmission system away from Bruce with these measures installed on the existing system with no contingencies, and without these measures installed with no contingencies (assume that near-term measures described in Interrogatory 36 are in service).
e) Please provide the capacity of the transmission system away from Bruce with these measures installed on the existing system with the worst single contingency, and provide a description of that contingency.
f) The slide states that the installation of series capacitors is still under consideration. Please describe what progress has been made on such consideration since last October and provide a copy of any study results, analyses, reports, etc. that are available as a result.
g) The slide states that the installation of series capacitors requires extensive changes to the Bruce transmission system. Please describe these expensive changes and provide a copy of any analyses, reports, etc. that address these changes.

Response

a) There are no facilities related to the Orange Zone because it represents a moratorium on new generation connections to the transmission system.

Expanding of the coverage of the Bruce Special Protection Scheme (BSPS) entails adding new computerized inputs and outputs to enable the detection of new critical transmission contingencies, to enable the rejection of transmission connected windfarms within the Bruce area, and to enable the cross-tripping of a circuit breaker at Stayner TS to avoid post-contingency circuit overload of the Owen Sound to Stayner 115 kV transmission circuit (S2S). This would also reactivate certain load rejection stations in southwestern Ontario that were deactivated after the shutdown of the Bruce A generating units G1, G2, G3 and G4 in 1997.

Please see the response to Pollution Probe Interrogatory 39 in respect of series compensation.

b) The BSPS expansion would cost $7.2 million, and series compensation would cost $97 million.
c) Please refer to Table 1 in the response to Pollution Probe Interrogatory 16.
d) The capability consideration without contingency is not applicable. Please refer to the response to Pollution Probe Interrogatory 39(b).
e) c) Please refer to Table 1 in the response to Pollution Probe Interrogatory 16. In all cases, the worst contingency is the loss of Bruce to Milton/Claireville circuits.
f) The due diligence study filed in response to Pappas Interrogatory 6 has been under review. As noted in that response, no further decisions have been taken. Please refer to the response to Board Staff Interrogatory 2.2.1
g) Please refer to the response to Pappas Interrogatory 6. More detailed engineering studies will be required to determine the extent of the changes. For example, changes will be required to the relaying and protection systems for the critical 230 and 500 kV circuits in the Bruce transmission systems. Preliminary cost estimates for series capacitors are shown in Table 1 in the response to Pollution Probe Interrogatory 16.

Pollution Probe INTERROGATORY #42 List 4

Interrogatory

Ref. Exh. B/T 1/S 1. On page 2, Table 1 lists generation resources, loads, and interconnection capacities in SW Ontario.

Issue Number 1.0

1.0 Issue: Project Need and Justification

Request

a) For each of the generation resources listed, please provide:

- i the name of each generating unit that is included in each generation resource listed;
- ii each generating unit's in-service date;
- iii each generating unit's projected shut-down date (if any);
- iv each generating unit's summer peak generating capacity;
- v each generating unit's winter peak generating capacity;
- vi each generating unit's minimum generating level
- vii each generating unit's primary fuel;
- viii each generating unit's net generation in each of the last three years; and
- ix each generating unit's per-MWH fuel and variable operating cost in each of the last three years.

b) For each of the loads listed, please provide the summer peak load and the winter peak load in each of the past three years, and please also provide the annual energy consumed by each of the loads in each of the past three years.

c) For each of the interconnections listed:

- i please provide net summer MW and MWH supplied over the interconnection and the direction of the net supply;
- ii please provide net winter MW and MWH supplied over the interconnection and the direction of the net supply; and
- iii please explain how winter and summer are defined.

d) What level of generation reserve margin is considered adequate to provide reliable supply in the Province?

e) Please provide a copy of any planning criteria used in the Province to plan for reliable electric generation supply.

Response

a) Hydro One has declined to respond to this Interrogatory. Please refer to correspondence sent on behalf of Hydro One dated March 13, 2008.

b) The winter and summer peak loads for the areas requested are shown in the table below. The loads in referenced table (Exhibit B Tab 1 Schedule 1 page 2 Table 1) are rounded, whereas the loads in the table below are more precise.

Loads (MW)	2005		2006		2007	
	Winter	Summer	Winter	Summer	Winter	Summer
Windsor	800	1075	727	1044	770	893
Sarnia	731	823	723	785	724	754
London	573	749	607	756	595	651
KWCG	1229	1392	1182	1383	1226	1301
Hamilton	1090	1229	1032	1291	1087	1184
Woodstock/Ingersoll	155	170	163	180	165	170
Brantford/Brant	221	261	181	213	181	202
Niagara	846	1042	915	1087	863	1058
Other	2085	2052	1765	2229	2148	2183
Total	7729	8794	7295	8969	7760	8396

The annual energy consumed by each of the loads in each of the past three years are as follows:

Load	**Annual Energy Consumption (MWh)**		
	2005	**2006**	**2007**
Windsor	5038584	5028525	5020465
Sarnia	5134394	5124143	5115931
London	3762345	3754834	3748816
KWCG	7428122	7413293	7401411
Hamilton	7430382	7415548	7403662
Woodstock/Ingersol	1057867	1055755	1054063
Brandford/Brant	1124308	1122064	1120265
Niagara	5752611	5741126	5731924
Other	15516186	15485208	15460389
Total	**52244800**	**52140495**	**52056926**

c)

Michigan Interface		
	Net Scheduled Interchange	
Period	**(MWh)**	**(MW)**
Winter (2004–2005)	-1,748,818	-1,980
Summer (2005)	-1,478,459	-1,646
Winter (2005-2006)	-1,273,495	-1,658
Summer (2006)	-444,272	-1,880
Winter (2006-2007)	-456,736	-1,674
Summer (2000)	-433,618	-1,562
New York Interface		
	Net Scheduled Interchange	
Period	**(MWh)**	**(MW)**
Winter (2004–2005)	+2,384,210	+2,264
Summer (2005)	+1,383,733	+2,194
Winter (2005-2006)	+2,853,268	+2,246
Summer (2006)	+2,342,801	+2,006
Winter (2006-2007)	+1,921,563	+1,994
Summer (2000)	+2,164,005	+1,900

The winter and summer periods are based on the calendar definition of winter and summer.

Note: - (negative) values represents net imports and + (positive) values represents net exports.

d) Generation reserve margins which meet or exceed the NPCC resource adequacy criteria are considered adequate to provide reliable supply in Ontario in the operating timeframe. The applicable criterion is found in NPCC Document A-02 "Basic Criteria for Design and Operation of Interconnected Power Systems". The relevant portion of this document is:

"3.0 Resource Adequacy - Design Criteria

Each **Area's** probability (or risk) of disconnecting any **firm load** due to resource deficiencies shall be, on average, not more than once in ten years. Compliance with this criteria shall be evaluated probabilistically, such that the **loss of load expectation** [**LOLE**] of disconnecting **firm load** due to resource deficiencies shall be, on average, no more than 0.1 day per year. This evaluation shall make due allowance for demand uncertainty, scheduled outages and de-ratings, forced outages and de-ratings, assistance over interconnections with neighbouring **Areas** and **Regions**, transmission transfer capabilities, and capacity and/or load relief from available operating procedures."

The manner in which the IESO applies this criterion is described in document IMO_REQ_0041, "Ontario Resource and Transmission Assessment Criteria", Section 8, Resource Adequacy Assessment Criterion. For capacity planning purposes, where longer term decisions must be made, additional reserves to cover residual uncertainties and project delays may be appropriate. Also, the IESO does not consider emergency operating procedures for longer term capacity planning to be appropriate because the relief provided by these measures is intended to deal with emergencies rather than as a surrogate resource. Regular triggering of emergency operating procedures rather than developing appropriate resources could lead to the erosion of these emergency operating procedures through overuse. The extent to which all uncertainty is covered becomes an economic decision which should be guided by the NPCC criterion.

e) Applicable planning criteria and relevant links to such documents are discussed in the response to Board Staff Interrogatory 3.2.

Pollution Probe INTERROGATORY #43 List 4

Interrogatory

Ref. The System Impact Assessment Report For the Proposed Installation of Series Capacitors in the 500kV Circuits between the Bruce Complex & Nanticoke GS, CAA ID No. 2005-200, as referenced in Hydro One Networks' letter of November 26, 2007 to C. Pappas with attachment (see Attachment 1).

Issue Number 2.0
2.0 Issue: Project Alternatives

Request

On page 5, the report discusses a load flow analysis of the system with all eight Bruce nuclear units and all committed wind generation projects.

a) The report states: "Analysis has shown that regardless of the level of series compensation installed, it would not be possible to accommodate all eight Bruce units and all of the committed wind-turbine projects without having to employ generation rejection in response to a double-circuit contingency involving the 500kV circuits B560V & B561M."
   - i Please describe and list the series compensation assumptions studied in order to reach this conclusion.
   - ii Please estimate by substation the cost of installing the series compensation facilities that were assumed in the studies referenced in part i above.
   - iii Please describe and list the "near-term measures" referenced in slide 38 of 43 of Panel One of the Technical Conference of October 15, 2007 that were included in the studies performed to reach this conclusion.
   - iv Please provide saved cases in PTI-format, compatible with Siemen's PSS/E version 30, for the load flow studies performed by or for Hydro One, the OPA, and/or the IESO in studying the series compensation assumptions studied in order to reach this conclusion.

b) The report lists two alternatives, the second of which has two sub-options, for adding new transmission facilities required to accommodate all eight Bruce units.
   - i Please provide the estimated cost of Alternative 1, a new 500kV single circuit between Longwood TS and Middleport TS and all related facilities, and workpapers documenting the calculation of those costs.
   - ii Please provide the estimated cost of Alternative 2, option i, a new 500kV double circuit between the Bruce Complex and Milton TS and all related facilities, and workpapers documenting the calculation of those costs.

iii Please provide the estimated cost of Alternative 2, option ii, a new 500kV double circuit between the Bruce Complex and Essa TS and all related facilities, and workpapers documenting the calculation of those costs.

iv Please provide a saved case in PTI-format, compatible with Siemen's PSS/E version 30, for the load flow studies performed by or for Hydro One, the OPA, and/or the IESO in studying Alternative 1.

v Please provide a saved case in PTI-format, compatible with Siemen's PSS/E version 30, for the load flow studies performed by or for Hydro One, the OPA, and/or the IESO in studying Alternative 2, option i.

vi Please provide a saved case in PTI-format, compatible with Siemen's PSS/E version 30, for the load flow studies performed by or for Hydro One, the OPA, and/or the IESO in studying Alternative 2, option ii.

Response

a) i. The existing transmission facilities will only allow six units at the Bruce Complex to remain transiently stable following a double-circuit contingency involving the Bruce-to-Milton line.

Installing 20% series compensation on the Bruce-to-Longwood and the Longwood-to-Nanticoke circuits would, in effect, reduce the "electrical" length of these circuits. This would allow seven Bruce units, together with all of the committed wind-turbine projects, to remain transiently stable following the critical contingency. (Please refer to Table 3 of the Series Compensation SIA Report filed as part of response to Pappas Interrogatory 1).

Table 3 also shows that in order to maintain transient stability for all eight Bruce units and committed wind-turbine projects in-service it would be necessary to further increase the level of series compensation on the 500 kV circuits to:

- 40% on the Bruce-to-Longwood circuits; and
- 30% on the Longwood -to-Nanticoke circuit

However, the installation of series compensation on the 500 kV circuits comprising the Bruce-Longwood-Nanticoke corridor would thereby reduce the impedance of this corridor. This would encourage higher post-contingency flows via this corridor and a corresponding reduction in the flows over the 230 kV circuits from the Bruce Complex.

With the levels of compensation required for post-contingency transient stability with all eight Bruce units in-service, the post-contingency flow on the 500 kV circuit N582L would be well in excess of its long-term emergency rating. It would therefore not be possible to accommodate all eight Bruce units while respecting both the transient stability and the thermal limitations. With all eight Bruce units in-service, generation rejection would therefore be unavoidable.

With the levels of compensation required for post-contingency transient stability with seven units at the Bruce Complex in-service, the post-contingency flows on the 230 kV circuits B4V & B5V would exceed their long-term emergency rating.

The level of series compensation that would avoid overloading either the 500kV circuit N582L or the 230kV circuits B4V & B5V was found to be 30%. Since this level of series compensation exceeds the 20% level required to ensure that all seven Bruce units at the Bruce Complex together with the committed wind-turbine projects would remain transiently stable, post-contingency generation rejection would therefore not be required.

a) ii). The overall cost of 30% series compensation on the two circuits identified in Part (i) is estimated to be $97 million.

a) iii) Please refer to response to Pollution Probe Interrogatory 40.

a) iv) Please refer to Pollution Probe Interrogatory 30(e).

b) i) The SIA Report assessed the reliability of various options presented by Hydro One to the IESO. The IESO does not prepare or consider cost estimates for proposed new or modified connections to the grid. Given that all of the alternatives other than the Bruce to Milton Option were screened out by the OPA, detailed cost estimates of the screened out alternatives were not prepared by Hydro One.

To be helpful, and to obtain an order of magnitude estimate for the Longwood to Middleport Option, Hydro One has considered the likely facilities required and has used typical "per unit" costs as per the technique employed in response to Board Staff Interrogatory 2.3. Results for the are summarized as follows:

- A 48 km 500kV single circuit & 230 kV 2-circuit multi-voltage transmission line from Longwood TS to Buchanan TS to replace an existing 230 kV 2-circuit line ($144M)

- A 97 km 500 kV single circuit & 230 kV single circuit multi-voltage transmission line from Buchanan TS to Middleport TS to replace an existing 230 kV single circuit transmission line ($291M)

- Circuit termination equipment at each of Longwood TS and Middleport TS along with new 500 kV circuit breakers at each location ($40M)

- Additional modifications to the 500 kV switching arrangement at Middleport TS create a "breaker and a half" scheme for the existing equipment ($50M)

- New teleprotection equipment to protect the new circuits ($5M)

- Hence the estimated cost of this Alternative is $530M

(b) ii Please see the cost estimates provided in EB-2007-0050 Exhibit B Tab 4 Schedule 2.

(b) iii Please refer to response to Powerline Connections Interrogatory 69.

(b) iv- vi

Please refer to Hydro One's response to Pollution Probe Interrogatory No. 30(e).

Pollution Probe INTERROGATORY #44 List 4

Interrogatory

Ref. The System Impact Assessment Report For the Proposed Installation of Series Capacitors in the 500kV Circuits between the Bruce Complex & Nanticoke GS, CAA ID No. 2005-200, as referenced in Hydro One Networks' letter of November 26, 2007 to C. Pappas with attachment (see Attachment 1).

Issue Number 2.0

2.0 Issue: Project Alternatives

Request

On page 6 of the report, reference is made to the use of thyristor controlled series capacitors ("TCSCs") as a mitigating measure regarding sub-synchronous resonance.

a) What consideration has been given to the use of TCSCs on the electric system in Ontario?
b) Please provide a copy of any reports, analyses, conclusions etc. related to such consideration.
c) Please describe whether the use of TCSCs is considered desirable or undesirable, and please also explain why.

Response

Please refer to response Board Staff Interrogatory 3.1.

Pollution Probe INTERROGATORY #45 List 4

Interrogatory

Ref. The Addendum to The System Impact Assessment Report For the Proposed Installation of Series Capacitors in the 500kV Circuits between the Bruce Complex & Nanticoke GS, CAA ID No. 2005-200, as referenced in Hydro One Networks' letter of November 26, 2007 to C. Pappas with attachment (see Pollution Probe Interrogatory No. 43, Attachment 1).

Issue Number 2.0

2.0 Issue: Project Alternatives

Request

On page 4 of the addendum, reference is made to increasing the clearances over circuits B4V & B5V between Hanover TS and Orangeville TS so as to allow the maximum conductor operating temperature to be increased from 104^{o}C to 127^{o}C and thus increasing its LTE rating. Please provide the estimated cost of increasing the clearances on these circuits and provide workpapers documenting the calculation of these costs.

Response

The estimated cost of increasing the clearances on these circuits is $4.3 million. Please refer to Attachment 1.

Attachment 1

Hydro One Project Definition Report

Project Definition Report

Uprate 230kV 2 Circuit line
Bruce A TS x ORANGEVILLE TS (B4V/B5V)

Investment Plan #13658

Feb. 15, 2007

1. Introduction & Background

B4V/B5V is a 230kV double circuit line connecting Bruce A TS and Orangeville TS. Two new generating stations, Enbridge Underwood CTS and Canadian Hydro's Armaranth CTS, are being connected directly to the line. The expected new generation, as well as the expected return of Bruce units, increases the loading on these two circuits.

The Hanover TS to Orangeville TS section of B4V/B5V has a summer continuous rating of 432 MVA (1060 A) per circuit and an emergency rating of 485 MVA (1190 A) based on a sag temperature of 104˚C. In a contingency the minimum post generation rejection current carrying capability required is 1306 A per circuit. Thus there is a need to uprate the Hanover TS to Orangeville TS section of the double circuit from the existing sag temperature of 104˚C to 127˚C to provide an emergency current carrying capability of 1400A per circuit.

This report provides cost estimates for this line uprating project for an in service of January 2009.

2. Scope Summary

The B4V/B5V line section between Hanover TS and Orangeville TS will be upgraded to class "C" security.

- Re-tension the conductors on select spans.
- Install new extended middle arms for seven (7) X2S type towers
- Reinforce 31 towers:
- Minimize project and Hydro One environmental risk by ensuring that all aspects of project remain in full compliance with legislated requirements.
- Revise existing line B4V, B5V protection settings to accommodate the new line impedance due to uprating of the two circuits.
- Telecom facilities as required for the uprating of the circuit.

3. Assumptions

LINE

1. Maximum operating temperature is 127^{o}C
2. The line shall be modified to southern Ontario class "C" security (1" radial ice with no wind; 80-mph gust with no ice; ½" radial ice with 50-mph gust; anti-cascading loads)
3. The towers, conductors, ground wire, hardware, and insulators are in good condition and shall not be replaced (although we recommend insulator and GW replacement).
4. The line section between Bruce GS and Hanover TS is not included in this estimate and shall not be upgraded to class "C" security.

ENV

1. no tower extensions or any changes in tower heights (no EA requirements);
2. no towers added or removed;
3. no changes in Right of way alignment;
4. built road access required to approximately 25 structures;
5. in agricultural areas where roads must be built, no soil will be removed or stockpiled (no significant soil/spoil testing or disposal off-site);
6. no culverts to be installed in municipal drains/creeks/ditches

7. Stage 2 Archaeology assessment for built access and P/T locations will likely be required due to proximity of significant water bodies/courses
8. no landscape design/contract requirements (existing R/W with no altered visual impacts).

4. Risks

1. Tower inspection and condition assessment were NOT made. The towers are close to 50-years old and are likely suffering from deterioration symptoms such as corrosion, member deformations, soil erosion, etc. Inspection and assessment of the towers shall be made in the execution stage of the project.
2. The ground wire rated tension of 11300 lb is very low for large spans (ruling span is ≈ 1400') and would result in larger sag than the conductors. Galloping performance and electrical clearances between the conductors and ground wire may decrease as a result of re-tensioning the conductor.

Note: If ground wire is replaced it may require further modification of structures.

3. Fault current was not considered as a design issue in this estimate i.e. no increase in the fault current to necessitate changing the ground wire, although installing new distributed generation (DG) to the electric power system in the area would likely to increase the fault current.
4. There are information discrepancies between Line condition survey, GIS system, and the Plan & Profile drawings. The estimate was made based on the best available information. There is a risk that the information used in this estimate may not be accurate and that may trigger additional line modifications. The information and assumptions will be verified during the design phase.
5. Major constraints encountered during archaeological survey
6. First Nation consultation required on this project

5. Outage Requirements

Staged outages will be required on B4V and B5V during the construction of this project
Co-ordination of outages with Melancthon Wind Farm will be required. Outage management have indicated that single circuit outages should be available to do this work in 2008. Circuits may need to be returned over some weekends in order to undertake routine maintenance. A new tap to the Melancthon Wind farm, from B5V is scheduled for mid November 2008. It will be a requirement that Construction complete the upgrading on B5V before the tap connection is made.

6. Projects Costs

The total cost of the project is $4.3 M.

	SUMMARY
Past Costs	$50
Project Mgmt	$40
Engineering	$160
Procurement	$1,070
E&CS Construction	$2,000
Commissioning	$30
Contingency / Risk	$300
Removals	$60
Interest &OH	$590
GROSS INVESTMENT	**$4,300**

2007	2008	2009	Total
$0.3	$3.7	$0.3	$4.3 M

7. Schedule

A brief summary is as follows:

Engineering	Nov 2006	- May 2008
Approval (Hydro One Board) for Project to Proceed		- Apr. 2007
Procurement	Apr. 2007	- May 2008
Line Construction	Jan. 2008	- Jan .2009
Station Construction	Oct. 2008	- Jan. 2009
Commissioning	Nov. 2008	- Jan. 2009
Project In-Service		**- Jan. 2009**
Line Construction (road removal & clean up)	May 2009	- July 2009

Pollution Probe INTERROGATORY #46 List 4

Interrogatory

Ref. Exh. B/T 6/S 5, Appendix 2

Issue Number 2.0
2.0 Issue: Project Alternatives

Request

a) On page 3, it states that 30% series compensation may be used as a stopgap measure to expand transmission capability to accommodate eight Bruce units if approvals for the new 500 kV line are delayed.
   i Please provide a copy of any studies, analyses, results, or reports produced as a result of the IESO's, the OPA's, and/or Hydro One's assessment of series compensation.
   ii Please provide a saved case in PTI-format, compatible with Siemen's PSS/E version 30, for the load flow studies performed by or for Hydro One, the OPA, and/or the IESO in studying the use of 30% series compensation.
b) On page 3, it states that interim measures, such as generation rejection and series compensation are not alternatives to the long-term solution since they increase the risk to the security and reliability of the power system.
   i Please provide a copy of any studies, analyses, results, or reports produced as a result of the IESO's, the OPA's and/or Hydro One's assessment of generation rejection.
   ii ii. Please describe how the use of series compensation increases the risk to the security and reliability of the power system, and please also provide a copy of any letters, reports, studies, analyses, etc. which support this opinion.
   iii Please describe how the use of generation rejection increases the risk to the security and reliability of the power system, and please also provide a copy of any letters, reports, studies, analyses, etc. which support this opinion.
c) On page 3, it states that Hydro One has expressed concern regarding the system and equipment risks of using series compensation. Please provide a copy of the document(s) in which these concerns are expressed.
d) On page 3, it states that the OPA will retain third party experts to undertake a due diligence study to assess the suitability and risks associated with the use of series compensation for this application.
   i Please describe the status of this due diligence study.
   ii Please provide a copy of any reports, analyses, recommendations etc. that have been prepared as a result of or are related to this due

diligence study.

e) On page 3, it states that the use of generation rejection is subject to NPCC approval.

i Has NPCC ever rejected a request to use generation rejection in the Province? If yes, please provide a copy of the request(s) and the NPCC response(s) regarding the request(s).

ii Has NPCC ever rejected a request to use generation rejection for generation located in the Bruce Complex? If yes, please provide a copy of the request(s) and the NPCC response(s) regarding the request(s).

iii Please describe if generation rejection has ever been used for generation located in the Bruce Complex. If yes, please provide a copy of the request and the NPCC response regarding each such use of generation rejection.

Response

a) i. Please refer to the response to Pappas Interrogatories 1 and 6.

ii. Please refer to the letter from Hydro One to the Board dated March 13, 2008, at page 5, with respect to paragraph 3 of Procedural Order 5. To better utilize the resources available at the IESO and to obtain the maximum benefit from those resources, the IESO has proposed that it should perform a reasonable number of studies for Pollution Probe, at their specific direction. The results of these studies would then be provided to Pollution Probe in a format suitable for filing as evidence.

b) i. and ii.

Please refer to the responses to Board Staff Interrogatory 1.4, Saugeen Interrogatory 11 and Pappas Interrogatory 6 for information regarding generation rejection provided by Hydro One and OPA.

The IESO has not published any formal studies that assess generation rejection. However, the following analysis demonstrates that, to comply with the NPCC criteria as set out in Document A2, "Basic Criteria for Design and Operation of Interconnected Power Systems," in the absence of a new 500kV line from the Bruce Complex to Milton TS, the maximum amount of generation capacity that could be dispatched at the Bruce Complex would be seven units. Clause 6.3 of Document A2 is quoted below:

6.3 Post Contingency Operation

Immediately after the occurrence of a **contingency**, the status of the **bulk power system** must be assessed and transfer levels must be adjusted, if necessary, to prepare for the next **contingency**. If the readjustment of generation, load resources, phase angle regulators, and direct current facilities, is not adequate to restore the system to a secure state, then other measures such as voltage reduction and shedding of firm load may be required. System adjustments shall be completed as quickly as possible, but in all cases within 30 minutes after the occurrence of the **contingency**.

Voltage reduction need not be initiated and firm load need not be shed to observe a post-**contingency** loading requirement until the **contingency** occurs, provided that adequate response time for this action is available after the **contingency** occurs and other measures will maintain post-**contingency** loadings within **applicable emergency limits**.

Emergency measures, including the pre-contingency disconnection of **firm load** if necessary, must be implemented to limit transfers to within the requirements of 6.2 above.

Clause 6.2 notably states:

Stability of the **bulk power system** shall be maintained during and following the most severe of the following **contingencies**, and **with due regard to reclosing**:

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

b. The loss of any **element** without a fault.

Immediately following the most severe of these **contingencies**, voltages, line and equipment loadings will be within **applicable emergency limits**.

The following describes how the application of the A2 criteria would affect the operation of the system without a new 500kV line from the Bruce Complex, and using generation rejection.

Diagram 1 (attached) shows the results of a load flow study with 30% series compensation installed on the Bruce x Longwood and the Longwood x Nanticoke 500kV circuits. Seven Bruce units are in-service, together with the 675MW of committed wind-turbine projects.

The transfer across the Negative-BLIP Interface has been adjusted to be approximately 500MW (the actual transfer is 576MW).

Following a contingency involving the Longwood x Nanticoke 500kV circuit, N582L, the system would then have to be re-prepared for the next contingency. The internal resources available to the IESO for the required adjustments would total approximately 900MW. This represents the 10-minute Operating Reserve that has to be maintained on the system to cater for the potential loss of one 900MW generating unit at Darlington GS.

As shown in Diagram 2 (attached), this 900MW has been used to back-down the 200MW Leader Wind Farm and to reduce the transfers across the Negative-BLIP Interface. As shown, this action has resulted in a Positive-BLIP transfer of approximately 100MW.

Comparing Diagrams 1 and 2 demonstrates that there is no overall increase in transmission losses following the re-preparation of the system.

Diagram 3 (attached) shows the results of a subsequent contingency involving the 500kV double-circuit line between the Bruce Complex and Milton TS.

In response to this contingency, two of the generating units at the Bruce Complex would need to be rejected. It has also been assumed that approximately 15% of the resulting resource deficiency (1600 MW) would be automatically compensated through the response of the governors on the generating units in Ontario. The combined output from the units at Darlington GS has been increased by 250 MW as a proxy for this action.

The post-contingency flows on the 230 kV circuits between Longwood TS and Buchanan TS and also from the Bruce Complex are shown to be at, or marginally below, their respective thermal limits.

Comparing Diagrams 2 and 3 shows a net increase of approximately 1520 MW in the transfers into Ontario via the Interconnections with New York and Michigan. A further increase of approximately 80 MW is shown in the transfer across the Flow South Interface, representing increased transfers via the Interconnections with Manitoba and Minnesota. The net effect of tripping the two units at Bruce GS in response to a double-circuit contingency involving the Bruce to Milton line would be an increase of approximately 1600 MW in the transfers via the Interconnections with our neighbouring utilities. Since this would exceed the agreed limit of 1500 MW, corrective action would therefore need to be taken.

These studies effectively demonstrate that to comply with the A2 criteria and in the absence of a new 500 kV line from the Bruce Complex to the Milton SS, the maximum amount of generation capacity that could be dispatched at the Bruce Complex would be seven units. In addition, with seven Bruce units dispatched together with all of the committed wind-turbine projects, the transfers across the Negative-BLIP Interface would need be limited to a maximum of approximately 500MW.

iii. Please see the response to Board Staff Interrogatory 3.2.

c) Hydro One's concerns were included in comments provided to the OPA in response to its Transmission Discussion Paper #5, as part of the stakeholder consultation process of the IPSP. Comments made in respect of the long-term use of the interim measures on the Bruce to Milton Transmission Project were stated as follows:

<u>Concerns about Long-Term Use of Interim Measures for the Bruce Transmission system</u>

While it is preferable to have the new 500 kV transmission line between the Bruce area and the GTA constructed as soon as possible, as noted in the Transmission Document, it is unlikely that the new line will be in-service until late 2011. Therefore, the Transmission Document proposes to use near-term and medium-term interim power system measures such as the installation of significant amounts of shunt capacitor banks and static var compensation (SVC); provision for generation rejection equivalent to up to two units at the Bruce Power complex; and the installation of 30 % series compensation on the Bruce to Longwood to Nanticoke 500 kV circuits providing OPA studies conclude it is consistent with good utility practice.

Hydro One recommends that reliance on these interim measure should be limited to as short a time period as possible and the need for these measures should be obviated in the longer term by building a new transmission line out of the Bruce area This recommendation is based on significant concerns about the use of the interim measures from the perspective of the difficulties in operation and maintenance of the transmission system, potential for increased occurrences of transmission congestion, and the reduced reliability of the power system. Some of these concerns are summarized below.

<u>Use of Series Compensation</u>

- The installation of series compensation in SWO would represent a unique application of this technology since it would result in series compensation being used on circuits connected to more than 6,000 MW of mostly nuclear generation in the most critical part of the interconnected North American power system.

- Hydro One is cognizant of the fact that series compensation is a proven transmission technology outside Ontario. However, Hydro One's past experience is that newly installed products or technologies are prone to suffering unexpected malfunctions or mis-operations during their initial deployment due to unexpected design or manufacturing deficiencies. Such "teething pains" have resulted in prolonged equipment unavailability and/or adverse system impacts. These outcomes, coupled with the substantial reliability and commercial consequences of the series compensation performing poorly, unique power system characteristics, protection implications, and concerns about system operability, necessitate the need for due diligence considerations for this option, in the context of its utilization in Southwestern Ontario, as indicated in the Transmission Document.

d) i. The due diligence report on the use of series capacitors for this project is complete.
Please refer to the response to Pappas Interrogatory 6.

ii. Please refer to the response to Pappas Interrogatory 6.

e) i. Generation rejection schemes, like other forms of Special Protection Systems, must go through an NPCC approval process before being employed. During this process, the IESO must demonstrate that the generation rejection scheme allows for proper system operation, and that the risks of improper system operation are either acceptably low or that the consequences of improper operation are acceptable. Once a Special Protection System has been approved for use by the NPCC, it is the responsibility of the IESO to ensure the SPS is judiciously used.

ii. The NPCC has never rejected a request to use generation rejection for generation located in the Bruce Complex.

iii. Requests are not made to the NPCC to arm generation rejection – as explained in part i) above it is the responsibility of the IESO to ensure the SPS is judiciously used. The Bruce Special Protection System (BSPS), whose main feature enables the arming of Bruce units for rejection, has been heavily used in the recent past. During the course of the past three years the BSPS has been armed to reject at least one unit for the Bruce-Milton, Bruce-Claireville 500 kV double circuit contingency for between 4,300 to 5,500 hours per year. In this same period, two units have, on average, been armed for approximately 1,100 hours per year. Without arming, generation would have become congested during this period. The commitment to put more generation in the Bruce Area will increase arming until transmission enhancements are made. Arming is already at its maximum amount during a significant portion of the year.

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

Pollution Probe INTERROGATORY #47 List 5

Interrogatory

Ref. Response to Pollution Probe Interrogatory No. 7 List 1 (Exh. C / T 2 / S 7)

Issue Number 2.0
2.0 Issue: Project Alternatives

Request

a) Please provide all workpapers associated with the computation of lockedin energy quantities listed in the "undelivered energy (MWh)" table for parts a) through e) of the response. Provide these workpapers in Excel or equivalent spreadsheet format with formulas intact.
b) Please describe in complete detail the analysis conducted to obtain the estimate of locked-in energy provided in the "undelivered energy (MWh)" table as a response to parts a) through e) of the interrogatory. Please include descriptions of the temporal detail for each component of the response (e.g. for wind, nuclear, and transmission components).
c) Please provide the estimates of locked-in energy for the finest level of temporal detail calculated.
d) Please provide the "probabilistic distributions" for both wind and nuclear generation that was developed as part of the response.
e) Please provide the "probabilistic distribution of total generation in the Bruce area" that was developed as part of the response.
f) Please provide the "transfer-capability probability distributions" that were developed as part of the response.
g) Please describe the specific assumptions made concerning the overall state of the Ontario transmission system for the periods in which Bruce area transfer-capability probability distributions were developed.

Response

a) Hydro One and OPA have declined to answer this Interrogatory due to its confidential and commercial sensitivity. Please refer to correspondence on behalf of Hydro One dated March 13, 2008.

b) The analysis used to respond to Pollution Probe Interrogatory 7 is based on the fact that the output of wind generation and nuclear generation, and the capability of the Bruce transmission system are not constant. The OPA's Financial Evaluation Model ("Model") uses probabilistic distributions developed from historical data for wind and transmission capability information, and from estimates of nuclear unit availability from a probabilistic derivation. The Model considers eight different time periods within a year (to match the time periods used in the energy cost tables and as described in response to Pollution Probe Interrogatory 24) and three different refurbishment states (these refurbishment states are user-selected in operating the Model) in its calculations. In order to simplify the calculations, the Model uses a representative sample from each distribution.

With regard to each distribution, the variability of wind generation output is modeled using the simulated hourly data from the AWS True Wind Report. The wind generation output distributions for each time period are created by allocating the AWS data to each of the eight time periods.

The nuclear generation distribution modeling is based on the number of units in operation (i.e. eight units less the number removed for refurbishment, as selected by the user), the units' Effective Forced Outage Rate (EFOR) and the units' planned outage assumptions. A two-state model is used in conjunction with these assumptions.

Transmission capability is determined based on normal system conditions established by the IESO, less a reduction (referred to as a penalty) to reflect other real-time system limitations on the Bruce Area transmission system. The Model uses a penalty distribution based on Bruce Area transmission system historical performance data between 2005 and 2007.

Total generation distributions cannot be created by adding the wind generation and nuclear generation distributions together. It is assumed that the wind and nuclear generation are independent events. Therefore, the Model conducts a convolution of the wind generation and nuclear generation distributions to determine the total generation distribution for the Bruce Area. (A convolution of a discrete number of samples is conducted by taking every possible combination of two points, one from each distribution. The number of samples is chosen by the model user.)

Undelivered energy distributions are determined by conducting a convolution of the transmission capability and total generation distributions. The expected values of these distributions are scaled to represent the number of hours in the corresponding time period. The only temporal parts of the Model's analysis are created when these expected values are assigned to the user-selected monthly refurbishment profile. These monthly values are then totaled to provide annual results.

c) Hydro One has been advised by the OPA that it has declined to respond to this Interrogatory as this information could be used to determine the Bruce A Refurbishment schedule, which is confidential information. Please refer to correspondence dated March 13, 2008 to the Board sent on behalf of Hydro One.

d) The Model used to determine the amount of undelivered energy considers probabilistic distributions for wind and nuclear generation for each year of study. The wind generation is modeled for each of the eight time periods discussed in the above-referenced response. The nuclear generation is modeled for two time periods (winter/summer and shoulder) and three different states at Bruce NGS (zero, one and two units removed for refurbishment). There are 266 probabilistic distributions representing nuclear and wind generation for the entire study period between 2012 and 2030. All of the distributions are similar; therefore only one wind generation probabilistic distribution and one nuclear generation probabilistic distribution are shown in Figures 1 and 2 below. The Model cannot process the entire distribution and needs to sample it in order to conduct its calculations. The sampled distribution is shown by the red line that moves stepwise. The Model uses an average sampling method and does not take into account the peak values (making any calculations conservative ones, such as those in the response to the referenced interrogatory).

Figure 1

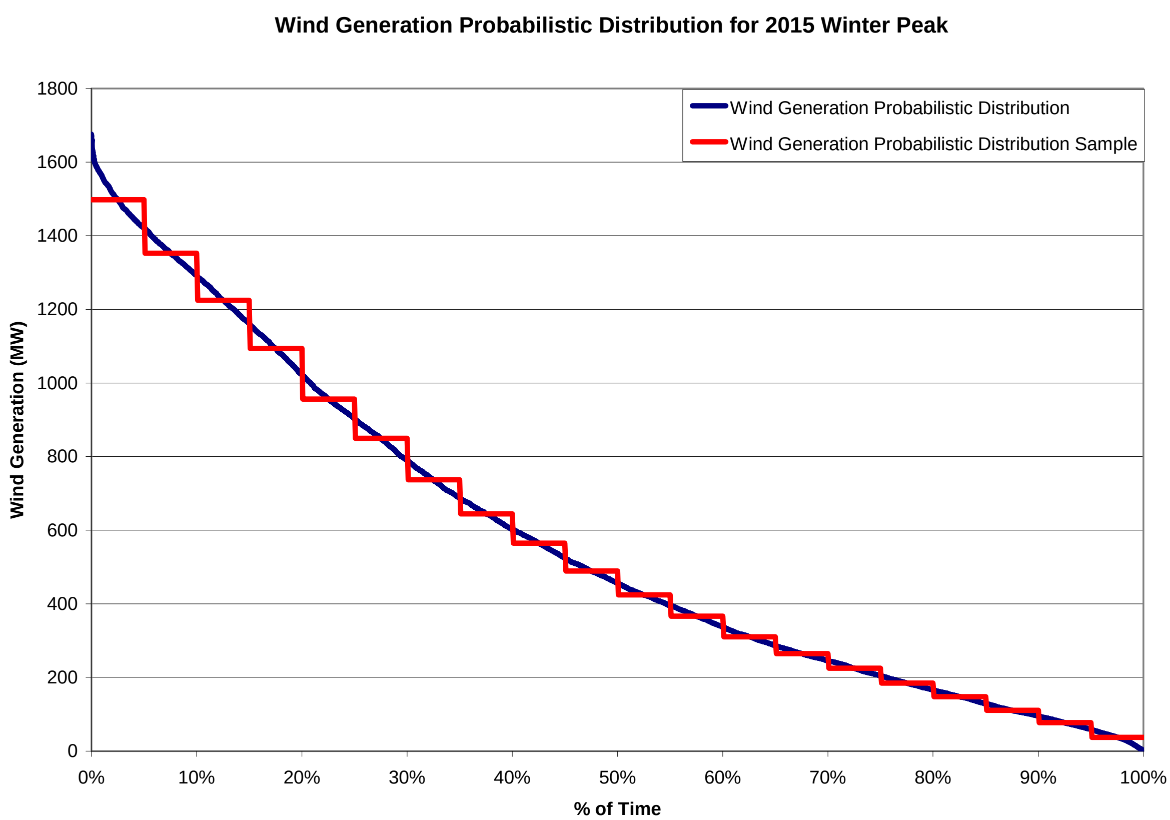
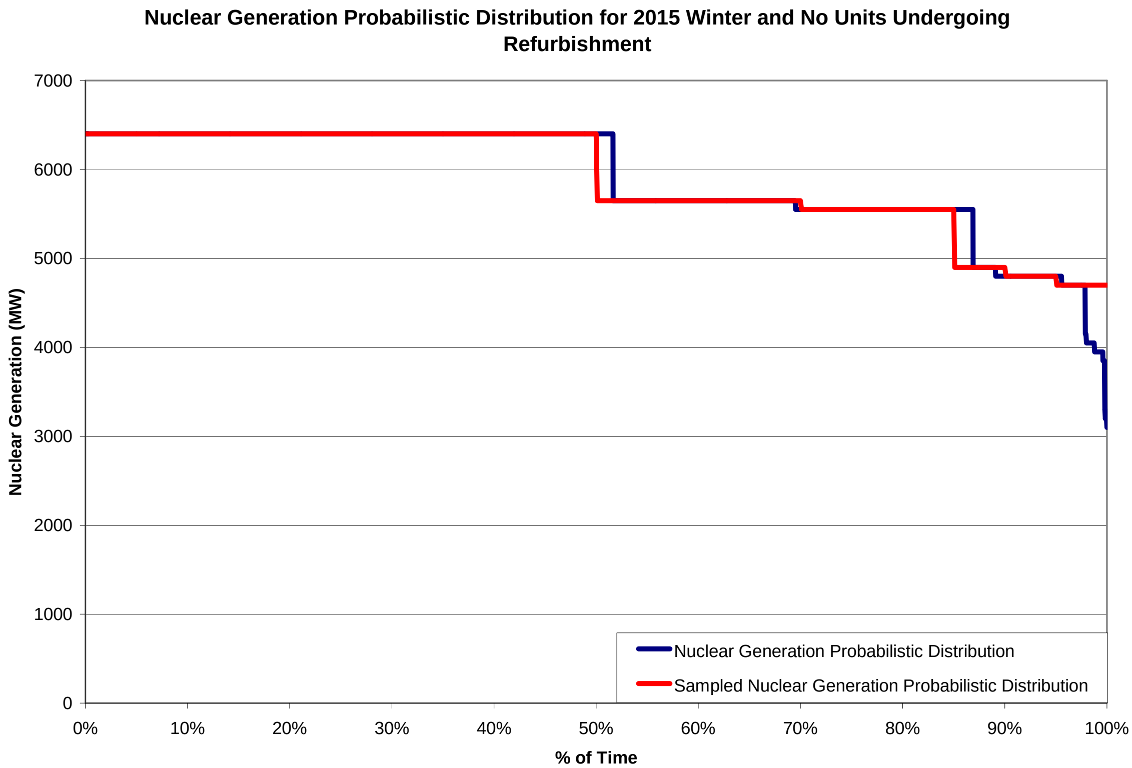
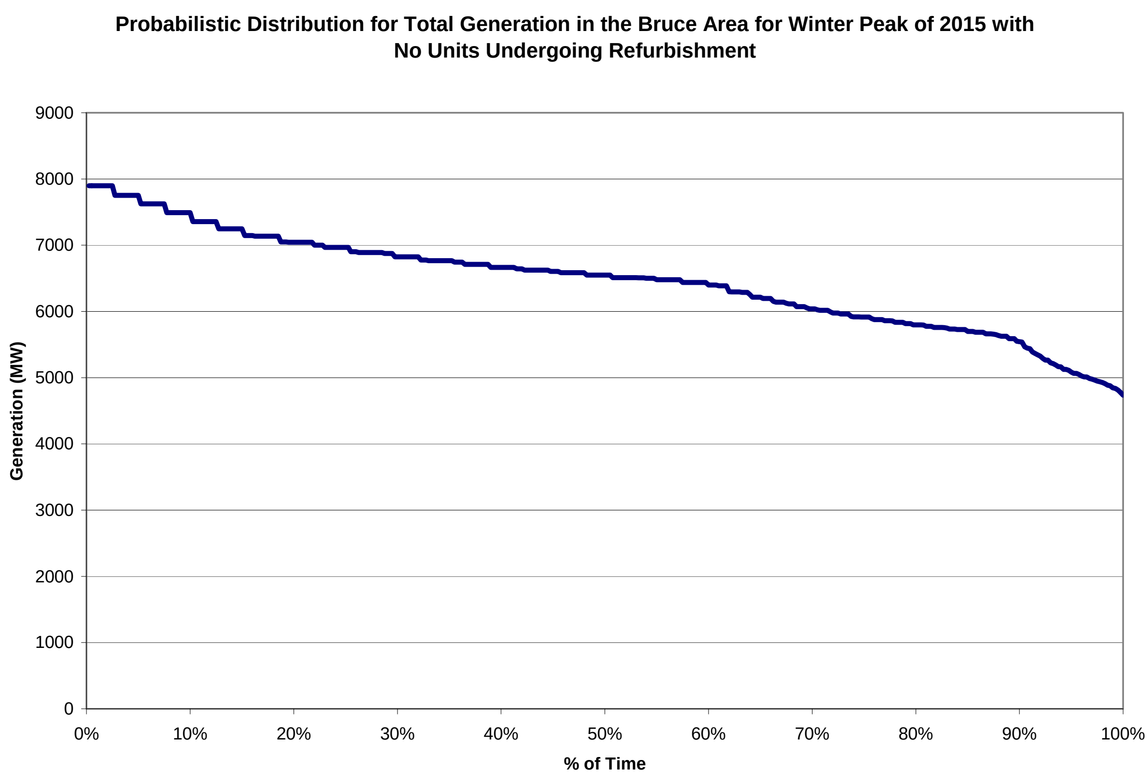


Figure 2



e) There are 24 total generation cases modeled for each year of study. This totals 456 distributions for the study period. Again, because all of the distributions are similar, only one example of this distribution is shown in Figure 3 below.

<u>Figure 3</u>



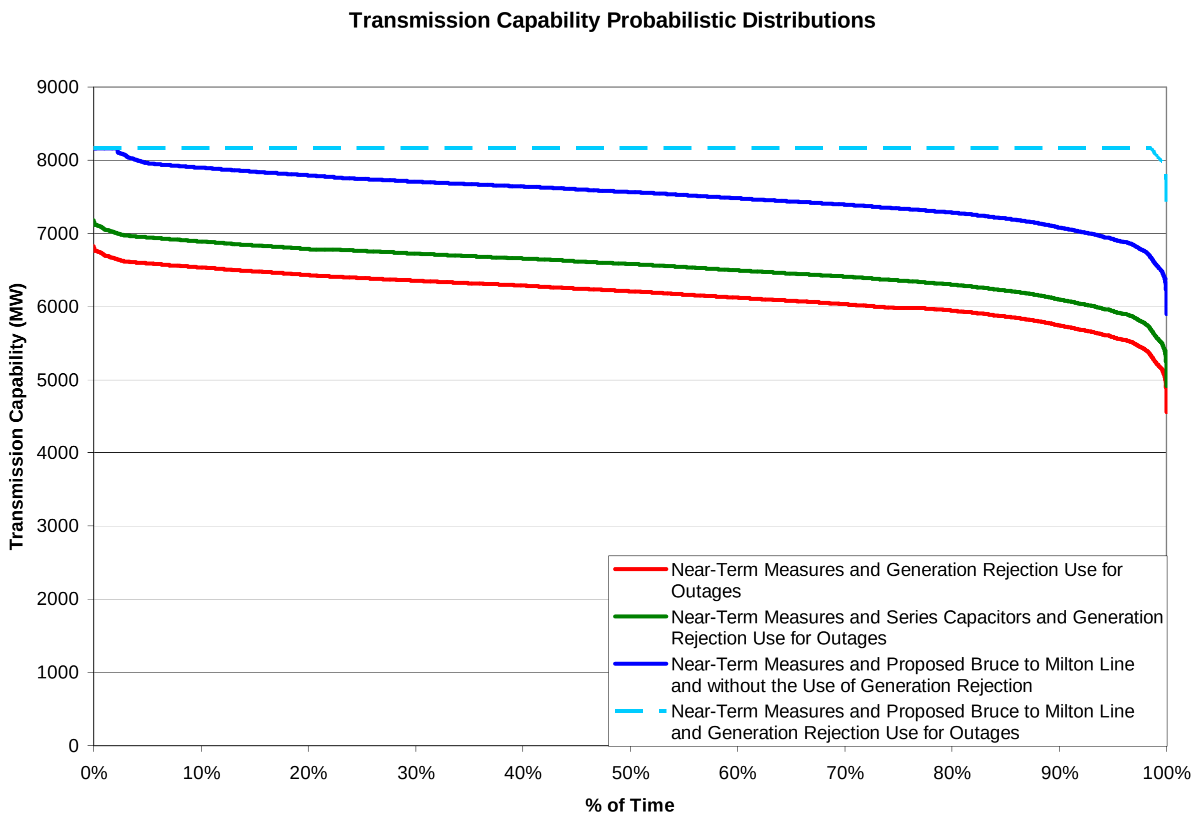
f) As explained in the response to part b) of this Interrogatory, transmission capability is modeled using normal system limits calculated by the IESO and historical transmission system penalty information. The Model takes into account historical de-rating patterns and uses these results in the consideration of future transmission capability. The resulting reduction in the transmission capability (i.e. the penalty) to the Bruce Area transmission system would be the same for each transmission system configuration (e.g., series capacitors, new Bruce to Milton line, etc.). The Model also assumes that the penalty would be the same for the study duration. Both of these assumptions are conservative as it is likely that a transmission system employing the new Bruce to Milton line would be more robust and would have a lower penalty due to transmission system outages, as compared to one employing series capacitors. This is because stress caused to the existing system using series capacitors would expected to be much higher and a larger transmission penalty (i.e. consequences) would likely result for any particular outage.

Also, it is expected that as the transmission system ages, outages would become more frequent and cause a larger penalty sustained for a longer period of time in the future.

Figure 4 shows transmission capability for each of the systems that the OPA modeled. Note that the capability of the proposed Bruce to Milton line drops below the 8,100

MW level in the distribution. This is due to the fact that generation rejection was not modeled for this option under outage conditions, while it was modeled for the other two cases. If generation rejection were to be assumed for the Bruce to Milton option under outage conditions (which will be the normal operating mode), the capability of the Bruce to Milton option would be able to be maintained at the 8,100 MW level throughout the period as illustrated in Figure 4 by the dashed line on the graph. This comports with the identified level of required or needed transfer capability fro the Bruce Area.

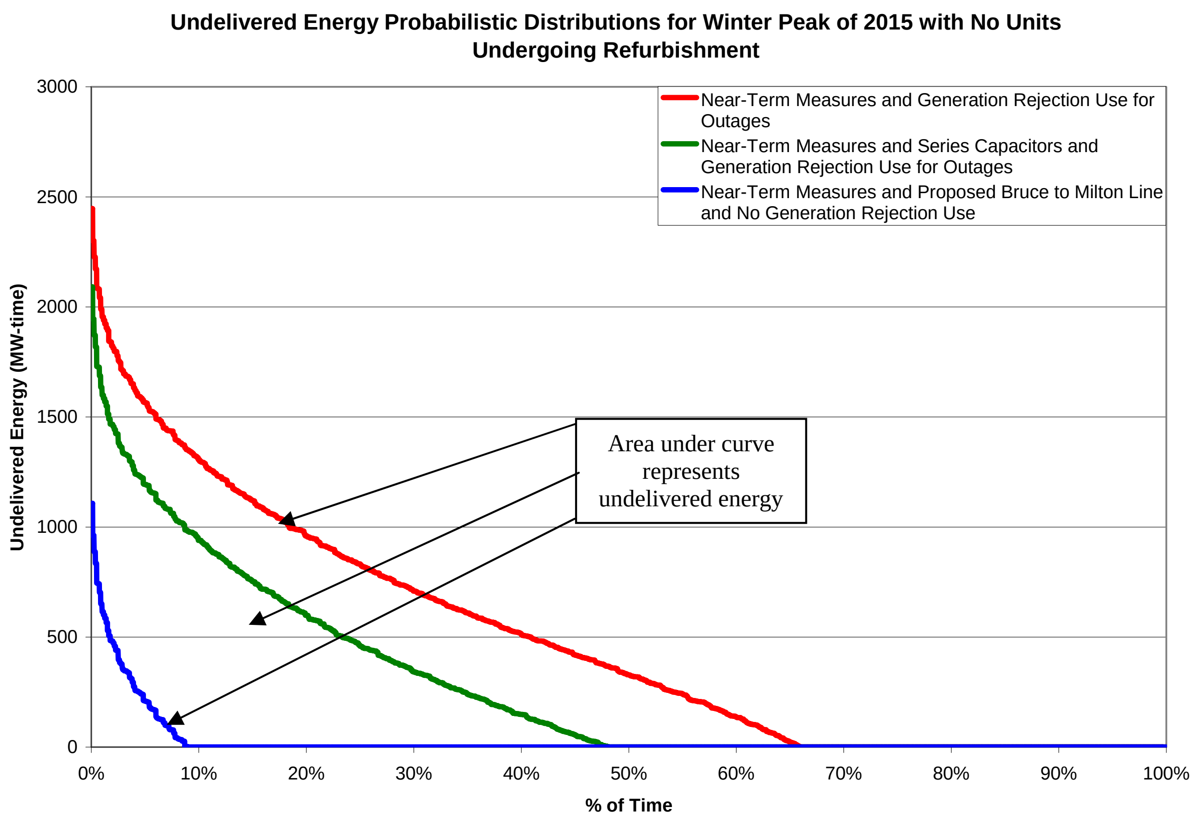
Figure 4



The transmission capability distributions shown in Figure 4 are then sampled in the same way as those for nuclear and wind generation. The transmission capability and total generation distributions are then convolved to derive the undelivered energy distribution. There are 456 undelivered energy distributions for each transmission system modeled. An example of the undelivered energy distribution for the winter peak in 2015 with no units undergoing refurbishment for both the proposed Bruce to Milton line (without any GR use) and for the series capacitor option (with GR use under outage conditions) is shown in Figure 5 below.

The undelivered energy is determined by using the expected value (mean) of these distributions to calculate undelivered energy for a certain period of time. Figure 5 below shows the undelivered energy calculated for the 2015 winter peak period. The winter peak period is one of the eight time periods used for the annual calculation. The area under each of the curves is a component of the amount of the 2015 undelivered energy in the table of undelivered energy values provided in the response to Pollution Probe Interrogatory 7.

<u>Figure 5</u>



The results of the OPA's analysis show that the Bruce transmission system reinforced with the Bruce to Milton line will have minor amount of undelivered energy incurred during equipment outage conditions. That small amount would be eliminated through the infrequent use of GR under those conditions. On the other hand, Figure 5 also depicts that the Bruce transmission system when reinforced only with series capacitors (and assuming the use of GR only under outage conditions) is expected to result in a significant amount of undelivered energy. For 2015 this amount is expected to be 1.3 TWH and is approximately 20% of the energy output of a Bruce A unit operating 100% of the time at 750 MW. Using the OEB-approved CDM avoided cost forecast as a proxy for the price of the replacement energy in 2015, the amount would be $63 million expressed in 2007 dollars. Please refer to Pollution Probe

Interrogatory 9. Over the entire study period, the net present value of the undelivered energy for the series capacitors option is $540 million expressed in 2007 dollars. This amount does not take into account transmission losses.
Figure 5 also shows the undelivered energy associated with reinforcing the Bruce transmission system with only the near-term measures. For 2015, undelivered energy is 2.6 TWH or 40% of the energy output of a Bruce A unit operating 100% of the time at 750 MW. Using the OEB-approved CDM avoided cost forecast as a proxy for the price of the replacement energy in 2015, the amount would be $120 million expressed in 2007 dollars. Please refer to Pollution Probe Interrogatory 9. Over the entire study period, the net present value of the undelivered energy for the near term measures option is approximately $1.1 billion expressed in 2007 dollars. This amount does not take into account transmission losses.

While the amount and cost of undelivered energy are important considerations, the frequency of exposure to congestion on the Bruce transmission system is also a critical measure of the impact of system constraints. As shown in Figure 5, the system is expected to be congested for a large percentage of time (e.g. approximately 50 % of the time for series compensation and close to 70% of the time for the near-term only measures option). Operation of the system with congestion would create complexities and create operational inefficiencies. For example, the Bruce nuclear units would have to operate with constrained output, there would be need for more frequent arming of the wind and nuclear units for rejection, and, when the limit of the ability to maneuver the output of the Bruce units is reached, there would be need to curtail the output of wind generation.

g) Please refer to the response to part f) above.

Pollution Probe INTERROGATORY #48 List 5

Interrogatory

Ref. Response to Pollution Probe Interrogatory No. 8 List 1 (Exh. C / T 2 / S 8), Exh. B / T 1 / S 1, Exh. B / T 4 / S 4, and Exh. K / Tab 1

Issue Number 1.0
1.0 Issue: Project Need and Justification

Request

Please provide estimates of the Bruce area locked-in installed capacity (MW) for each of the scenarios a) through e) described in Pollution Probe Interrogatory #8 List 1.

Response

For the purposes of this response, it is assumed that "installed capacity" means 100% of the net capacity of each generation station. The table shown below is the calculation of locked-in installed capacity for the Bruce Area for each of the 5 scenarios requested.

Locked-in Installed Capacity (MW)

Year	Part a)	Part b)	Part c)	Part d)	Part e)
2012	148	148	0	0	0
2013	1230	1230	875	875	875
2014	1700	1700	1345	1345	1345
2015	1915	1915	1560	1560	1560
2016	1915	1915	1560	1560	1560
2017	1915	1915	1560	1560	1560
2018	1065	1065	710	710	710
2019	215	215	0	0	0
2020	215	215	0	0	0
2021	215	215	0	0	0
2022	215	215	0	0	0
2023	1065	1065	710	710	710
2024	1915	1915	1560	1560	1560
2025	1915	1915	1560	1560	1560
2026	1915	1915	1560	1560	1560
2027	1915	1915	1560	1560	1560
2028	1915	1915	1560	1560	1560
2029	1915	1915	1560	1560	1560
2030	1915	1915	1560	1560	1560

Pollution Probe INTERROGATORY #49 List 5

Interrogatory

Ref. Response to Pollution Probe Interrogatory No. 9 List 1 (Exh. C / T 2 / S 9)

Issue Number 1.0
1.0 Issue: Project Need and Justification

Request

a) On what basis is the assumption made that "the cost of undelivered energy is equal to the cost of the replacement energy"?
b) On what basis is the assumption made that energy costs are "those" in the OEB-published Total Resource Cost Guide?
c) Please confirm or correct a reference: the response indicated that energy costs were those in the OEB-published TRC Guide at Table 11, however there is no Table 11 in the TRC Guide available on the OEB website.
d) Please provide all workpapers, including spreadsheets with formulas intact, used in computing the values in the response tables "Undelivered Energy Cost (M$2007)" for both the "OPA Discount Rate" version and the "Hydro One Discount Rate" version.

Response

a) The generation in the Bruce Area is wind and nuclear-fueled. As such, the energy produced from these resources is one of the lowest costs on the system and supplies load as often as the generator and fuel is available. Any undelivered energy caused by transmission constraints on the Bruce transmission system would require additional energy of similar amount from other generation sources to enter the system to supply load. For the purpose of this Interrogatory, this is defined as the "replacement energy." The cost of this replacement energy is an incremental cost to ratepayers and is assumed to be the cost of purchasing this amount of energy at the system marginal price at the time of the constraint on the Bruce transmission system. For purposes of the analysis the system marginal price that has been used is the avoided energy cost, which is a proxy for the Hourly Ontario Energy Price on a forecast basis.

b) Forecasts of avoided energy costs for evaluating the value of savings from conservation measures are contained in the report entitled "Avoided Cost Analysis for the Evaluation of CDM Measures," dated June 14, 2005, prepared by Navigant Consulting for Hydro One. This report was used to estimate the cost of the undelivered energy from the Bruce area as it is the only OEB-approved energy avoided cost forecast to date.

c) Yes. The reference should have been Table 11 of “Avoided Cost Analysis for the Evaluation of CDM Measures.”

d) Hydro One and OPA have declined to answer this Interrogatory due to its confidential and commercial sensitivity. Please refer to correspondence on behalf of Hydro One dated March 13, 2008.

Pollution Probe INTERROGATORY #50 List 5

Interrogatory

Ref. Response to Pollution Probe Interrogatory #10 List 1 (Exh. C / T 2 / S 10)

Issue Number 1.0
1.0 Issue: Project Need and Justification

Request

a) Please provide all workpapers, including spreadsheets with formulas intact, used in computing the values in the response tables "Net Present Cost of Expanding the BSPS" for both the "OPA Discount Rate" version and the "Hydro One Discount Rate" version.
b) If these workpapers do not show how the LIE column is computed, please explain how it is computed and please also explain how the LIE column differs from the estimate of undelivered energy cost provided in response to Pollution Probe Interrogatory No. 9 List 1.

Response

a) Hydro One and OPA have declined to answer this Interrogatory due to its confidential and commercial sensitivity. Please refer to correspondence on behalf of Hydro One dated March 13, 2008.

b) List 1 in the response to Pollution Probe Interrogatory 9 has had the cost of undelivered energy adjusted to 2007 dollars using the OPA discount rate, as requested. The table in the response to Pollution Probe Interrogatory 10 has an undelivered energy column "LIE", which is not discounted, as labeled in the table. The difference between the two tables is that one value was adjusted to 2007 whereas the other one was not.

Pollution Probe INTERROGATORY #51 List 5

Interrogatory

Ref. Response Response to Pollution Probe Interrogatory #11 List 1 (Exh. C / T 2 / S 11)

Issue Number 1.0
1.0 Issue: Project Need and Justification

Request

a) Please provide all workpapers, including spreadsheets with formulas intact, used in computing the values in the response tables "Net Present Cost of Series Capacitors" for both the "OPA Discount Rate" version and the "Hydro One Discount Rate" version.
b) Please explain why the net present value of installing series capacitors includes a component of costs associated with undelivered energy.
c) Are the "losses" shown in the computation associated solely with the transmission system effect of the installation of series capacitors, or are they associated with the increased losses if the proposed Bruce – Milton double circuit 500 kV line is not installed, or are they associated with something else? If the "losses" are associated with something else, please explain what the losses are associated with.

Response

a) Hydro One and OPA have declined to answer this Interrogatory due to its confidential and commercial sensitivity. Please refer to correspondence on behalf of Hydro One dated March 13, 2008.

b) As indicated in the response to Pollution Probe Interrogatory 49, the cost associated with undelivered energy is the incremental cost of replacement energy. Therefore undelivered energy is a relevant cash flow considered in the net present cost calculation.

c) The "losses" cost has two components: energy losses and the capacity lost at system peak. Both components are measured relative to the Bruce to Milton option. Energy losses are assessed using a load flow which models the system with an average load of 22,400 MW. Losses at system peak are assessed with a load level of 28,000 MW.