Ontario Energy Board (Board Staff) INTERROGATORY #7 List 1

Issue 2 **Is the overall increase in 2013 and 2014 revenue requirement reasonable?**

Interrogatory

Ref: Exhibit A-13-1/ Appendix A
The Ontario CPI forecast from 2012 to 2016 averages 2.0% for each year. On page 2 under labour escalation, Hydro One uses assumptions of 3.0% for economic increases for Society, PWU and MCP staff for the same period. Why is 3.0% used when the evidence indicates a significantly lower forecast of inflation? Please provide an estimate of the cost savings achievable if a labour escalation rate of 2% is used for the test years.

Response

The labour escalation assumption used in the application was based on a number of factors listed in Exhibit I, Tab 7, Schedule 10.01 CCC23. To support the assumption, Hay Consulting is forecasting 2013 Bay Pay increases to be 2.9% (all organizations) and 3.1% (Utilities) and Mercer Consulting is forecasting 2013 Base Pay increases to be 3.2% (all industries) and 3.3% (utilities).

The estimate of the cost savings achievable if a labour escalation rate of 2% is used for the test years is $1.4M of OM&A each year and $1.6M and $1.7M of Capex in 2013 and 2014 respectively.

Vulnerable Energy Consumers Coalition (VECC)INTERROGATORY #22 List 1

Issue 3 **Is the load forecast and methodology appropriate and have the impacts of Conservation and Demand Management initiatives been suitably reflected?**

Interrogatory

Reference: Exhibit A, Tab 15, Schedule 2, Attachment I, pages 20-21 and 24-29

a) What adjustment for losses would need to be made to the MW values reported in Appendix A (pages 24-25) in order to make them consistent with the Billing Determinant values reported at Exhibit A, Tab 15, Schedule 2, page 21, Table 3?

b) Please confirm whether Table 8 (page 25 of Attachment I) sets out the actual demand response program MWs under contract and available at the time of system peak for the years 2006-2011 or the MWs by which the peak load in each year was actually reduced through the use of demand response programs.

c) If the former, by how much was the system peak in each year (2006-2011) actually reduced through the use of load management/demand response programs?

d) If the latter, what were the MWs of demand response under contract for each year 2006-2011?

e) In what months of each year (2006-2011) were the MW under contract for load management/demand response activated?

f) Do the forecasts for CDM impacts on Ontario demand (as shown in Table 3) assume that the MWs available from demand response programs have been activated and used to reduce:

i) The System Peak, and/or
ii) The Peak in each Month

If yes, what is the basis for this assumption and please re-do Table 3 (page 21) excluding the impact of demand response programs.

g) With respect to Appendix B (Monthly COM Impacts). please provide a schedule that sets out the Monthly Demand Savings for 2012-2014 by resource type.

Response

a) The MW values reported in Exhibit A, Tab15, Schedule 2, Attachment 1, Appendix A, pages 24-25, pertain to the maximum peak reduction in a year at the generation level, while the MW values reported in Exhibit A, Tab 15, Schedule 2, page 21, Table 3, pertain to the 12-month average peak for the whole year at the wholesale purchase level applicable to Hydro One. The loss adjustment between the generation level and the wholesale purchase level is the transmission loss. Hydro One uses the following loss assumptions provided by the OPA for adjustments from the generation level to the wholesale level.

Losses Assumption	Assumption 2006-2010	Assumption 2011-2014
Transmission	2.70%	2.50%

b) The impact from demand response (DR) programs in the historical period is considered to be actual demand reduction.

c) Refer to the response to (b).

d) Hydro One did not get this information from the OPA.

e) Hydro One did not get this information from the OPA.

f) Yes, the forecast for CDM impacts on Ontario demand assumes that the MWs available from DR programs have been activated and used to reduce both (i) the system peak and (ii) the peak in each month.

Hydro one calculated the DR monthly impact using the DR annual impact and DR hourly load shapes provided by the OPA.

The requested table (assuming no DR) is provided below:

Annual CDM impacts by charge determinant
(12-month average peak MW)

Year	Ontario Demand	Network Connection	Line Connection	Transformation Connection
2012	1351	1331	1239	996
2013	1599	1565	1457	1172
2014	2139	2108	1962	1577

g) The monthly demand savings for 2012-2014 by resource type (at the end-use level) are provided below:

By Resource Type	Month	2012	2013	2014
Demand Response	1	617	712	766
Demand Response	2	144	144	146
Demand Response	3	144	144	146
Demand Response	4	420	144	832
Demand Response	5	420	144	832
Demand Response	6	924	1,083	1,211
Demand Response	7	924	1,083	1,211
Demand Response	8	924	1,083	1,211
Demand Response	9	420	473	508
Demand Response	10	144	144	146
Demand Response	11	363	417	775
Demand Response	12	626	722	775
Energy Efficiency	1	1,236	1,381	1,801
Energy Efficiency	2	1,180	1,340	1,789
Energy Efficiency	3	1,102	1,256	1,675

By Resource Type	Month	2012	2013	2014
Energy Efficiency	4	1,036	1,274	1,728
Energy Efficiency	5	1,154	1,371	1,884
Energy Efficiency	6	1,512	1,848	2,512
Energy Efficiency	7	1,646	1,996	2,708
Energy Efficiency	8	1,514	1,831	2,478
Energy Efficiency	9	1,369	1,655	2,236
Energy Efficiency	10	1,085	1,254	1,696
Energy Efficiency	11	1,145	1,292	1,717
Energy Efficiency	12	1,201	1,360	1,814
Customer Based Generation	1	9	8	7
Customer Based Generation	2	8	8	7
Customer Based Generation	3	8	7	7
Customer Based Generation	4	7	7	7
Customer Based Generation	5	8	8	8
Customer Based Generation	6	11	11	11
Customer Based Generation	7	12	12	12
Customer Based Generation	8	11	10	10
Customer Based Generation	9	9	9	9
Customer Based Generation	10	7	7	7
Customer Based Generation	11	8	7	7
Customer Based Generation	12	8	8	7

Ontario Energy Board (Board Staff) INTERROGATORY #58 List 1

Issue 12 Are the proposed 2013 and 2014 Sustaining and Development and Operations capital expenditures appropriate, including consideration of factors such as system reliability and asset condition?

Interrogatory

Ref: Exhibit D1/Tab3/Sch2/p 15 and ISD # S6 Hanmer TS – 500kV ABCB; ISD # S9 Hanmer TS ABCB Re-investment in EB-2010-0002

a) The description of the project in ISD # S6 in the current application appears to be very similar to the description of the project in ISD# S9 in EB-2010-0002. Please clarify if the Hanmer TS ABCB project in the current application is a new project or if it is the same project (ISD# S9) for which Hydro One received Board approval in EB-2010-0002.

b) Is the project as proposed in EB-2010-0002, on schedule to be placed in-service in "Late 2012"? If there is a possibility that the project may be delayed, please provide the reasons for the delay and provide the new in-service date.

c) Please also provide a brief description of the work that was performed in 2011/2012 and a high level cost breakdown for this work.

d) If the projects in part (a) are the same project, please explain the reasons for the additional expenditure (i.e. in addition to the $18.8 million proposed in EB-2010-0002) of $7.5 million in the current application. Please provide a brief description of the work that will be undertaken in 2013/2014 and a high level cost breakdown for this work.

Response

a) Yes, they are the same project.

b) The project is planned to be placed in-service in 2013. The in-service delay is due to the failure of the Hanmer T6 500kV autotransformer in February 2012, which had an impact on the planned outages required for the staging of the re-investment work identified in ISD #S6 in the current application.

c) The planned project costs through year end 2012 are $18.6 million, and include engineering/design, equipment procurement, and some construction activity.

d) The $18.8 million proposed in EB-2010-0002 was the sum of the 2011 and 2012 test year capital expenditure only, and did not include expenditures outside of the test years. This convention was consistently applied for all Sustaining Capital project or program work in the EB-2010-0002 application.

An adapted convention has been applied in this application to be consistent with other areas of Development and Operations Capital. For the Project work, the ‘Total Cost’ in Exhibit D1, Tab 3, Schedule 2 and Exhibit D2, Tab 2, Schedule 3 includes all project costs from historic, bridge, test, and future years. Whereas Program work which is on-going in nature, the ‘Total Cost’ in Exhibit D1, Tab 3, Schedule 2 and Exhibit D2, Tab 2, Schedule 3 remains as the sum of the test year expenditures only.

The remaining planned capital expenditure on the project beyond 2012 is $7.5 million to complete remaining construction and commissioning work in achieving the scope defined in ISD #S6 of the current application.

Ontario Energy Board (Board Staff) INTERROGATORY #59 List 1

Issue 12 **Are the proposed 2013 and 2014 Sustaining and Development and Operations capital expenditures appropriate, including consideration of factors such as system reliability and asset condition?**

Interrogatory

Ref: Exhibit D1/Tab3/Sch2/p 15 and ISD # S7 Orangeville TS – 230kV ABCB Replacement; ISD # S7 Orangeville TS ABCB Re-investment in EB-2010-0002
The Board approved the Orangeville TS ABCB Re-investment project in EB-2010-0002. This project is expected to be in-service in 2013. In EB-2010-0002, the project (gross) costs were stated to be $23 million with a proposed expenditure of $10.3 million and $10.6 million in 2011 and 2012 respectively. In the current application, Hydro One is proposing to spend additional capital of $ 9 million in the test years.

a) Please provide reasons for the additional spending that is proposed in 2013.

b) Please provide a description of the work undertaken in 2011 and 2012 and the work that will be undertaken in 2013 and 2014. Please provide a high level cost breakdown for the work done in 2011 and 2012 and the work expected to be done in 2013 and 2014.

Response

a) The $22.9 million proposed in EB-2010-0002 was the sum of the 2011 and 2012 test year capital expenditure only, as explained in Exhibit I, Tab 12, Schedule 1.05 Staff 58.

   The total project cost in Exhibit D1, Tab 3, Schedule 2 and Exhibit D2, Tab 2, Schedule 3 includes all project costs from historic, bridge, test, and future years, as explained in Exhibit I, Tab 12, Schedule 1.05 Staff 58.

   The remaining planned capital expenditure on the project beyond 2012 is $8.9 million to complete remaining construction and commissioning work in achieving the scope defined in ISD #S7 of the current application.

b) The planned project expenditures through year end 2012 are $19.2 million, and include engineering/design and equipment procurement for the majority of the project. Also included are construction and commissioning work for a portion of the project which is planned to be in-service in 2012.

The remaining planned capital expenditure on the project in 2013 and 2014 is $8.9 million to complete remaining construction and commissioning work in achieving the scope defined in ISD #S7 of the current application.

Ontario Energy Board (Board Staff) INTERROGATORY #60 List 1

Issue 12 **Are the proposed 2013 and 2014 Sustaining and Development and Operations capital expenditures appropriate, including consideration of factors such as system reliability and asset condition?**

Interrogatory

Ref: Exhibit D1/Tab3/Sch2/p 14 &15 and ISD # S8 Pickering A SS – 230kV ABCB; ISD # S10 Pickering A switchyard: ABCB Re-Investment in EB-2010-0002

a) Please clarify if the project described at ISD# S8 in the current application is a new project or the same project for which Hydro One received Board approval (ISD#10) in EB-2010-0002.

b) Is the project as proposed in EB-2010-0002 on schedule to be placed in-service in 2012? If there is a possibility that the project may be delayed, please provide the reasons for the delay and provide the new in-service date.

c) Please provide a brief description of the work that was performed in 2011/2012 and a high level cost breakdown of this work.

d) If the projects in part (a) are the same project, please explain the reasons for the additional expenditure (i.e. in addition to the $7.3 million proposed in EB-2010-0002) of $6.8 million in the current application. Please provide a brief description of the work that will be undertaken in 2013/2014 and a high level cost breakdown for this work.

Response

a) Yes, they are the same project.

b) The entire project will be completed and in-service by 2014, however portions will be completed and placed in-service in each year 2011 through 2014. Hydro One's project staging plan is coordinated with OPG and the IESO, and aligns with the planned outages of the Pickering generators.

Note, there is a typographical error in ISD#8, the In-Service Date should be 2014.

c) The planned project costs through year end 2012 are $4.8 million, and include engineering/design, equipment procurement, and some construction and commissioning activity. Two of the four breaker replacements will be completed and in-service by the end of 2012.

d) The $7.3 million proposed in EB-2010-0002 was the sum of the 2011 and 2012 test year capital expenditure only as explained in Exhibit I, Tab 12, Schedule 1.05 Staff 58

The total project cost in Exhibit D1, Tab 3, Schedule 2 and Exhibit D2, Tab 2, Schedule 3 include all project costs from historic, bridge, test, and future years as explained in Exhibit I, Tab 12, Schedule 1.05 Staff 58.

The remaining planned capital expenditure on the project beyond 2012 is $6.8 million to complete remaining construction and commissioning work in achieving the scope defined in ISD #S8 of the current application. The final two circuit breakers and their associated equipment will be replaced, and the two breakers which are no longer required due to the shutdown of G2 and G3 at Pickering A NGS will be bypassed and physically removed.

Ontario Energy Board (Board Staff) INTERROGATORY #61 List 1

Issue 12 **Are the proposed 2013 and 2014 Sustaining and Development and Operations capital expenditures appropriate, including consideration of factors such as system reliability and asset condition?**

Interrogatory

Ref: Exhibit D1/Tab3/Sch2/p. 15 and ISD # S9 Richview TS – 230 kV ABCB; ISD # S8 Richview TS ABCB Re-investment in EB-2010-0002

a) The description of the project in ISD # S9 in the current application appears to be similar to the description of the project in ISD# S8 in EB-2010-0002. Please clarify if the project in the current application is a new project or if it is the same project (ISD# S8) for which Hydro One received Board approval in EB-2010-0002.

b) Is the project as proposed in EB-2010-0002 on schedule to be placed in-service in Late 2012? If there is a possibility that the project may be delayed, please provide the reasons for the delay and provide the new in-service date.

c) Please provide a brief description of the work that was undertaken in 2011/2012 and a high level cost breakdown for this work.

d) If the two projects in part (a) are the same, please provide the reasons for the significant increase in project cost from $17.1 million in EB-2010-0002 to $61.2 million in this current application. Please provide a brief description of the work that will be undertaken in 2013/2014 and a high level cost breakdown for this work.

Response

a) Yes, they are the same project.

b) The project is now scheduled to be in-service in 2017, whereas in the project presented in the EB-2010-002 proceeding had project expenditures going in-service in 2014.

   The shift in schedule is primarily driven by outage planning constraints in the Toronto area. Currently there is major Development Capital work being undertaken at Leaside, Manby, and Hearn (projects from ISD#s D7, D8, and D9 respectively) which restricts further outages in the Toronto area.

c) The planned project costs through year end 2012 are $0.2 million for preliminary engineering/design.

d) The $17.1 million proposed in EB-2010-0002 was the sum of the 2011 and 2012 test year capital expenditure only, as explained in Exhibit I, Tab 12, Schedule 1.05 Staff 58.

The total project cost in Exhibit D1, Tab 3, Schedule 2 and Exhibit D2, Tab 2, Schedule 3 includes all project costs from historic, bridge, test, and future years, as explained in Exhibit I, Tab 12, Schedule 1.05 Staff 58.

The remaining planned capital expenditure on the project beyond 2012 is $61.0 million to complete remaining engineering/design, procurement, construction, and commissioning work in achieving the scope defined in ISD #S9 of the current application.

Ontario Energy Board (Board Staff) INTERROGATORY #63 List 1

Issue 12 **Are the proposed 2013 and 2014 Sustaining and Development and Operations capital expenditures appropriate, including consideration of factors such as system reliability and asset condition?**

Interrogatory

Ref: Exhibit D1/Tab3/Sch2/p 16 – End of Life Reconfiguration Projects and ISD# S13 – Abitibi Canyon SS/ Pinard TS: Reconfiguration and Demerge; ISD# S5 Abitibi Canyon SS and Pinard TS - Replace Oil Circuit Breakers (OCB) and other EOL Components, in EB-2010-0002

a) The description of the Abitibi Canyon/Pinard TS project in ISD # S13 in the current application and in ISD # S5 in EB-2010-0002 appears to be very similar. Please clarify if the project described at ISD# S13 in the current application is a new project or if it is the same project for which Hydro One received approval in (ISD# S5) EB-2010-0002.

b) Is the project as proposed in EB-2010-0002 on schedule to be placed in-service in 2012? If there is a possibility that the project may be delayed, please provide the reasons for the delay and provide the new in-service date.

c) Please provide a brief description of the work that was performed in 2011/2012 and a high level cost breakdown for this work.

d) If the projects in part (a) are the same project, please explain the reason for the significant increase in the project cost, from $21.7 million in EB-2010-0002, to $47 million in this current application. Please provide a description of the work that will be undertaken in 2013/2014 and a high level cost breakdown for this work.

Response

a) Yes, they are the same project.

b) The project is planned to be completed and placed in-service in 2013. This updated timeline is reflective of the detailed project planning that has been completed.

The delay is detailed in Exhibit D1, Tab 3, Schedule 2, page 16.

c) The planned project costs through year end 2012 are $23.0 million, and include engineering/design, equipment procurement, and some construction activity.

d) The $21.7 million proposed in EB-2010-0002 was the sum of the 2011 and 2012 test year capital expenditure only, as explained in Exhibit I, Tab 12, Schedule 1.05 Staff 58.

The total project cost in Exhibit D1, Tab 3, Schedule 2 and Exhibit D2, Tab 2, Schedule 3 includes all project costs from historic, bridge, test, and future years as explained in Exhibit I, Tab 12, Schedule 1.05 Staff 58.

The remaining planned capital expenditure on the project beyond 2012 is $24.0 million to complete remaining construction and commissioning work in achieving the scope defined in ISD #S13 of the current application.

<u>Ontario Energy Board (Board Staff) INTERROGATORY #66 List 1</u>

Issue 12 **Are the proposed 2013 and 2014 Sustaining and Development and Operations capital expenditures appropriate, including consideration of factors such as system reliability and asset condition?**

<u>Interrogatory</u>

Ref: Exhibit D1/Tab3/Sch2/p 17 and ISD# S14 Beck # 1 SS – Build New Switchyard; ISD #S4 in EB-2010-0002

At Exhibit D1/Tab3/Sch2/p 17, (lines 7 -17), Hydro One states "Beck # 1SS Reconfiguration was identified in EB-2010-0002 as project S4".

a) Please clarify if the project described at ISD# S14 in the current application is a new project or is it the same project for which Hydro One received approval in EB-2010-0002?

b) This project was expected to be in-service in 2012 and appears that it may be delayed to 2016/2017. Please provide a high level cost breakdown of the work that was undertaken in 2011 and 2012.

c) Please explain the reason for the significant increase in the project cost, from $47 million in 2012 to $83.4 million in the current application.

<u>Response</u>

a) Yes, they are the same project.

b) The planned project expenditures through year end 2012 are $0.7 million for preliminary engineering/design. Explanation for the project delay is provided in Exhibit D1, Tab 3, Schedule 2 on page 16.

c) The $47.5 million proposed in EB-2010-0002 was the sum of the 2011 and 2012 test year capital expenditure only, as explained in Exhibit I, Tab 12, Schedule 1.05 Staff 58.

   The total project cost in Exhibit D1, Tab 3, Schedule 2 and Exhibit D2, Tab 2, Schedule 3 includes all project costs from historic, bridge, test, and future years, as explained in Exhibit I, Tab 12, Schedule 1.05 Staff 58.

   The remaining planned capital expenditure on the project beyond 2012 is $82.7 million to complete remaining engineering/design, procurement, construction, and commissioning work in achieving the scope defined in ISD #S14 of the current application.