Hydro One Networks Inc.
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Susan Frank
Vice President and Chief Regulatory Officer
Regulatory Affairs

BY COURIER

November 12, 2012

Ms. Kirsten Walli
Ontario Energy Board
Suite 2700, 2300 Yonge Street
Toronto, ON.
M4P 1E4

Dear Ms. Walli:

EB-2012-0031 – Hydro One Networks' 2013 and 2014 Transmission Revenue Requirement Application – Hydro One Updates to Prefiled Evidence and Interrogatory Responses

As per the Board's Decision and Order on November 8, 2012, Hydro One Networks has updated the evidentiary record to remove all references to the CEA Transmission COPE 2011 Comprehensive Annual Report. Attached are ten (10) copies of the blue page updates for the following evidence.

Exhibit A, Tab 13, Schedule 02	Update pages 28-29
Exhibit A, Tab 17, Schedule 01	Update pages 1, 11
Exhibit I, Tab 07, Schedule 3.08 EP 34	Update page 1

Also the following exhibits have been removed from the evidence in their entirety.

Exhibit I, Tab 02, Schedule 9.03 SEC 3;
Exhibit I, Tab 05, Schedule 9.11 SEC 18;
Exhibit I, Tab 07, Schedule 3.12 EP 38;

The Board also ordered Hydro One to provide Goldcorp with a continuity schedule of the Net Book Value from 2006 to 2011 at the Uniform System of Account detail for the Red Lake TS station. A copy of this schedule is also attached.

An electronic copy of the updated evidence have been filed using the Board's Regulatory Electronic Submission System (RESS) and the confirmation of successful submission slip is provided with this letter.

Sincerely,
ORIGINAL SIGNED BY SUSAN FRANK

Susan Frank

Attach.
cc. EB-2012-0031 Intervenors (electronic only)

Hydro One Networks Inc.
2006 to 2011 Continuity Schedule of the Net Book Value for the Red Lake TS

Amounts in $'000	2006	2007	2008	2009	2010	2011
Red Lake TS - NBV Opening						
1705 - Land	3	3	3	3	3	3
1708 - Buildings & Fixtures	553	537	549	534	478	463
1715 - Station Equipment	5,704	5,524	10,802	13,088	12,267	13,799
1745 - Roads & Trails	0	0	295	431	438	473
Total NBV Opening	**6,260**	**6,065**	**11,649**	**14,056**	**13,187**	**14,738**
Add: Net Additions						
1705 - Land	0	0	0	0	0	0
1708 - Buildings & Fixtures	0	0	0	0	0	0
1715 - Station Equipment	0	5,501	2,676	187	1,988	63
1745 - Roads & Trails	0	297	141	13	39	1
Total Net Additions	**0**	**5,798**	**2,817**	**200**	**2,027**	**64**
Less: Depreciation						
1705 - Land	0	0	0	0	0	0
1708 - Buildings & Fixtures	-16	11	-15	-56	-15	-15
1715 - Station Equipment	-179	-224	-390	-1,007	-456	-410
1745 - Roads & Trails	0	-1	-5	-6	-5	-5
Total Depreciation	**-195**	**-214**	**-410**	**-1,069**	**-475**	**-429**
Red Lake TS - NBV Closing						
1705 - Land	3	3	3	3	3	3
1708 - Buildings & Fixtures	537	549	534	478	463	449
1715 - Station Equipment	5,524	10,802	13,088	12,267	13,799	13,452
1745 - Roads & Trails	0	295	431	438	473	469
Total NBV Closing	**6,065**	**11,649**	**14,056**	**13,187**	**14,738**	**14,373**

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BY COURIER

October 24, 2012

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

Dear Ms. Walli:

EB-2012-0031 – Hydro One Networks' 2013 and 2014 Transmission Revenue Requirement Application – Hydro One Response to SEC Motion and Update to Interrogatory Responses

In response to the Board's decision on the SEC Notice of Motion filed October 17, 2012, I am attaching updated response to the following Interrogatories:

Exhibit I, Tab 11, Schedule 9.01 SEC 24
Exhibit I, Tab 12, Schedule 9.03 SEC 27

The Power Planner 4th Quarter 2011 Report prepared by IHS Global Insight released in February 2012 has been filed at, Exhibit I, Tab 12, Schedule 9.03 SEC 27, Attachment 1, pursuant to the Board's Practice Direction on Confidential Filings. Hydro One will provide a copy of the confidential filing with intervenors who have signed the Board's confidential undertaking form. The response to SEC Interrogatory #27 provides a summary of the report.

An electronic copy of the Interrogatories have been filed using the Board's Regulatory Electronic Submission System.

Sincerely,

ORIGINAL SIGNED BY SUSAN FRANK

Susan Frank

Attach.

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BY COURIER

October 19, 2012

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

Dear Ms. Walli:

EB-2012-0031 – Hydro One Networks' 2013 and 2014 Transmission Revenue Requirement Application – JT1.2, Technical Conference Undertakings and Interrogatory Responses Updates

Consistent with the discussion at the Technical Conference, I am attaching two (2) copies of Hydro One Networks Inc.'s ("Hydro One") written responses to the Technical Conference Questions listed below. The responses filed today were given the Exhibit number JT1.2 during the Technical Conference.

Intervenor	**Question Numbers**
Energy Probe	1, 3, 5, 6, 8, 9

Also attached are two (2) copies of Hydro One's responses to the following Technical Conference Undertakings.

KT1.1	KT1.2	KT1.3	KT1.4	KT1.5	KT1.6
KT1.7	KT1.8	KT1.9	KT1.10	KT1.11	KT1.12
KT1.13	KT1.14	KT1.15	KT1.16	KT1.17	KT1.23
KT1.24	KT1.25	KT1.26	KT1.27	KT1.28	KT1.29
KT1.30	KT1.31	KT1.32	KT1.33	KT1.34	KT1.35
KT1.36					

As to Goldcorp's questions from the Technical Conference KT1.18, KT 1.19, KT1.20, KT1.21, KT1.22, upon further review of those questions, it is clear that none of Goldcorp's questions are pertinent to Hydro One's transmission revenue requirement, rates or other charges for the transmission of electricity in 2013 and 2014. Hydro One submits, therefore, that the current rate proceeding is not the appropriate forum to address those questions.

Also attached are ten (10) copies of the blue page update responses for the following interrogatories.

Exhibit I, Tab 02, Schedule 1.06 Staff 7;
Exhibit I, Tab 03, Schedule 5.08 VECC 22;
Exhibit I, Tab 12, Schedule 1.05 Staff 58;
Exhibit I, Tab 12, Schedule 1.06 Staff 59;
Exhibit I, Tab 12, Schedule 1.07 Staff 60;
Exhibit I, Tab 12, Schedule 1.08 Staff 61;
Exhibit I, Tab 12, Schedule 1.10 Staff 63;
Exhibit I, Tab 12, Schedule 1.13 Staff 66;

An electronic copy of the responses have been filed using the Board's Regulatory Electronic Submission System (RESS) and the confirmation of successful submission slip is provided with this letter.

Sincerely,

ORIGINAL SIGNED BY SUSAN FRANK

Susan Frank

Attach.

cc. EB-2012-0031 Intervenors (electronic only)

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BY COURIER

October 5, 2012

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

Dear Ms. Walli:

EB-2012-0031 – Hydro One Networks' 2013 and 2014 Transmission Revenue Requirement Application – Hydro One Response to APPrO Motion and Update to Interrogatory Responses

In response to the APPrO Notice of Motion filed on September 28, 2012, I am attaching updated responses for the following interrogatories respecting Issue 23.

Exhibit I, Tab 23, Schedule 11.02 APPrO 2;
Exhibit I, Tab 23, Schedule 11.04 APPrO 4;
Exhibit I, Tab 23, Schedule 11.05 APPrO 5; and
Exhibit I, Tab 23, Schedule 11.07 APPrO 7.

An electronic copy of the Interrogatories have been filed using the Board's Regulatory Electronic Submission System.

Sincerely,

ORIGINAL SIGNED BY SUSAN FRANK

Susan Frank

Attach.

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Susan Frank
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BY COURIER

September 20, 2012

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

Dear Ms. Walli:

EB-2012-0031 – Hydro One Networks' 2013 and 2014 Transmission Revenue Requirement Application – Hydro One Networks Responses to Interrogatory Questions and Update to A-8-3

Please find attached an electronic copy of responses provided by Hydro One Networks to Interrogatory questions and an update to Exhibit A, Tab 8, Schedule 3. Ten (10) hard copies will be sent to the Board shortly.

The Interrogatory Responses have been filed by Issue. Below is the Tab numbers for each Issue:

Tab 1	Issue 1 Has Hydro One responded appropriately to all relevant Board directions from previous proceedings?
Tab 2	Issue 2 Is the overall increase in 2013 and 2014 revenue requirement reasonable?
Tab 3	Issue 3 Is the load forecast and methodology appropriate and have the impacts of Conservation and Demand Management initiatives been suitably reflected?
Tab 4	Issue 4 Are Other Revenue (including export revenue) forecasts appropriate?
Tab 5	Issue 5 Are the proposed spending levels for Sustaining, Development and Operations OM&A in 2013 and 2014 appropriate, including consideration of factors such as system reliability and asset condition?
Tab 6	Issue 6 Are the proposed spending levels for Shared Services and Other O&M in 2013 and 2014 appropriate?
Tab 7	Issue 7 Are the 2013/14 Human Resources related costs (wages, salaries, benefits, incentive payments, labour productivity and pension costs) including employee levels appropriate? Has Hydro One demonstrated improvements in efficiency and value for dollar associated with its compensation costs?
Tab 8	Issue 8 Are the methodologies used to allocate Shared Services and Other O&M costs to the transmission business and to determine the transmission overhead capitalization rate for 2013/14 appropriate?
Tab 9	Issue 9 Are the amounts proposed to be included in the 2013 and 2014 revenue requirements for income and other taxes appropriate?
Tab 10	Issue 10 Is Hydro One Networks' proposed depreciation expense for 2013 and 2014 appropriate?
Tab 11	Issue 11 Are the amounts proposed for rate base in 2013 and 2014 appropriate?

Tab 12	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?
Tab 13	Issue 13 Are the proposed 2013 and 2014 levels of Shared Services and Other Capital expenditures appropriate?
Tab 14	Issue 14 Are the methodologies used to allocate shared services and other capital expenditures to the transmission business, appropriate?
Tab 15	Issue 15 Are the inputs used to determine the working capital component of the rate base and the methodology used appropriate?
Tab 16	Issue 16 Does Hydro One's Asset Condition Assessment information and Investment Planning Process adequately address the condition of the transmission system assets and support the O&MA and Capital expenditures for 2013/14?
Tab 17	Issue 17 Is the proposed timing and methodology for determining the return on equity and short- term debt prior to the effective date of rates appropriate?
Tab 18	Issue 18 Is the forecast of long term debt for 2012-2014 appropriate?
Tab 19	Issue 19 Are the proposed amounts, disposition and continuance of Hydro One's existing Deferral and Variance accounts appropriate?
Tab 20	Issue 20 Are the proposed new Deferral and Variance Accounts appropriate?
Tab 21	Issue 21 Is the cost allocation proposed by Hydro One appropriate?
Tab 22	Issue 22 Are the OM&A and capital amounts in the Green Energy Plan appropriate and based on appropriate planning criteria?
Tab 23	Issue 23 What is the appropriate level for Export Transmission Rates in Ontario?
Tab 24	Issue 24 Are the proposed modifications to the Hydro One transmission connection procedures appropriate?
Tab 25	Issue 25 Have all impacts of the conversion of regulatory and financial accounting from CGAAP to USGAAP been identified, and reflected in the appropriate manner in the Application, the revenue requirement for the Test Years and the proposed rates?

An electronic copy of the Interrogatories and the updated exhibit, have been filed using the Board's Regulatory Electronic Submission System.

Sincerely,

ORIGINAL SIGNED BY SUSAN FRANK

Susan Frank
Attach.

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

Issue 1 Has Hydro One responded appropriately to all relevant Board directions from previous proceedings?

Interrogatory

1.0-Staff-1
Ref: Exhibit A/Tab 6/Sch1
Hydro One mentions that the application satisfies the Filing Requirements and Handbook requirements except where it was not practical or appropriate to do so based on previous comments and direction from the Board, or as a result of specific government regulation. Please provide a brief summary of where the Filing Requirements and Handbook requirements are not satisfied and the rationale for each item or area.

Response

As noted in the Pre-filed Evidence (EB-2012-0031), the Application is substantially consistent with Chapter 2 of the Board's Filing Requirements for Transmission and Distribution Applications dated June 28, 2012. Departures are provided in the following table.

No.	Exhibit[1]	Item	Explanation
1	Rate Base	Continuity statements should be reconciled to the calculated depreciation expenses and presented by asset account (Ref.: 2.5.1.3 Accumulated Depreciation)[1]	Largely provided at D2-3-1 and D2-3-2 except for "by asset account"
2	Operating Costs	Breakdown of total salaries, wages, benefits charged to OM&A (Ref.: 2.7.4 Employee Compensation Breakdown)[1]	Hydro One adopts the work-based approach, which does not allow for the split out of Transmission specific information
3	Operating Costs	Purchase of Non-Affiliate Services (Ref.: 2.7.6 Purchase of Non-Affiliate Services)[1]	Not practical given the volume and number of monthly transactions and Hydro One's work-based approach.

No.	Exhibit[1]	Item	Explanation
4	Operating Costs	Depreciation, Amortization and Depletion "by asset group" for Historical, Bridge and Test Years (Ref.: 2.7.7 Depreciation/Amortization/Depletion)[1]	Could provide upon request.
5	Revenue Deficiency /Sufficiency	Calculation of revenue deficiency or sufficiency and summary of the drivers of the test year deficiency/sufficiency (Ref.: 2.9 Calculation of Revenue Deficiency or Sufficiency)	Hydro One has not been asked to provide this calculation in previous transmission rate applications; however, it could be provided upon request.

[1] OEB's Chapter 2 of the Filing Requirements for Transmission and Distribution Applications amended on June 28, 2012

Ontario Energy Board (Board Staff) INTERROGATORY #2 List 1

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

Interrogatory

Ref: Exhibit A/Tab 4/Sch 1/p 11
Hydro One mentions that it is a bidder through its one-third interest in the East-West Tie partnership. Please provide the background information on how the cost of this bid is treated by Hydro One. How does or will this bid impact Hydro One's transmission or distribution businesses?

Response

Hydro One has requested a deferral account "External Revenue – Partnership Transmission Project Account" (Exhibit F1, Tab 1, Schedule 2, page 5) to record costs for services provided by Hydro One Networks staff who participated, or were involved in the preparation of the EWT LP's designation plan, in respect of the Board's East-West Tie transmitter designation proceeding (EB-2011-0140). For further information on this deferral account please see Exhibit I, Tab 20, Schedule 1.01 Staff 81.

There is no impact on Hydro One Networks' 2013 transmission revenue requirement or business in relation to supporting the bid of EWT LP. For 2014, if EWT LP is the winning bidder, at this point Hydro One does not anticipate that Networks staff will be used significantly for any work on behalf of EWT LP occurring in 2014. Hence there will be no or minimal impact on Networks' 2014 transmission revenue requirement or business as well. If any work is performed for EWT LP, it would be invoiced to EWT LP at the fully loaded rate Hydro One uses for the costing of work and recorded in the deferral account. Hydro One does not believe this will involve any significant amount of work.

The same applies to the Hydro One Distribution revenue requirement and business.

Ontario Energy Board (Board Staff) INTERROGATORY #3 List 1

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

Interrogatory

Ref: Exhibit A/Tab 4/Sch1/pp 12 & 13
Under the section entitled North American Reliability Framework, Hydro One provides an overview of its obligations under the framework and mentions that 60 of the 120 standards apply to Hydro One. What is the status of Hydro One's compliance with these standards? Where, in this application do the bulk of the costs of compliance fall and are costs falling or growing into the test years?

Response

Hydro One's policy is to comply with the requirements set out in applicable reliability standards. Hydro One deploys mitigation measures to address any compliance gaps in concurrence with the reliability authority, the Independent Electricity System Operator (IESO) in Ontario.

In recent years, most of the costs of complying with reliability standards have been O&M; some capital investments have also been required to comply with new Critical Infrastructure Protection (CIP) Standards. These OM&A and Capital costs are embedded within the relevant programs. The O&M costs associated with the standards have been gradually increasing and are expected to continue to increase, as new versions of reliability standards with more stringent requirements become effective.

The approval (and potential refinement) of the BES definition by NERC is still in process. Currently, less than 10% of Hydro One's transmission assets are required to comply with BES mandatory reliability requirements. Under the new proposed BES definition, the percentage may increase to 25%. The new definition may also result in capital expenditure beyond the test years. In the test years, we expect these impacts to be primarily O&M related costs and these costs have not been included in this application because the definition has not yet been finalized. Depending on the definition approval and implementation timelines, O&M costs will grow and will be incremental in the test years. Hydro One expects that the Ontario BES Exception Procedure being developed by the IESO will help mitigate these cost increases.

Ontario Energy Board (Board Staff) INTERROGATORY #4 List 1

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

Interrogatory

Ref: Exhibit A/Tab 2/Sch1/p 1
At this reference, Hydro One indicates that the rates revenue requirement will increase by 0.6% in 2013 and 9.0% in 2014. Please provide the detailed calculation of these percentage increases, with reference to Exhibit E1/Tab1/Schedule1.

Response

Hydro One notes that the revenue requirement shown in Exhibit A, Tab 2, Schedule 1, page 1, was updated on August 15th. The updated revenue requirement impacts are 0.6% in 2013 and 9.1% in 2014.

The information shown below up to Rates Revenue Requirement is included in Table 2 and Table 4 of the pre-filed evidence at Exhibit E1, Tab 1, Schedule 1.

	2012	2013	2014
OM&A		453.3	459.7
Depreciation		346.7	374.7
Income tax		46.4	55.2
Cost of Capital		618.1	668.1
Revenue Requirement	**1,418.4**	**1,464.5**	**1,557.7**
Increase over prior year		**3.3%**	**6.4%**
Less: External Revenues		-31.6	-31.8
Less: Export Revenue Credit		-31.0	-30.1
Less: Regulatory Accounts Disposition		-15.1	-15.1
Add: Low Voltage Switchgear (LVSG)		11.7	12.5
Rates Revenue Requirement	**1,385.1**	**1,398.5**	**1,493.1**
Increase over prior year		**1.0%**	**6.8%**
Revenue impact of load forecast change		-0.4%	2.3%
Rates Revenue Requirement Impact		**0.6%**	**9.1%**

Ontario Energy Board (Board Staff) INTERROGATORY #5 List 1

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

Interrogatory

Ref: Exhibit A/Tab 2/Sch 1/p 1
Please provide the detailed background calculations used to derive the quoted average customer's total bill increase of 0.0% in 2013 and 0.7% in 2014.

Response

The average customer's total bill impact of 0.0% in 2013 and 0.7% in 2014 is based on the assumption that Transmission charges represent 7.9% of the total bill.

The 7.9% assumption is based on the following information:

Transmission as a % of Total Electricity Market Costs (2011)

		¢/kWh	Source
Commodity		7.195	IESO December 2011 Monthly Market Report page 20
Wholesale Market Service Charges		0.518	IESO December 2011 Monthly Market Report page 20
Wholesale Transmission Charges	*(A)*	0.933	IESO December 2011 Monthly Market Report page 20
Debt Retirement Charge		0.700	IESO December 2011 Monthly Market Report page 20
Distribution Service Charges		2.52	$3.052 B / 121.2 TWh delivered per 2010 OEB Yearbook page 7 and 10
Total	*(B)*	11.86	
Transmission as a % of Total	*(A/B)*	**7.9%**	

Since the Rates Revenue Requirement will increase by 0.6% in 2013 and 9.1% in 2014 (as per Exhibit A, Tab 2, Schedule 1, page 1); applying the assumption that transmission is about 7.9% of the total bill results in an estimated increase in total bill of 0.047% (rounded to 0.0%) for 2013 and 0.7% for 2014.

Ontario Energy Board (Board Staff) INTERROGATORY #6 List 1

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

Interrogatory

Ref: ExhibitA-13-1/AppendixA
At this reference, Hydro One shows the 2012 Business Planning Assumptions. The Forecasts mentioned are quite dated, for instance:

- Ontario-CPI forecasts are dated Apri12011.
- Bond Rate forecast is dated October 2011.
- 90-day Banker's Acceptance Rate forecast is dated June 2011.
- 10 year Government of Canada Forecast and the DEX mid-term spread are both dated October 2011.

It appears from the evidence at Exhibit A/Tab15/Schedule1 that more recent forecasts are available. Why were more recent forecasts not used for this section of the application? Please provide an update for the quoted sources and the impact of these updates on the application.

Response

The business planning assumption appendix details the costing assumptions available at the time the business planning instructions were issued as illustrated in Exhibit A, Tab 13, Schedule 1, Page 2. The intent of the appendix is to document Hydro One's initial assumptions in developing the plan. Costing assumptions are updated throughout the planning process where possible.

Below is an update for the quoted sources with recent available forecasts.

ECONOMICS

	2012	2013	2014	2015	2016
CPI – Ontario (%)	2.0	2.2	1.9	1.9	1.9

CPI-Ontario forecasts were based on the IHS Global Insight June 2012 forecast.

INTEREST RATES

	2012	2013	2014	2015	2016
HO1 5-Year Bond Rate (%)	2.18	2.43	3.98	4.58	4.88
HO1 10-Year Bond Rate (%)	2.90	3.15	4.70	5.30	5.60
HO1 30-Year Bond Rate (%)	3.82	4.07	5.62	6.22	6.52
90-Day Banker's Acceptance Rate (%)	1.19	1.77	2.76	3.74	4.56

H1 bond rates for 2012 and 2013 are prepared based on the August 2012 edition of Consensus Forecasts. 2014 – 2016 bond rates are based on the April 2012 Long term Consensus Forecast. Hydro One credit spreads are based on an average of indicative new issue spreads for August 2012 from the dealers in Hydro One's medium term note syndicate. The 90-Day Banker's Acceptance Rate forcast for 2012-2016 is prepared based upon the June 2012 Global Insight Forecast.

The impact of these updates on the revenue requirement for the test years are:

	2013	2014
Economics	$0.3M	$-0.2M
Interest Rates (Consensus Forecast)	$-1.3M	$0.7M
Change in Revenue Requirement	$-1.0M	$0.5M

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.

Ontario Energy Board (Board Staff) INTERROGATORY #8 List 1

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

Interrogatory

Ref: Exhibit A-13-1/Appendix A/p 4
Please provide another version of the table on Benefit Cost Rates and include 2009, 2010 and 2011.

Response

See updated version of the table with 2009, 2010 and 2011 data.

Company	Category	2009	2010	2011	2012	2013	2014	2015	2016
Networks	Non-Regular Staff % of total earnings*	6.23%	6.11%	5.75%	5.76%	5.80%	5.85%	5.85%	5.85%
	Regular Staff % of total earnings*	6.23%	6.11%	5.75%	5.76%	5.80%	5.85%	5.85%	5.85%
	% of base pensionable earnings**	25.55%	25.82%	28.25%	28.16%	28.18%	28.06%	27.66%	27.66%
	Pension % of base pensionable earnings	26.88%	26.01%	30.01%	29.51%	29.08%	28.78%	28.39%	28.39%

*CPP, Emp, Insurance, Emp. Health Tax, Workers' Compensation Schedule 1 Premiums
**Health, Dental, Life Insurance, Maternity, Retirement Bonus, Post-Retirement Health, dental, Life Insurance, Ontario Health Premiums (OHP), OPRB - Inergi
- Base Pensionable Earnings includes pensionable bonus.
- Total Earnings includes base pay, bonus, overtime, taxable benefits and taxable allowances.

Ontario Energy Board (Board Staff) INTERROGATORY #9 List 1

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

Interrogatory

Ref: Exhibit A/Tab 16/Sch 1/p 4
Hydro One indicates that it has adopted the Medical Attentions measure in favour of the Lost Time Injury metric. However, the Lost Time Injury metric is still shown at Figure 1. Please provide the Medical Attentions measure in a similar graph. With regard to the current Figure 1, what is responsible for the increase from 2010 to 2011? How is the duration of the injury reflected in this measurement?

Response

Medical Attention results for 2010 and 2011 are shown below (prior to 2010, data was not being analyzed using the same criteria so 2007 to 2009 data is not shown):

Table 1

# of Medical Attentions (MA) per 200.000 hours worked		
Year	**2010**	**2011**
MA Rate	2.6	3.7

The Canadian Electricity Association (CEA) does not use Medical Attentions Frequency as a measure and hence numbers are not available from the CEA to compare against.

Hydro One has analysed the medical attention injuries and there are no clear systemic work-related reasons for the increase. Hydro One's focus is on the reduction of medical attention injuries. It is not unusual for there to be variability in performance as you move ahead with continuous improvement initiatives in specific areas. Programs are focusing on prevention of motor vehicle accidents, musculoskeletal injuries (exertions), electrical contacts, etc.

"Duration" of injury is not reflected in frequency numbers (i.e., number per 200,000 hours worked).

Ontario Energy Board (Board Staff) INTERROGATORY #10 List 1

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

Interrogatory

Ref: Exhibit A/Tab 16/Sch1/p5
Hydro One indicates that the change in the Recordable Injury Frequency from 2010 to 2011 as shown in Figure 2 has increased but that the causes are still being researched by safety experts. Can Hydro One provide any update on the causes of this increase injury frequency at this time?

Response

Hydro One has analysed the medical attention injuries and there are no clear systemic work-related reasons for the increase.

Hydro One's programs center on prevention of motor vehicle accidents, musculoskeletal injuries (exertions), electrical contacts, etc. Hydro One's focus is also on the reduction of medical attention injuries, which are a component of recordable injury frequency and it is not unusual for there to be variability in performance as continuous improvement initiatives in specific areas move ahead.

Ontario Energy Board (Board Staff) INTERROGATORY #11 List 1

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

Interrogatory

Ref: Exhibit A/Tab 16/Sch 1/pp 12 - 18
Figures 1 through 10 appear to show that Hydro One's delivery performance to be consistently below the CEA Composite levels from 2003 to 2010, with an anomaly (forest fire) in 2011 that causes a sudden increase. In light of these results, how does Hydro reconcile its plans *to* significantly increase spending in replacing/refurbishing assets in the test years?

Response

Figures 4, 5 and 6 in Exhibit A, Tab 16, Schedule 1, pages 12 through 14 reflect delivery performance of the transmission system relative to the CEA Composite levels. These figures indicate that during the 2003-2010 period, the frequency of delivery point interruptions on Hydro One’s transmission system was better than the CEA Composite levels for most, but not all years. These figures also indicate improving frequency trends of both Hydro One and CEA Composite levels. Duration of interruption levels illustrated in Figure 6 indicate fairly constant levels of performance for that of Hydro One and CEA Composite levels.

Figures 7 and 8 in Exhibit A, Tab 16, Schedule 1, pages 15 and 16 reflect equipment unavailability due to forced outage performance. These charts indicate a deteriorating trend of unavailability for both transmission line and transmission station equipment. As stated on page 14 lines 15-16 of this evidence, the unavailability measure is considered to be a leading indicator of system performance.

As per Exhibit D1, Tab 3, Schedule 2 page 1, spending requirements are driven by the asset needs at the time, taking into account the number of assets determined to be in need of refurbishment or at EOL based on age demographics, condition data, reliability and performance information and cost.

The equipment performance trends indicated in Figures 7 and 8 of Exhibit A, Tab 16, Schedule 1 reinforce the necessity for increased investment to maintain acceptable levels of risk. Proactively addressing asset needs in a timely manner reduces the likelihood of coincident events occurring and impacting reliability to customers.

Ontario Energy Board (Board Staff) INTERROGATORY #12 List 1

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

Interrogatory

Ref: Exhibit A/Tab 17/Sch1/Figure 2
Please provide the compensation amounts that are used for the Compensation line of the graph shown at Figure 2.

Response

The amounts used for the Compensation line of the graph shown at Figure 2 are as follows:

2009: $28.6m
2010: $20.1m
2011: $15.9m
2012: $13.4m
2013: $12.2m
2014: $11.8m

Ontario Energy Board (Board Staff) INTERROGATORY #13 List 1

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

Interrogatory

Ref: Exhibit A/Tab 17/Sch 2/Table 4
Please provide the results from 2009 to 2011 and a preliminary figure for 2012 as shown in Table 4.

Response

The actual results from 2009 to 2011 for the Table 4 calculation are as follows:

2009: 11.8%
2010: 11.2%
2011: 9.8%

The current year-end estimate for 2012 is 10.1%.

Ontario Energy Board (Board Staff) INTERROGATORY #14 List 1

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

Interrogatory

Ref: Exhibit A/Tab 17 /Sch2/p 3
Hydro One indicates that it chose three activity metrics from the suggested Oliver Wyman metrics, based on materiality and business impact Please provide additional detail on the materiality/business impacts of the three metrics and why others were not selected.

Response

The three metrics were selected based on materiality and business impact. Together these three programs represent 7% of the total maintenance plus capital Sustainment work program spend, which represents 9% of the maintenance spend and 5% of the capital spend in the test years. They are large, well established programs with good data at the activity level, stable allocations of funding year over year and therefore consistently executed and tracked across the field organizations. These are important programs to the business as they directly impact achieving Hydro One's Strategic Objectives of Transmission Reliability, Shareholder Value, Productivity, and Safety.

Other metrics were not selected as there are still some field data collection issues in some programs, an example being data may not be collected at the activity level, making year over year comparisons difficult and therefore making them not ready yet to be used as productivity metrics. Other programs were not selected as their materiality was relatively low or the business impact is lower than the three that were selected and the cost to collect the data would be significant.

Ontario Energy Board (Board Staff) INTERROGATORY #15 List 1

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

Interrogatory

Ref: Exhibit E 1/Tab 1 /Sch 1 /pp 3&5
The tables on these pages show the proposed 2014 total revenue requirement is 6.4% above the proposed 2013 requirement, and 9.9% above the approved 2012 requirement While a brief explanation is provided below each table, please provide additional detail on the main reasons for the 2014 increase relative to previous years.

Response

The main reason for the 2014 increase relative to previous years is due to the growth in rate base. Rate base is projected to grow an average of 8.5% annually over the next 3 years.

The OM&A component of revenue requirement has increased due to increasing maintenance requirements of an aging and expanding transmission system.

The depreciation component of revenue requirement has increased due to growth in rate base partially offset in 2013 by the impacts of the depreciation study by Foster Associates as filed in Exhibit C1, Tab 8, Schedule 1, Attachment 1.

The cost of capital component of revenue requirement has increased due to growth in rate base partially in 2013 offset by the impact of a lower consensus forecast on return on debt and return on equity rates.

London Property Management Association (LPMA) INTERROGATORY #1 List 1

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

Interrogatory

Ref: Exhibit A, Tab 15, Schedule 1

Please update Tables 1, 2, 3 and 6 to reflect the most recent forecasts available.

Response

Updated table 1 – Please refer to Interrogatory Response filed at Exhibit I, Tab 3, Schedule 1.01 Staff 16.

Updated table 2 – Please refer to Interrogatory Response filed at Exhibit I, Tab 2, Schedule 1.05 Staff 6.

Updated table 3 below

	Historic			**Bridge**	**Test**	
	2009	**2010**	**2011**	**2012**	**2013**	**2014**
Exchange Rate (CDN$ per US$)	1.142	1.030	0.989	1.007	0.995	1.023

Update table 6 – Please refer to Interrogatory Response filed at Exhibit I, Tab 3, Schedule 1.02 Staff 17.

Energy Probe (EP) INTERROGATORY #1 List 1

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

Interrogatory

Ref: Exhibit A, Tab13, Schedule1, Appendix A, Pages 1-4

a) Please provide a copy of each of the November 2011 and April 2012 Updated Business Plans approved by the Hydro One Board.

b) Please provide a copy of the Business Plan instructions post the Board's December 2011 Decision.

c) Please provide a variance report for 2011 actual and forecast 2012-14 Economics, Interest rates, Labour rates and Payroll Burden that shows the major changes from the Approved Business Plan underpinning Hydro One Networks' 2011/12 Transmission Rate Application.

d) In particular, please provide the details underlying the interest rate forecast (Bond rates).

e) Is Hydro One Networks aware of any more recent projections of inflation and cost escalation for 2011 and 2012? If yes, please provide these.

f) Please provide an update of the interest rate forecast for 2012 -2016 based on the latest edition of Consensus Forecasts.

g) What is the sensitivity of Hydro One Networks' proposed 2013 and 2014 revenue requirements to:
- A 100 basis point change in forecast interest rates. (Note: Please exclude any impact on ROE or short-term interest rates used in determining the cost of capital)
- A 1-cent change in the forecast exchange rate (CDN$ per US$)?

Response

a) Hydro One has filed the attached Interrogatory request pursuant to the Board's Practice Direction on Confidential Filing. Hydro One's Disclosure Policy, as well as applicable securities legislation, prohibits the release of non-public, financial information on a selective basis to individuals or groups of individuals. In addition the Business Plan includes information with respect to matters that are outside the scope of this proceeding. Hydro One is prepared to share a copy of the confidential filing with intervenors who sign the Board's confidential undertaking form. Please see Attachment 1 and 2 for redacted versions of the requested information.

b) The Business Plan instructions post the December 2011 Decision of the Board has been filed pursuant to the Board's Practice Direction on Confidential Filing. Hydro One's Disclosure Policy, as well as applicable securities legislation, prohibits the release of non-public, financial information on a selective basis to individuals or groups of individuals. In addition the Business Plan instructions include information with respect to matters that are outside the scope of this proceeding. Hydro One is prepared to share a copy of the confidential filing with intervenors who sign the Board's confidential undertaking form. This plan is currently under development and neither the plan nor the assumptions therein have been presented to Hydro One's Board of Directors for Approval.

c)

	Variance			
	2011	2012	2013	2014
Economics				
CPI - Ontario (%)	1.0%	-0.1%	0.0%	0.0%
TX cost escalation for Construction (%)	1.2%	0.3%	-0.3%	0.3%
TX cost escalation for Operations & Maintenance (%)	0.6%	-0.2%	0.1%	0.1%
DX cost escalation for Construction (%)	0.9%	0.0%	-0.2%	0.4%
DX cost escalation for Operations & Maintenance (%)	1.5%	0.3%	0.1%	0.1%
Interest Rates				
HO1 5-Year Bond Rate (%)	0.0%	0.3%	0.3%	0.7%
HO1 10-Year Bond Rate (%)	0.0%	0.1%	0.1%	0.6%
HO1 30-Year Bond Rate (%)	0.0%	0.1%	0.1%	0.6%
90-Day Banker's Acceptance Rate (%)	0.0%	-0.1%	0.1%	0.0%
Interest Capitalized TX (%)	0.0%	-0.1%	0.0%	0.0%
Labour Rates				
MCP	-3.0%	-2.0%	-2.0%	-2.0%
Society	0.0%	0.0%	-1.5%	-2.0%
PWU	0.0%	0.0%	-1.5%	-2.0%
STI	n/a*	0.0%	0.0%	0.0%
* note $9.4M was paid in STI for 2011				

d) Refer to Exhibit I, Tab18, Schedule 9.02 SEC 37.

e) Refer to Exhibit I, Tab 2, Schedule 1.05 Staff 6.

f) Refer to Exhibit I, Tab 2, Schedule 1.05 Staff 6.

g) A 100 basis point decrease in forecasted interest rates would decrease revenue requirement by $5.16M in 2013 and $12.96M in 2014.

As per line 16, page 3 of Exhibit A, Tab 15, Schedule 1, the exchange rate forecast is not directly used to forecast costs or other variables, therefore the calculation of 2013 and 2014 revenue requirement would not be impacted.

Date: November 10, 2011

Subject: Hydro One Inc. 2012 Budget & 2013/2014 Outlook

Submitted by:

Sandy Struthers
Executive Vice President and
Chief Financial Officer

Approved for Submission to the Board by:

Laura Formusa
President and Chief Executive Officer

RECOMMENDATION

THAT the Board of Directors of Hydro One Inc. ("Hydro One" or "the Company") approve the 2012 Budget and 2012 to 2014 Outlook ("Budget") set out in Schedule A.

KEY HIGHLIGHTS

- The Budget maintains Hydro One's focus on striking a balance amongst the expenditures associated with the implementation of the Long Term Energy Plan ("LTEP"), the costs and challenges of connecting distributed generation ("DG"), the execution of our sustainment programs and the realities of rate impacts on our customers.

- The Budget is prepared based on information available at the date of this memorandum and assumes no substantial change in the nature of the Company's role in the Ontario electricity industry, corporate mandate, or structure, and is consistent with the Strategic Plan. Our success in achieving the Strategic Plan is measured by how well we can provide safe, cost-effective and reliable electricity delivery to our customers.

- The Budget's focus is on addressing aging infrastructure, needed asset replacement and ongoing maintenance programs without which current and future system reliability will be negatively impacted. Achieving these objectives requires a realignment of work processes to decrease administrative costs and improve productivity. Hydro One Networks' OM&A costs increase by less than inflation on average over the Budget period.

- The Budget assumes a moderate growth in work program, but no increase in regular staff over the period. It includes several productivity initiatives and a resourcing strategy aligned with our focus on mitigating rate impact to our customers.

- To address customers' concerns regarding bill impacts, increases in work programs over the Budget period have been limited, resulting in an average impact on total bill of less than 1.5% for both transmission and distribution customers. Rate increases are primarily driven by new infrastructure projects (Bruce x Milton) being included in rate base during the Budget period and reflect moderate growth in OM&A and capital spending.

- Funding for the new Customer Information System ("CIS") is included in the Budget period and its implementation in 2012/13 will improve customer service and corporate productivity.

- Focus is maintained on reducing support expenditures for the Company by limiting salary and wage increases to reflect government guidelines. The results of these efforts are highlighted in an updated Mercer survey, which shows our wages for management have dropped below market. Non-labour support costs have been successfully reduced with the renegotiation of the Inergi contract, and further decreases are planned in purchasing and outsourced services.

- The Budget assumes that the Company will operate as a commercial business enterprise and as such will earn the allowed regulated rate of return. Assuming Ontario Energy Board ("OEB") approval, [redacted]

- The Budget also includes three of five priority transmission projects that were included in (a) the Government's LTEP of November 23, 2010, and (b) the OEB's amended conditions for Hydro One's transmission licence that were codified on February 28, 2011. These projects comprise:
  - Devices to enhance the transfer capability in Southwestern Ontario
  - Re-conductor circuits West of London
  - New transmission line West of London

- The Budget does NOT include funding for:
  - A new East-West tie ("EWT") line. This project will be developed by a transmitter selected by the OEB through a designation process. The Budget provides for $12 million in funding, in Hydro One Inc. ("HOI"), for the designation portion of the EWT project line. Any funding requirements sought for the project implementation will be brought forward to the Hydro One Board for approval as required.
  - A line to Pickle Lake, Ontario. This project will be undertaken as a load connection expansion.
  - LDC acquisitions or disposition of any portion of the Hydro One service territory or operations.

- Upgrades at up to 15 Transformer Stations to enable the connection of small-scale renewable generation are planned as non-recoverable expenses. The costs of these projects are assumed to be borne by the Shareholder and are offset by efficiencies obtained outside of the regulated work program.

- To enable work program delivery, approval to release work program funding envelopes for 2012-14 is requested, consistent with the Organizational Authority Register ("OAR"). Projects will continue to be released upon business case approval consistent with the OAR. Implicit in the work program approval is the approval to purchase long-lead materials that support work and work programs. With the aging of assets reaching elevated levels, work program flexibility to reprioritize programs and projects, as required, will be maintained.

- The Company sought and received an exemption from the Ontario Securities Commission allowing it to file its Consolidated Financial Statements and MD&A in US GAAP for the period January 1, 2012 to December 31, 2014. Hydro One Networks has subsequently applied to the

OEB to have rates set on the basis of US GAAP rather than modified IFRS for its Transmission business. A decision is expected by the end of November. The requests for the OEB to approve the use of US GAAP for the Distribution business and Hydro One Remotes are outstanding.

The Budget presentation is attached as Schedule B and work program details are attached as Schedule C.

This Board Memorandum was reviewed and approved for submission to the Board of Directors of Hydro One Inc. by the Audit and Finance Committee at its meeting on November 9, 2011.

EXECUTIVE SUMMARY

1. Strategy

The Budget establishes the level of operations, maintenance and administration ("OM&A") and capital expenditures over the planning period, as well as net income and critical financial metrics. The Budget reflects the Company's mandate, vision, values, and drives towards meeting the strategic objectives. The Budget also considers the Corporate Risk Profile. A long-term investment plan has been developed for transmission and distribution that includes the investments required to support distributed generation ("DG"). End-of-life ("EOL") assets are driving the need for a ramp-up in investments over the longer term. This trend has been tempered with program and cost reductions to address customer rate concerns in the shorter term. With these reductions, the Company anticipates maintaining Q1 reliability performance for its transmission assets but customers may experience some slippage within the Q3 performance of the Company's distribution assets. We will monitor the impact of these program and cost reductions on the reliability and safety of the aging electricity grid. If required, it may be necessary to reallocate funding to address emerging risks.

2. Purpose

The purpose of the Budget submission is to ensure that the mandate of the Company regarding the safe, reliable and cost-effective transmission and distribution of electricity to Ontario's electricity users is achieved. The submission supports the governance, financial, and performance requirements of the Shareholder, while recognizing the needs of our customers.

The Corporate Business Plan is developed from Management's and the Hydro One Board of Directors' agreed Corporate Strategy and from the Hydro One Board of Directors' and Management's review of the risks that the Company faces. The Business Plan, as reflected in the Budget, attempts to mitigate the identified risks and to deliver a work program and financial performance that supports the Company in delivering the Corporate Strategy while at the same time recognizing rate impacts on customers. The Corporate Scorecard measures the Company's progress in achieving the Business Plan and the Budget metrics as it progresses forward in achieving the Corporate Strategy.

The Budget sets out the financial requirements for 2012 and requests approval to release work programs for the years 2012-14 through a structured process. Programs represent known recurring work and the structured multi-year release process is necessary to maximize critical skill sets, increase productivity and enable long lead-time materials to be acquired on a timely and cost effective basis. Work program flexibility to reprioritize work programs and projects, as required, will be maintained. Projects are released on the basis of individual business cases, as there may be several alternatives available with respect to scope and design. Implicit in the work program approval is the approval to purchase long-lead materials that support project work and work programs. Once approved, authority will be delegated to implement these requirements in accordance with the Organizational Authority Register.

3. Cost Estimate and Recovery

Key financial results in U.S. generally accepted accounting principles ("US GAAP") are as follows:

$M except where noted	**2011**(1)	[redacted]
Revenue	5,467	
Income before PILs	771	
Net Income	613	
EBITDA	1,723	
Cash Flow	(427)	
Debt Ratio	56%	
FFO Coverage	3.9x	
Total Rate Base	13,161	
ROE (GAAP)	10.1%	
Capital Expenditures	1,510	
OM&A	1,106	
Dividends	168	
PILs	157	
Total Long-Term Debt	8,132	
Total Equity	6,427	

(1) Projected

The Budget reflects growth in net income from 2012 to 2014. This growth reflects increases in transmission and distribution revenue requirements, consistent with work program requirements. Rate base growth, reflecting the in-servicing of ongoing capital work programs, is the primary cause for the increased revenue requirement and net income. The Shareholder reflects the Company's net income and PILs in the Province's books and records. Over the 2012 to 2014 period, these amount to $2,333 million. Common dividends have been managed to maintain capital structure and enterprise value.

The Budget continues to include significant funding requirements reflecting Government policy decisions and investments to maintain system reliability and safety. Highlights include:

- Transmission expenditures including component replacements, such as circuit breakers and metalclad switchgear, high voltage underground cable replacement, EOL transformer replacement, and other major EOL equipment replacements.
- Transmission sustainment investments at several critical stations (e.g. Manby, Leaside, Cherrywood, Burlington) to ensure operating reliability and development expenditures in Smart Grid to upgrade protections to enable DG. The Budget assumes that approvals required for planned work will be received by the distributed generators. In 2011, many of the approvals required to proceed with DG work and system expansion were delayed.
- Transmission development expenditures, including completion of Bruce x Milton, Commerce Way TS, Hearn TS, Leaside x Bridgeman 115kV circuit, SW Ontario Series Compensation Milton TS SVC, and a new 500/230kv station at the Oshawa Area TS, for which we recently received a communication from the Ontario Power Authority to begin planning for possible in-service date of 2015.
- Distribution sustainment work programs continue to reflect reduced expenditures consistent with the Ontario Energy Board's ("OEB") decision on our 2010/11 distribution application. The plan-over-plan reductions in vegetation management and line maintenance programs are

partially offset by additional investments in Customer Care to support DG and smart metering activity.

- Distribution development expenditures primarily related to customer demand work, DG connections, and investments related to the rollout of Smart Grid as the development of the technical solution (Distribution Management System and intelligent field devices for monitoring and control) continues and will start to be implemented in areas of the Province where operational need is the greatest.
- Funding to address Environment Canada's final regulations governing the management, storage, and disposal of polychlorinated biphenyls ("PCBs").
- Funding for Phase 4 of the Cornerstone Project which will replace the Company's Customer Information System ("CIS") and further the productivity realization of the entity-wide platform. The project commenced in 2011 and remains on schedule for go-live in October 2012, with inclusion in rate base in 2013.
- Funding to comply with NERC cyber security requirements.

The Long-term Energy Plan ("LTEP") was released by the Government on November 23, 2010. The plan identified five priority transmission projects and Hydro One was instructed to undertake three of the projects. On February 17, 2011, the Government directed the OEB to include these three projects as part of our licence condition. The government also included an additional project, outside of the LTEP, to upgrade up to 15 transmission stations to accommodate small scale renewable generation (e.g. MicroFIT). The OEB updated Hydro One's transmission licence with these four conditions on February 28, 2011. As a result of delays related to environmental approvals and other items, the levels of investment in DG connections have been reduced to include only those projects where there is a clear line of sight to connection.

The LTEP also identified a new East-West tie ("EWT") line as a priority project to maintain long-term system reliability in Northwest Ontario. On March 29, 2011 the government expressed an interest that the OEB undertakes a designation process to select the most qualified and cost-effective licensed transmission company to develop the EWT project. Hydro One has entered into a partnership with Brookfield and affected First Nations to participate in the designation process. The plan provides $12 million in funding, in HOI, to participate in the OEB's designation process for the EWT project. Any funding requirements sought for the project will be brought forward to the Hydro One Board for approval as required.

The plan does not include funding for LDC acquisitions or assume any disposition of the Company's service territory. These opportunities will be managed as they arise.

4. Regulatory

The electricity industry in Ontario has undergone significant change during the past several years which has impacted customers' bills. The OEB has recognized customer concerns about rising costs and consequently, Hydro One will continue to face increased regulatory scrutiny of any request for rate increases.

An OEB decision on our request to adopt US GAAP for our Transmission business effective January 1, 2012 is expected by the end of November. Hydro One will file a request to have distribution rates declared interim on January 1, 2012. As part of the interim rate request, Hydro One will seek approval to adopt US GAAP for the Distribution business. A request will also be made to have Hydro One Remote Communities file for use of US GAAP in its rate applications.

In April of 2012, in order to support Business Plan and Budget requirements, Hydro One intends to file a combined transmission and distribution multi-year rate application that would cover transmission and distribution rate requirements for 2013 and 2014 and distribution rate requirements for 2012.

If approved, transmission rates would increase by approximately 7.0% in 2013 and 10.2% in 2014, (an average of 0.65% increase on the total bill, each year). These increases support aging infrastructure and government supply mix initiatives.

The proposed distribution cost-of-service rate applications for 2013 and 2014 would decrease rates by approximately 2.7% in 2013 and increase rates by 7.2% in 2014 (an average of 0.75% increase on the total bill, each year). No increase is proposed for 2012 with existing rate riders and variance accounts remaining in place until 2013. The increase in 2014 follows an effective rate freeze in 2012 and 2013. Rate increases in 2014 and beyond are driven primarily by additions to rate base and moderate increases to work programs.

In the event the OEB imposes an Incentive Rate Mechanism ("IRM") on Hydro One's Distribution business, or significantly reduces the work program for either the Distribution or Transmission business, system reliability will decline.

5. Risk Summary

There are a number of risks which could impact the accomplishment of this Budget. Although most of the risks are consistent with prior business plans, the level of certain risks has increased. First Nations and Métis Relationship uncertainty remains a very high risk. We anticipate the likelihood of this risk to increase and to impact our ability to complete work programs and projects. The United Nations Declaration on the Rights of Indigenous Peoples and the concept of "free prior and informed consent" are increasingly used by First Nations and Métis as leverage for consultation, which the Company is required to undertake. There is a very real risk that both future work and work in progress could be delayed until First Nations and Métis expectations are met.

Additionally, four new risks have been identified since the last Budget: Labour Relations Uncertainty, Outsourcing Risks, Cost Reduction/Productivity and Human Resources Risk. These risks are, to some extent, interrelated. It is anticipated that there will be continued pressure from the Shareholder and the OEB to reduce labour and work program costs. Reduced labour costs and/or productivity improvements are critical to support a growing work program without an associated growth in regular staff. These pressures will converge as we approach expiry of both the PWU and Society collective agreements in 2013 and the issuing of an RFP in 2013 for the renewal of the outsourcing services agreement, which expires February 2015.

Other significant risks that Hydro One faces include: uncertainty of government policy; increased risk of equipment failure due to increased age; uncertainty regarding future investments prompted by the Green Energy Act; an increasingly complex regulatory environment; availability of staff resources to execute the work program; increasing reliance on information technology; cyber threats and virus attacks; and the possibility of new NERC compliance requirements which may be applicable to our transmission and distribution systems.

hydroOne

SCHEDULE A

HYDRO ONE INC.
2012 BUDGET & 2012 to 2014 OUTLOOK

1. INTRODUCTION

The 2012 Budget and 2013/2014 Outlook ("Budget") summarize the financial results reflecting Hydro One Inc.'s ("Hydro One" or "the Company") commitment to making necessary investments in core Transmission and Distribution infrastructure, consistent with the Strategic Plan. Hydro One's focus continues to be on the operating, productivity and economic performance of the core utility operations (comprising Hydro One Networks Inc.'s ("Networks") Transmission and Distribution businesses, Hydro One Brampton Networks Inc. ("Brampton") and Hydro One Remote Communities Inc. ("Remotes")) to provide safe, cost-effective and reliable electricity delivery services to our customers, and providing increasing enterprise value to our shareholder, the people of the province of Ontario. Productivity, value for money and improved employee and customer communications will be key areas of focus. The Budget includes investments required to connect and support Distributed Generation ("DG") and investments made consistent with the Long Term Energy Plan ("LTEP").

This Budget and the underlying business plan are based on a number of assumptions which are included in Section 3 "Key Planning Assumptions". If, subsequent to approval of the Budget, information arises or decisions are made that materially impact these assumptions, including from regulatory decisions, this Budget will be revised and resubmitted to the Hydro One Board of Directors for consideration and approval.

2. STRATEGY

The Budget is consistent with the Company's mandate, vision, values and strategic objectives. A scorecard is used to measure annual progress toward the strategic objectives. The 2012 Scorecard uses weighting to place specific emphasis on productivity, reliability, customer satisfaction, employee engagement and financial performance. While these elements reflect the outcome of the work program, the safety aspects of how the work program is delivered are also considered in the Scorecard. A one page summary of the Hydro One Strategic Plan is attached as Appendix A. The work plan was developed on the basis of balancing our strategy, while recognizing the uncertainty of the Green Energy Plan, the global economy, and the new realities and challenges our customers face.

i) Productivity and Cost-Effectiveness

Productivity improvements and cost-effectiveness, together with innovation, are the keys to delivering a work program that ratepayers can afford. Productivity cost reductions of approximately $280 million across the 2012 to 2014 period have been embedded in the plan. There are multiple initiatives underway to increase productivity and ensure the effectiveness of investments:

- **Deployed:** SAP tools are providing the information necessary to more effectively manage work, optimize investments in the assets and provide the necessary visibility to managers to control costs. The original SAP implementations are also providing effective platforms for seamless integration of new tools and applications, which support greater analytics and increase productivity. Cornerstone Phase 1, 2 and portions of Phase 3 that are complete are tracking to plan and are set to deliver approximately $135 million in benefits.
- **Deployed:** Outsourcing Cost Savings. Additional savings have been achieved through the Inergi renegotiations; including project spend rebates, reduced charges for minor enhancements, and rate card savings, totalling approximately $65 million.
- **Deployed:** Non-labour cost savings enabled by enhancements to telephone, video and web conferencing have reduced the cost and coordination required to effectively communicate across the organization while reducing travel expense and time. These total approximately $15 million.
- **In-Progress:** We continue to expand our SAP enabled transformation across the areas of Asset Analytics, Asset Investment Planning, Business Planning, Customer Information Systems, GIS and ongoing continuous improvement initiatives. These initiatives have a plan to achieve in the range of $50-60 million.
- **In-Progress:** Updates to the Wide Area Network to reduce leased line costs and increase bandwidth will result in savings of approximately $8-10 million.
- **Future:** Business Transformational Initiatives. During the Business Plan period we will implement new initiatives in the areas of engineering design, work planning, scheduling, dispatch and mobility to further drive productivity and reduce cost.

Effective use of human resources and ensuring correct skills will be critical to attaining the balance between meeting the asset needs and mitigating rate impact on the customer. Although the work program will grow by an average of 3% per year through 2016, regular headcount will be maintained at 2011 levels. As attrition occurs, there will be a managed process to increase the proportion of staff who work directly on a project or program, while decreasing those in an indirect or support role. We will continue to hire new staff through the apprenticeship programs based on the required staffing ratios.

Union contractual limitations to operational flexibility will be identified with a view to negotiating alternatives that meet the needs of both Hydro One and the Unions. Our focus must continue to be the timely effective training of new resources, documented procedures and job aids to maximize knowledge transfer. Managing costs associated with benefits, and rising labour costs will also be a priority.

Emphasis will be placed on management to be more effective in their use of staff. Management will be held accountable in ensuring required work programs are delivered efficiently and effectively. Management effectiveness programs and measures, currently being piloted through the Craft of Management program, have been well-received and will be further deployed across the Company to aid in achieving these objectives.

ii) Reliable Transmission and Distribution

To ensure the electricity system's reliability in the public interest, we are planning significant investments in the transmission and distribution infrastructure. The Budget includes investments to maintain, refurbish and replace existing assets that have reached their end-of-life ("EOL"). These investments will continue to focus on specific mission critical equipment and stations that support generation facilities and the unrestricted supply of energy to customers throughout the Province, as well as responding to customer supply issues.

The success of the SAP system replacement has created an opportunity to access and manage large amounts of data enabling the asset managers to perform comprehensive reviews of asset performance. The preliminary results of major asset categories indicate that Hydro One's assets are in the midst of a profound demographic change: the rapid aging of its infrastructure as reflected by an increasing proportion of assets reaching EOL and an increasing average asset age. The table below identifies the EOL statistics for our major asset categories.

EOL Demographics by Asset Portfolio

Asset Portfolio	**Current EOL** % of Fleet Currently at Demographic EOL	**10yr EOL*** % of Fleet at Demographic EOL in 10yrs
Tx Protections	32%	54%
Dx Stations Transformers	32%	50%
Tx Circuit Breakers	30%	51%
Tx Power Transformers	27%	49%
Tx Wood Poles	27%	33%
Tx Underground Cables	19%	36%
Tx Overhead Lines	16%	32%
Tx Steel Structures	14%	25%
Dx Wood Poles	5% + 3% [redacted] (degrading prematurely)	29% + 3% [redacted]

* Assumes assets are not upgraded, refurbished or replaced over 10-year period.

Ongoing analysis of asset requirements using the SAP tools will continue to be conducted and evaluated to ensure safety and reliability of the system is optimized within financial and resource constraints.

iii) Satisfying Our Customers

Various initiatives will be undertaken during the planning period to maintain or move toward the target of 90% overall customer satisfaction. Customer satisfaction is currently tracking lower than target. Results are being pressured due to industry rate increases required to implement Government Policy initiatives and to fund necessary investments. Hydro One's customers have experienced an unprecedented period of change (e.g. smart meters, time-of-use ("TOU") billing) and a six-year period of rising rates to support much needed electricity infrastructure reinvestment. This activity against a backdrop of a poor economy and high levels of unemployment continues to erode customer satisfaction.

At the heart of customer discontent is the lack of awareness and understanding of electricity and Ontario's electricity sector and the value customers receive in return for their rates. We are focused on proactive customer interactions at all levels, such as calls to customers to triage abnormally large TOU bills prior to issuance and through the use of a special team of agents to handle distributed generator inquiries and requirements. In addition, the implementation of our new Customer Information System ("CIS") will allow us to address current needs and realize immediate value by replacing a costly stand-alone system with a more flexible platform. The capability enhancements of CIS will allow us to improve on key metrics directly linked to our 90% Customer Satisfaction goal as it will provide analytic and segmenting capability to establish customer profiles and ensure customer communications are targeted, meaningful and timely.

As part of our strategic plan, innovation is a key enabler to address aging infrastructure needs with technological advances in the utility sector. Hydro One strives to balance being an industry leader in developing innovations that better serve our customers with the economic reality of increasing rate pressures. Hydro One is a world leader in Smart Metering and the implementation is essentially complete with 1.05 million customers converted to TOU as of June 30, 2011, all of which is unprecedented in North America. The current plan provides for further conversion of customers to TOU using the smart meter communications networks and technical variations to increase network reach where it is commercially justifiable to do so. It also includes an allowance to develop a tool to manually extract the interval data for the smaller number of customers where the development of the communication network is uneconomic.

Smart Grid leverages the Smart Meter data and the communications network already deployed to address the integration of DG in our distribution network. The technical solution for Smart Grid continues to be developed and a Distribution Management System ("DMS") combined with intelligent field devices will start to be implemented in areas of the Province where the operational and customer need is greatest. Smart Grid not only supports DG, but can be leveraged in many ways to increase productivity such as automated crew dispatch and effective outage management, also benefiting our customers. Through the use of Smart Grid technology we will be able to better manage the amount of system rebuild required to support embedded renewable generation.

iv) Employee Engagement

Employee engagement is a critical success factor given the challenges of leadership succession and retention, labour demographics and development of critical staff. An engaged staff has been identified as a key element in driving work efficiency and effectiveness and high levels of customer satisfaction. The Q12 survey will continue to be utilized as both a gauge of current employee sentiment, and a platform from which to implement improvements.

As the Craft of Management Program continues to be rolled out, the resulting clarity in accountability is improving decision-making. It is also highlighting areas where the organizational structure is not enabling effective work practices. Organizational changes are being made as a result.

v) Shareholder Value

Consistent with the Memorandum of Agreement with our Shareholder, the Province of Ontario and as a reporting issuer under the Ontario Securities Act, we are required to operate on a financially sustainable basis and to maintain or increase the value of assets for our Shareholder. The Budget delivers financial returns consistent with the return on equity ("Regulated ROE") permitted by the OEB while balancing, where possible, customer rate impacts and the requirements associated with aging infrastructure and government policy requirements. The Company continues to maintain strong credit ratings and has the ability to access capital at cost effective rates. The Budget continues to support those objectives and maintains acceptable levels of debt, financial metrics, return on equity and growth in corporate value as construction work in progress is converted into an increasing rate base over the Budget period.

vi) Injury-Free

Given the nature of our work, safety remains the Company's top priority. We continue to focus on creating an injury-free workplace and maintaining public safety through several health and safety initiatives, including Journey to Zero. We continue to build on programs like Employee Health and Wellness for mental health issues, and Ergonomic assessments for musculoskeletal disorders to positively impact our employees' well-being. The Company has passed the WorkWell audit and is targeting OHSAS 18001 registration in 2013.

3. KEY PLANNING ASSUMPTIONS

The Budget is based upon a number of key assumptions. Given the level of uncertainty in the industry, new information, such as rate decisions and policy direction, could materially impact the validity of the underlying assumptions and ultimately the achievement of the Budget. The key planning assumptions are outlined below.

i) Regulatory

The financial results being put forward are predicated on obtaining timely OEB approval for rate increases for the 2013 and 2014 test years consistent with infrastructure requirements. No increase is proposed for 2012 with existing rate riders and variance accounts remaining in place until 2013. The Regulated ROE for 2012 is 9.42% down from 9.66% in 2011. In 2013 and 2014, the Regulated ROE is projected to be 9.7% and 10.2%, respectively.

ii) Government Policy and Green Energy

Hydro One's expenditures in the Budget for DG Green Energy initiatives are based on the experience gained since 2009 and the changes to the Feed-in-Tariff (FIT) program that have occurred. For the larger Non-Capacity Allocation Exempt (CAE) projects, only expenditures for projects with FIT contracts and signed connection agreements that are expected to connect to Hydro One's distribution system are included in the Budget. The Budget also includes expenditures for CAE and MicroFIT projects that are expected to connect. Incorporation of distributed generators on the distribution network is being assisted by the results of Hydro One's Smart Grid Advanced Distribution System ("ADS") initiative. The integration of a DMS, combined with intelligent field devices, will provide the platform to address challenges posed by distributed generators. For 2012 through to 2014, Hydro One is requesting the continuation of the variance accounts approved by the Board in the previous proceeding along with the rate riders.

The Ministry of Energy released Ontario's LTEP on November 23, 2010. The LTEP identifies five priority transmission projects as follows:

- Devices to enhance the transfer capability, such as series or static var compensation or similar devices, in Southwestern Ontario; – in-service 2015
- Re-conductor circuits West of London; – in-service 2014
- New Line West of London; – in-service 2017
- East-West Tie ("EWT") line; – in-service 2016-17
- New Line to Supply Pickle Lake; – in-service pending consultation

On December 22, 2010, the Minister of Energy provided an update to the September 21, 2009 letter. The update does not specify the disposition of all the projects that the then Minister of Energy and Infrastructure asked Hydro One to immediately plan, develop and implement in anticipation of the Feed-in-Tariff program. The letter requests Hydro One to immediately proceed with the necessary planning and development work to advance the first three of the priority projects; devices to enhance transfer capability in Southwest Ontario such as series or static var compensation; re-conductoring of Sarnia to London Circuits and; a new transmission line west of London.

On February 17, 2011, the Minister of Energy directed the OEB to amend the licence conditions of Hydro One to include a requirement that Hydro One proceed with the first three priority projects stated in the letter of December of 22, 2010 and also included the requirement to increase the short circuit and/or transformer capacity at up to 15 of Hydro One's transmission stations. These licence amendments were executed by the OEB on February 28, 2011.

The Supply Mix Directive was issued to the Ontario Power Authority ("OPA") on February 17, 2011 by the Minister of Energy. The Supply Mix Directive outlines the Government's goals to be achieved through long term Integrated Power System Plan to be developed by the OPA and submitted to the OEB for approval.

Hydro One has included funding for the development and implementation of the three priority transmission projects in the Budget. On June 30, 2011 Hydro One started work on the re-conductoring of the West of London circuits based upon the OPA's recommendation. On October 3, 2011, work began on installing a static var compensation device at the Milton Switching Station based on the recommendation of the OPA. Work on the New Line West of London will commence once an appropriate letter is received from the OPA. The current plan assumes that preliminary work will commence in 2013.

The OEB released a new policy paper on August 26, 2010, *Framework for Transmission Project Development Plans*, which provides for competitive bidding for various types of new build projects. This process also allows the OEB to designate projects to the incumbent transmitter in certain situations.

On March 29, 2011, the Minister of Energy sent a letter to the OEB to "express the Government's interest that the OEB undertake the designation process to select the most qualified and cost effective transmission company to develop the EWT." In response to the OEB's request to the OPA, the OPA has submitted a report to the OEB regarding the preliminary assessment of the need for the EWT line. On August 22, 2011, the OEB invited licensed transmitters to register their interest in filing a plan to develop the EWT project by September 21, 2011. As a result, seven licensed transmitters registered including EWT LP of which Hydro One is a partner. Hydro One Networks did not register. The Budget does not provide funding for the EWT project.

As per the OEB's approval, we are continuing to account for allowance for funds used during construction on the Niagara Reinforcement Project and monitoring for changes in the status of the project.

iii) Load

The transmission load is forecast to decline by 1.1% in 2012, 2.5% in 2013 and 0.6% in 2014 primarily due to the effects of CDM. The transmission load forecast reflects the current OPA CDM forecast. Similarly, the distribution load is forecast to decline by 0.5% in 2012 and 0.3% in 2013. The distribution load is forecast to increase by 0.4% in 2014.

iv) Employees

Staff Headcount	2012	2013	2014
2012-14 Budget	5,913	5,913	5,916
2011-13 Budget	6,182	6,217	6,306
Variance	(269)	(304)	(390)

Although the Budget assumes a moderate growth in work program, there is no increase in regular staff over the period. On a plan-over-plan basis, staff levels have been reduced significantly due to a lower work program and the limitations placed on support staff. Salary and wage levels reflect government guidelines. Management salaries were frozen in 2010 with the exception of first level managers to address compression with union staff.

The Company has reviewed the employee benefit cost forecasts and the assumptions relating to health care trend rates, demographics, and claims data have been updated. Although Hydro One has not granted new benefits to employees, benefit costs (excluding pension costs) have increased in aggregate compared to last year (2012 Budget of $188 million versus $173 million in the 2011 Budget). The increase is primarily due to the lower discount rate at the end of 2010.

Annual pension contributions are established as a result of a pension valuation which is completed tri-annually. A new pension valuation was received in 2010, resulting in increased annual pension contributions (2012 Budget of $149 million versus $143 million for 2011). No new pension entitlements have been granted. The next valuation for the Hydro One defined benefit plan is December 31, 2012 with a new annual contribution amount payable in 2013. It is anticipated that if long-term interest rates remain low and stock markets do not perform that this amount will increase significantly from the existing levels. Similarly with limited smoothing options available, employee benefits will also be impacted by lower interest rates which increase the present value of the future liability, increasing annual contribution amounts. The Company is looking at how it can mitigate these increased costs as they directly impact customer rates. In previous contract negotiations, the Company has worked with its Unions to change the benefits payable under the plans or increase employee contributions.

v) Financial

Consistent with the 2012 financing plan, authority has been sought from the Board of Directors to borrow [redacted] This will be sufficient to meet the remaining [redacted] borrowing requirement for 2011, the planned 2012 requirement of [redacted] to meet long term debt maturities in 2012-13, and provide funding for unexpected requirements. To maintain enterprise value and to address the requirements of the capital program, while maintaining financing ratios and the deemed regulated equity structure, common dividends have been managed to maintain the capital structure. [redacted] Payments to the Shareholder through payments in lieu of taxes and dividends, over the Budget period are, [redacted]

For 2012 to 2014, the statutory tax rate has declined from last year's budget based on rates enacted in 2011. The Budget reflects the statutory tax rates of 26.25% in 2012 decreasing to 25.50% and 25.00% in 2013 and 2014, respectively.

This Budget also assumes that work program execution strategies to address identified risks will be successful. These strategies include a variety of initiatives dealing with work program execution, and include the procuring of materials and land acquisition, various regulatory and other required approvals, obtaining funding and the ongoing maintenance of First Nation and Métis relationships.

4. Regulatory Issues

An OEB Decision on Hydro One's request to adopt US GAAP for our Transmission business effective January 1, 2012 is anticipated by the end of November. A similar request will need to be made for US GAAP to also be applicable for distribution as part of the interim rate request. If successful, previously approved transmission rates for 2012 would be approximately 15% lower pending an OEB cost of capital update expected to be announced in November. The plan assumes after Board approval of the reduction that approved transmission rate increase will be 8.2% for 2012.

Similarly, if US GAAP is allowed for regulatory filing purposes for the Distribution business distribution rates will avoid an approximate 14% increase.

If approved by the OEB, the Company's initiative to move its financial reporting to US GAAP basis will have a beneficial impact on reducing customer rates.

A combined cost-of-service application is planned for 2013 and 2014 with proposed Regulated ROEs of 9.7% in 2013 and 10.2% in 2014 based on the application of the OEB's cost of capital report. If approved, transmission rates would increase by approximately 7.0% in 2013 and 10.2% in 2014, (an average of 0.65% increase on the total bill, each year). These increases support aging infrastructure and government supply mix initiatives.

The proposed distribution cost-of-service rate requirements for 2013 [redacted] would decrease rates by approximately 2.7% in 2013 [redacted] No increase is proposed for 2012 with existing rate riders and variance accounts remaining in place until 2013. The increase in 2014 follows an effective rate freeze in 2012 and 2013. Rate increases in 2014 and beyond are driven primarily by additions to rate base and moderate increases to work programs.

5. Financial Accounting Framework

The International Accounting Standards Board, which sets IFRS, did not reach a consensus on whether, when or how regulatory assets and liabilities will be recognized for financial reporting purposes as part of a future standards setting project. In light of this indecision, the Company sought and received an exemption from the Ontario Securities Commission allowing it to file its Consolidated Financial Statements and MD&A in US GAAP for the period January 1, 2012 to December 31, 2014. It is currently unclear what accounting framework will by used in 2015 and later years. If indecision continues with IFRS accounting the Company has the option, in the future, to become a Securities Exchange Commission registrant and continue to file and prepare its financial statements under US GAAP.

For subsidiary reporting, all units except Hydro One Brampton and Hydro One Telecom will also adopt US GAAP. Brampton and Telecom will use IFRS.

US GAAP is very similar to legacy Canadian GAAP (CGAAP) with the exception of minor differences in the presentation of preferred shares on the balance sheet and adjustments related to accounting for employee future benefits costs. The Company's preferred shares, which are held entirely by the Province of Ontario, will be classified as mezzanine equity under US GAAP. In accordance with OEB rate orders, pension costs are recorded under CGAAP when employer contributions are paid to the pension fund in accordance with the *Pension Benefits Act* (Ontario). Pension costs will be recorded in the same way under US GAAP. Employee future benefits other than pension are, and will continue to be recorded on an accrual basis. There are minor differences between Canadian and US GAAP for certain employee future benefits costs. However, Hydro One does not expect any significant change to the net asset position on our Consolidated Balance Sheet. Nor does it expect significant impacts on the Consolidated Statement of Operations following the application of US GAAP to employee future benefits costs.

In addition to the external reporting change, Hydro One Networks has applied to the OEB to have rates set on the basis of US GAAP rather than modified IFRS. A decision is expected at the end of

November. Hydro One Remotes is expected to make a similar request in future. Brampton will retain modified IFRS for rate making purposes.

6. FINANCIAL RESULTS

The adjacent table summarizes key financial results for the 2011 to 2014 period. Revenues, net income, and EBITDA increase over the planning period reflecting a growing rate base in both transmission and distribution as a result of core infrastructure investments.

The financial results support our credit fundamentals and our credit metrics have improved due to the reduction in the capital program. Bearing any negative industry impacts, the Company's "A" credit rating should remain stable.

Dividends are managed to maintain capital structure and enterprise value.

Hydro One Inc. (USGAAP)	2011 Projn	[redacted]
Revenue ($M)	5,467	
Income before PILs ($M)	771	
Net Income ($M)	613	
EBITDA ($M)	1,723	
Cash Flow ($M)	(427)	
Debt Ratio (%)	56%	
FFO Coverage (X)	3.9x	
Total Rate Base ($B)	13,161	
ROE (GAAP) (%)	10.1%	
Capital Expenditures ($M)	1,510	
Dividends ($M)	168	
PILs ($M)	157	
Cash Requirements Incl. Refinancing ($M)	(1,422)	
Long-Term Debt ($M)	8,132	
Regular Staff	5,888	

7. SUBSIDIARY HIGHLIGHTS

7.1 Hydro One Networks – Transmission

Net income and ROE for 2012 reflect the transmission cost-of-service decision rendered by the OEB on December 23, 2010, assuming we are successful with our subsequent request to adopt US GAAP. Net income and ROE for 2013 and 2014 are based on planned cost-of-service applications. Net income is based on assumed rates consistent with the OEB-prescribed formula to calculate allowed returns along with the interest forecast and a rising rate base.

Networks Transmission (USGAAP)	2012 Budget	2013	2014
Net Income ($M)	379	417	470
Regulatory ROE (%)	9.4%	9.7%	10.2%
OM&A ($M)	443	452	460
Capital ($M)	962	1,070	1,089

Our Transmission system is aging and a significant portion of the assets are deteriorating at an increasing rate. Plan over plan, Transmission OM&A expenditures are reduced. Funding limitations will be addressed by implementation of asset analytics to target investment needs. Investments are risk based considering: asset condition; safety; performance; system function; customer impact and statutory requirements. Over the Budget period, Hydro One plans to make investments at several critical stations (e.g. – Manby, Leaside, Cherrywood, Burlington) to ensure operating reliability. Other significant sustainment investments are planned to address asset condition or additional requirements in the following areas:

- Stations – reinvestments to replace end of life equipment, such as air blast circuit breakers, metal clad and gas insulated switchgear

- Replace end of life high voltage underground cables
- Transformer fleet – replace transformers that are at end of life or in poor condition
- Auxiliary telecommunication equipment – replace end of life tone equipment, copper cable and power line carrier systems which are critical elements in the operation of protection systems,
- Stations PCB inspection and testing program required to meet PCB regulations by 2014 extension deadline. The Company remains at risk for completing work programs designed to meet the PCB deadlines.
- Increased investments to comply with NERC cyber security requirements

Transmission development investments over the Budget period are primarily in response to government policy initiatives, system investment needs or customer requirements. Our major capital investments over the Budget period include (net $): Bruce x Milton ($695 million), Commerce Way TS ($43 million), Hearn TS ($101 million), Leaside x Bridgeman 115kV circuit ($76 million), SW Ontario Shunt Compensation Milton TS SVC ($100 million), and a new 500/230kv station at the Oshawa Area TS ($270 million). Transmission investments for Smart Grid and requirements to enable DG are also included in the Budget.

Year-over-year, transmission OM&A expenditures increase marginally from 2012 to 2014 but ramp up in the later years as aging infrastructure needs accelerate. These expenditures address corrective and preventive maintenance, including power transformers (auto and step-down), and regulators as maintenance and mid-life refurbishments on the fleet of approximately 280 high-voltage transmission stations, 29,000 circuit-kilometre high voltage network and 20,700 kilometres of rights of ways are addressed.

Transmission capital expenditures increase from 2012 to 2013 mainly due to increased sustainment investments for system and stations reinvestment to replace end of life air blast circuit breakers, underground cable, auxiliary telecommunications equipment, aging power transformers and to comply with NERC cyber security requirements. These increases are partially offset by decreasing development spending primarily related to Bruce x Milton. From 2013 to 2014, Transmission capital expenditures increase due to the new 500/230kv station at the Oshawa Area TS and increased sustainment spending for system re-investment to replace end of life assets. This is partially offset by the completion of the rebuild of Hearn TS.

7.2 Hydro One Networks – Distribution

Net income and ROE for 2012 reflect no increase to the proposed 2012 distribution rates with existing rate riders and variance accounts remaining in place until 2013. Net income and ROE for 2013 and 2014 are based on planned cost-of-service applications. Net income increases over the period, reflecting the assumed rate changes based on the OEB-prescribed formula to calculate allowed returns along with the interest forecast and a rising rate base.

Networks Distribution (USGAAP)	2012 Budget	2013	[redacted]
Net Income ($M)	237	264	
Regulatory ROE (%)	9.4%	9.7%	
OM&A ($M)	566	582	
Capital ($M)	731	635	

Distribution OM&A expenditures for 2012 to 2014 period are mainly for sustainment programs such vegetation management across the Province, trouble calls and disconnect/reconnect requirements associated with our 123,500 circuit kilometres of low-voltage distribution lines, numerous stations and approximately 1.3 million rural and urban customers.

Consistent with the prior plan, Hydro One's distribution OM&A sustainment work program in 2012 continues to reflect reduced expenditures as per the OEB's decision on our 2010/11 rate application. The reductions were primarily applied to the vegetation management and line maintenance programs, and were scaled to accommodate additional investments in Customer Care that support DG customers and smart metering activity. The total reductions to the vegetation management program do not enable an eight-year forestry clearing cycle. This means that rights of way will contain denser brush that is more costly to manage and has a higher probability of producing tree-related outages. Currently, approximately 50% of customer outages are related to trees. Thus, system reliability could decline as a result of these reductions, and trouble calls could increase. In terms of line maintenance programs, the number of planned defect corrections has been reduced below historical levels. This increases the risk of failures and trouble calls. System reliability will be monitored closely and by leveraging asset analytics tools the limited investments will be prioritized to minimize customer impact while maintaining safety and reliability.

Distribution development capital expenditures over the Budget period are primarily related to Smart Grid development, customer demand work (connections and upgrades), DG connections, including station upgrades, protection and control, new lines and some contestable work for which we receive capital contributions. There is little flexibility with reducing this work as most of it is demand driven.

The roll out of Smart Grid will continue through the 2012 to 2016 period. In 2012, Smart Grid continues to focus on the development of the technical solution and the beginning of its implementation in areas of the Province where operational need is greatest. The early focus will be the integration of the DMS with power system intelligent electronic devices to support embedded DG, but it will also leverage the integration of the existing outage management system and automate crew dispatch.

Plan over plan, the expenditures are significantly reduced. This is in part due to expenditures for DG as these expenditures have been reduced based on the experience gained since 2009 and changes to the FIT Program that have occurred. For the Mid-to Large Non-CAE Projects, the Budget only reflects expenditures for projects with FIT contracts that are expected to connect to Hydro One's distribution system. The Budget also includes expenditures for CAE and MicroFIT projects that are expected to connect.

In 2012, the reductions to sustaining and development are partially offset by a major capital expenditure compared to the last plan in Phase 4 of Cornerstone, which will replace the Company's CIS. The system is near end of life, and costly to maintain and operate. The discovery phase commenced in 2011 with implementation ongoing. The project commenced in 2011 and remains on schedule for go-live in October 2012, with inclusion in rate base in 2013. Under US GAAP the accounting in-service date, and the date when the assets will be included in rate base, is based on the completion of system testing which is expected to occur in 2013.

We continue to focus on support expenditures for the Company as a whole by maintaining salaries and wages consistent with Government guidelines and reductions in non-labour costs to mitigate the impact of the work programs as well as upward pressure from new and emerging obligations.

Distribution capital decreases from the 2012 to 2013 period mainly due to the conclusion of the replacement of the Company's CIS and lower investments for Smart Meters as the program comes to completion. The lower costs are partially offset by the required higher investments for wood pole replacements and the sustainment of distributing and regulating stations as assets continue to age.

The wood pole replacement program increases by roughly $20 million (net) annually from 2012-2016 as the Company increases the investment to replace 15,000 poles on average each year. This addresses an aging population of 1.7 million poles of which 32% are approaching EOL over the next ten years.

Investments in Smart Grid and DG are significant throughout the planning period, but decline as the programs reaches maturity in later years.

7.3 Hydro One Brampton Networks Inc. ("Brampton")

[redacted]

7.4 Hydro One Remote Communities Inc. ("Remotes")

[redacted]

[redacted]

7.5 Hydro One Telecom Inc. ("Telecom")

[redacted]

[redacted]

8. BORROWING REQUIREMENTS

[redacted]

Issuance conditions deteriorated in the second half of 2011 with increasing concerns over Europe's debt crisis and an increased risk of a global recession or slowdown. There are numerous sources of uncertainty that could adversely affect market conditions over the medium term. As such, volatility and intermittent market disruptions are expected to remain a feature in the financing environment for some time. In order to address potential market access risk, flexibility has been requested to borrow [redacted] if market conditions are favourable during 2012 and the cost of carrying funds to refinance debt early is reasonable. In the event the Company cannot issue long-term debt or commercial paper, it will, as a last resort, [redacted]

9. RISKS

As reflected in the Corporate Risk Profile, there are a number of risks that could impact the accomplishment of this Budget. In developing its business plan and Budget, Hydro One has sought to minimize the quantity and magnitude of the risks it faces. Although most of the risks are consistent with prior business plans, the level of certain risks has increased. The newly identified risk sources (Labour Relations Relationship Uncertainty, Outsourcing Risks, Cost Reduction/Productivity and Human Resources Risk) are likely to pose significant challenges.

Labour Relations Uncertainty

Collective Agreements with both the Power Workers' Union and the Society of Energy Professionals expire in 2013. Pursuant to Government direction, the Society of Energy Professionals' contract will be under a net zero guideline. Outcomes of those collective bargaining negotiations will be critical to increasing the effectiveness of the existing cost structure in light of continuing Shareholder and OEB expectations regarding cost reduction. It is also expected that the expiry of the Inergi Outsourcing contract in February 2015 will be of significant interest to the unions as the majority of the Inergi staff are represented by the two unions.

The plan assumes that we can resource the work programs and projects partially by removing indirect positions and replacing them with direct positions. If we do not get the expected level of attrition, or experience labour union pushback, we may not be able to complete the program.

Human Resources Risk
Execution of the plan is contingent upon the Company's ability to obtain the necessary staffing resources. The demand for experienced professional engineers in disciplines such as Protection and Control is high and resources within the Company and available externally with the knowledge of our system are limited. Over the next five plus years, Hydro One faces the possibility of a shortfall of qualified resources as we move forward with the large volume of work to meet asset needs and is faced with the increasing loss of qualified staff due to retirements.

Ignoring eligibility to retire and looking at the current work force who will be 60 and over in each year, currently 328 employees are 60 years of age or older or 6% of the existing work force. In 2012 the number increases to 419 (increase of 91). In 2013, the number increases to 533 (increase of 114). In 2014, the number increases to 688 (increase of 158). In 2015, the number increases to 1,014 (increase of 168) or approximately 18% of the existing work force.

At present, approximately 1 in 4 staff are eligible to retire. Five years from now, more than 1 in 3 could have retired. Although actual retirements have significantly lagged eligibility, the retirement rate has recently increased and could accelerate if the economy improves. Continued compensation freezes, coupled with wage compression with represented staff and future uncertainty may pose an MCP retention risk. Despite the effectiveness of hiring, training, and succession planning, the knowledge loss is likely to be impactful.

First Nations and Métis Relationship Uncertainty remains a very high risk. The expectation is that this risk will likely increase. The United Nations Declaration on the Rights of Indigenous Peoples and the concept of "free prior and informed consent" are increasingly used by First Nations and Métis as leverage for consultation. There is a very real risk that both future work and work in progress could be delayed until First Nations and Métis expectations are met. Recent court rulings continue to support First Nations where First Nations territory or ancestral rights are impacted. Hydro One has a duty to consult where First Nations rights may be impacted. Further, the Shareholder has stated an expectation for First Nations and Métis to become equity partners in energy projects as well as to have employment and procurement opportunities. Hydro One has entered into such a partnership for the purpose of bidding on the East West tie line, however the outcome, complexity and effectiveness of First Nations partnerships as they relate to electricity transmission projects is unknown.

Government policy uncertainty remains a significant risk to the Company. Over the past several years, significant changes have been introduced in the electricity sector. Customer rates have increased dramatically due to the combined impact of rate harmonization, harmonized sales tax, higher costs of power, conservation programs, smart meter costs, higher returns on equity for regulated utilities, and increased investment by electrical utilities in maintenance and capital replacement. The cost of new generation, Green Energy Act costs, and continued investments required to maintain an aging system are likely to increase costs further. Coupled with hotter weather, customers are reacting to the higher costs for electricity. Any significant implications to rates could impact our ability to maintain the network, our ability to maintain our financial fundamentals and could have a detrimental effect on our own productivity and efforts to improve cost effectiveness. Hydro One will continue to consider customer rate impacts, to educate customers on how to be more effective in their use of electricity and to manage customer expectations.

The **Green Energy Act** remains uncertain. The LTEP formed the basis of the Government's Supply Mix Directive, dated February 17, 2011, that directed the OPA to prepare an Integrated Power

System Plan (IPSP). The IPSP requires approval by the OEB and it is unclear when this process will be complete and what the work requirements will be for Hydro One. We are concentrating our efforts on DG and may not be able to react to an unplanned requirement on a timely basis, putting in-service dates at risk.

The DG program also poses significant challenges to Hydro One which could impact the quality, reliability and safety of the system as well as customer satisfaction. Our distribution system was not designed to support large scale connection of Distributed Renewable Generators. For example, it was designed for unidirectional flow. Consequently, reinforcements, protection upgrades and operating tools are being developed to monitor and manage these connections. Our Distribution system does not have the load level consistent with jurisdictions that have distributed generation and it is not clear how the mix of generation formats will work together. The required solutions to connect DG are new to our system and therefore riskier. In addition, the Distribution System Code is not specific as to who pays for upgrades. Additional upgrades may be required after generators are connected. Hydro One has requested and been granted that certain upgrades be funded by all rate payers.

The risk to our ability to fully process all generator applications on a timely basis could continue to be high and is difficult to estimate. Hydro One has developed and executed processes to address connection requirements. However, if volume continues or timelines compress, increases in staff will need to be redirected from the work programs which could impact system reliability.

Infrastructure

Many of our Transmission and Distribution assets are close to or beyond their expected life which could result in a multitude of unexpected equipment failures. In addition, portions of our Transmission system require upgrades to safeguard redundancy in the network and to handle new generation. Property owner resistance to new development as well as First Nations and Métis interests contribute to this risk. Mitigation is provided by higher planning priority for mission-critical parts of the system, real time system monitoring, emergency response capability and stakeholdering with Government agencies and the public on the challenges of new transmission.

As the electrical utility industry moves to automation on the Distribution network the vendor community continually develops digital technologies that leverage IT systems. As Hydro One moves to replace aging infrastructure it is not possible to replace components on a "like-for-like" basis. Hydro One is increasingly more reliant on complex computer technology which is subject to cyber threats and virus attacks. In addition new technologies such as the Advanced Distribution System place considerable dependence on new developing information technology which represents an industry leading way to operate, manage and maintain key distribution assets.

The U.S. Federal Energy Regulatory Commission (FERC) is focused on having the same of level of security and Systems Control and Data (SCADA) that applies to 500KV transmission lines apply to lines with a rating of 100 KV or more. Hydro One is actively participating in two working groups to influence the applicability of these proposed rules. If the new rules are adopted, and if Hydro One is required to adhere to these rules, our costs will increase significantly as we upgrade SCADA and cyber security infrastructure to be compliant.

Customer Relationship

Despite a focus on mitigating customer rate impact, factors both internal and external to Hydro One will continue to exert upward pressure on rates. While CIS is expected to have long term benefits which will increase customer satisfaction, it is considered to be the highest risk Phase of Cornerstone.

The **regulatory environment** that Hydro One faces has become increasingly complex and the demands of the regulators (e.g. ESA, OEB, FERC, NERC) have become more detailed and costly to comply with. At the same time, the OEB has become more aggressive in challenging our costs; as a result there is serious concern regarding our ability to recover the costs needed to sustain our assets. This risk may increase as a result of filing combined cost-of-service applications.

The OEB's *Framework for Transmission Development Plans* policy is being applied to the EWT project. There is concern that this new policy framework may erode our position as the primary builder and operator of Transmission assets in Ontario. To mitigate these risks, Hydro One will file comprehensive rate applications and develop a strategy, including entering into other partnerships, to obtain competitive projects.

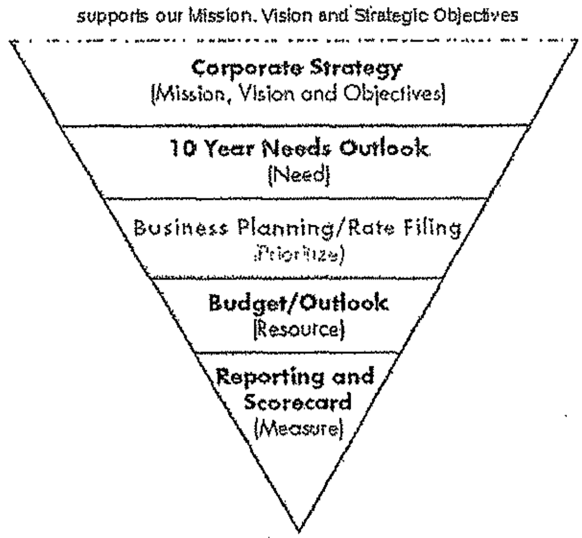
The electricity delivery industry inherently carries a high risk to **worker safety**. In addition to instilling core health and safety values in new employees and apprentices, Hydro One continually stresses the importance of work safety audits, and implements safety initiatives such as Journey to Zero and OHSAS 18001. Safety targets continue to be aggressive, consistent with the belief that an Injury Free Workplace is the only acceptable result.

The Corporate Risk Profile reflects residual risk exposure of the largest credible sources of risk, after consideration of the mitigating controls in place or in progress. There are many other risks which are monitored within the Hydro One Enterprise Risk Management Policy and Framework.

HYDRO ONE STRATEGIC PLAN:
The Five-Year Mission and Vision (2012 – 2016)

Our Strategic Plan builds on the company's strong commitment to the Province of Ontario and is shaped by our Values. It lays out a set of clear objectives to position Hydro One to achieve its Mission and Vision.

In planning and executing our work, everything we do supports our Mission, Vision and Strategic Objectives



Hydro One Inc.
2012 Budget & 2013/2014 Outlook

Peter Gregg
Executive Vice President – Operations

Carmine Marcello
Executive Vice President - Strategy

Sandy Struthers
Executive Vice President and Chief Financial Officer

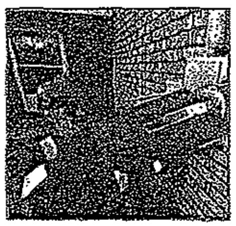
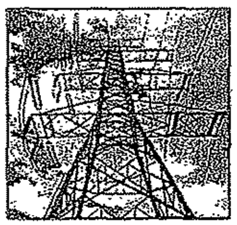
Key Challenges

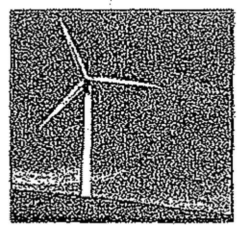
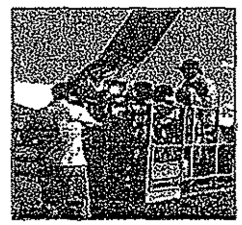
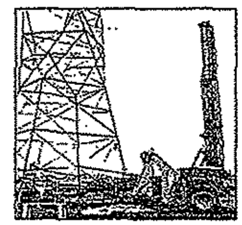
hydroOne

- Budget consistent with strategic goals
- Stable financial results and business profile maintained
  - Impacted by economic risks and concern over increasing rates.
  - Growth in net income.
  - Cash outflow over the long-term due mainly to infrastructure investment.
  - Dividends constrained to ensure enterprise value.
  - Challenges continue in executing Distributed Generation.
  - Uncertainty around Long Term Energy Plan and implications for competitive bidding.
- Budget attains effective balance between work program / asset needs and rate mitigation
  - Resource strategy to deliver growing work program while managing cost and staff levels.
  - Productivity focus to ensure most effective use of assets and cost minimization.

hydroOne

2012 – 2014 Financial Results

Financial Results

hydro One

$M except where noted	Actual 2010	Proj 2011
Revenue	5,124	5,467
Income before PILs	661	771
Net Income	**591**	**613**
EBITDA	**1,572**	**1,723**
Cash Flow	**(533)**	**(427)**
Debt Ratio	57%	56%
FFO Coverage	3.9x	3.9x
Total Rate Base	12,728	13,161
ROE (GAAP)	10.6%	10.1%
Capital Expenditures	**1,570**	**1,510**
OM&A	**1,048**	**1,106**
Dividends	28	168
PILs	70	157
Total Long-term Debt	7,783	8,132
Total Equity	5,981	6,427
Headcount	5,717	5,885

[redacted]

Results in US GAAP

Plan Update

$M except where noted	[redacted]
Revenue (note 1)	
Income before PILs	
Net Income	
EBITDA	
Cash Flow	
Debt Ratio	
FFO Coverage	
Total Rate Base	
ROE (GAAP)	
Capital Expenditures (note 1)	
OM&A (note 1)	
Dividends	
PILs	
Total Long-term Debt	
Total Equity	

$M except where noted	[redacted]
Revenue	
Income before PILs	
Net Income	
EBITDA	
Cash Flow	
Debt Ratio	
FFO Coverage	
Total Rate Base	
ROE (GAAP)	
Capital Expenditures	
OM&A	
Dividends	
PILs	
Total Long-term Debt	
Total Equity	

Note 1: Adoption to US GAAP accounting for overheads capitalized results in approximately [redacted] shift between capital expenditures and operating expenses and the related revenue requirement compared to an IFRS basis.

Business Plan – Projected Cash Flow

	Proj	Outlook	
$ M except where noted	2011	[redacted]	
Cash from Operations	1,251		
Less:			
Dividends	168		
Capital Expenditures			
Sustainment	599		
Development	622		
Green Development/Connection	73		
Other	215		
Total Capital	1,510		
Subtotal	**1,677**		
Cash Flows	(427)		
Less:			
Debt Refinancing	500		
Short Term Refinancing	(173)		
Cash Requirements Including Refinancing	**(754)**		

Results in US GAAP

Long-Term Financial Results

hydroOne

$ M except where noted

	2011	
Revenue	5,467	[redacted]
Income before PILs	**771**	
Net Income	613	
EBITDA	**1,723**	
Cash Flow	(427)	
Debt Ratio	56%	
FFO Coverage	3.9x	
Total Rate Base	**13,161**	
Tx Rate Increase (%)	7.0%	
Dx Rate Increase (%)	8.9%	
Allowed Regulatory ROE	9.7%	
ROE (GAAP)	10.1%	
Capital Expenditures	**1,510**	
OM&A	**1,106**	
Dividends	168	
PILs	157	
Total Long-term Debt	**8,132**	
Total Equity	6,427	

Assumptions

- No Distribution rate increase in 2012.
- Transmission and Distribution joint filing of cost of service in 2013/14.

[redacted]

Results in US GAAP

Long-Term Networks Work Programs

hydroOne

$ M except where noted

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	Avg.
Transmission					[redacted]							
OM&A	440	443	452	460	[redacted]							
Annual Growth		0.7%	2.0%	1.7%	[redacted]							
					[redacted]							
Capital expenditures	846	962	1,070	1,089	[redacted]							
Annual Growth		13.6%	11.3%	1.7%	[redacted]							
					[redacted]							
Distribution					[redacted]							
OM&A	547	566	582	[redacted]								
Annual Growth		3.6%	2.7%	[redacted]								
				[redacted]								
Capital expenditures	611	731	635	[redacted]								
Annual Growth		19.8%	-13.1%	[redacted]								
				[redacted]								
Networks Total				[redacted]								
OM&A	987	1,009	1,034	[redacted]								
Annual Growth		2.3%	2.4%	[redacted]								
				[redacted]								
Capital expenditures	1,457	1,693	1,706	[redacted]								
Annual Growth		16.2%	0.7%	[redacted]								

Assumptions

[redacted]

Results in US GAAP

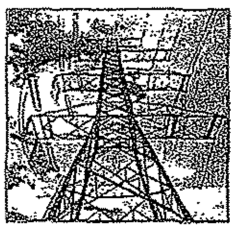
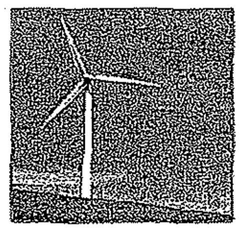
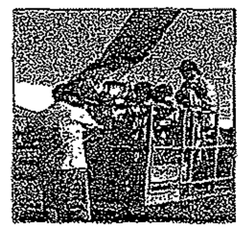
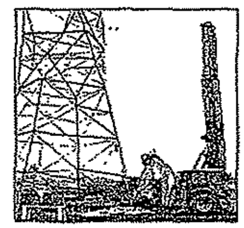
Subsidiaries

hydroOne

[redacted]

Remotes results in US GAAP
Brampton & Telecom results in IFRS

2012 – 2014 Planning Assumptions

Key Planning Assumptions

hydro One

Transmission:

- 2013/14 cost of service application planned in Q2 2012 with rates effective January 1, 2013.
- The reliability of the Transmission System will be maintained at historical levels through the planning period at the proposed investment levels.
- Bruce to Milton project is assumed to be added to the transmission assets with any potential future partnership not reflected in the business plan.
- All costs associated with the East-West Tie Partnership are excluded from the transmission business plan.
- On Niagara Reinforcement Project the OEB approval to collect the allowance for funds used during construction continues while the potential for a change in the project status is being monitored.
- Upgrades at up to 15 transformer stations to enable the connection of small-scale renewable generation are planned as non-recoverable expenses.
- Minister of Energy requested work to begin on three of five priority transmission projects identified in the Long Term Energy Plan, which are included in the business plan.
- Concerns associated with protection complexities of multi-tapped transmission, the pool (not the generator) would fund such additional breakers as are required by the IESO to address system reliability.
- Hydro One will seek recovery from transmission customers and from embedded customers via LDCs the bypass compensation for temporary bypass or permanent stranding of connection facilities.

Key Planning Assumptions

hydro One

Distribution:

- 2012 interim rates being requested to provide rate stability until OEB completes review.
- 2012/13/14 cost of service application planned in Q2 2012 with rates effective January 1, 2012.
- The reliability of the Distribution System will deteriorate slightly through the planning period at the proposed investment levels. Unplanned work may increase.
- New Customer Information System go-live in 2012 and in-serviced in 2013.
- Hydro One will seek from Distribution customers the bypass compensation for temporary bypass or permanent stranding of connection facilities.
- Expansion deposits for subdivisions to be levied effective January 1, 2012.
- Increases are required in the customer systems to the IESO MDMR and to support low income customers LEAP funding and code changes.
- Rate Rider treatment of Smart Grid and Renewable Generation
  - Expenditures from 2012 and onward will be included in the variance account.
  - Generators are responsible for the connection.
  - Expansion and Renewable Enabling investments will be funded in part from all rate payers. Plan is based on the splits provisionally approved in the distribution decision.
  - 2012 variance amounts refunded in 2013/14.
- Request for continuance of variance accounts for Smart Grid, Smart Meters and Renewable generation expenditures through 2014.

Key Financial Assumptions

hydroOne

2012 Plan Economic Assumptions/(2011 Budget)

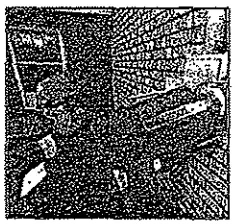
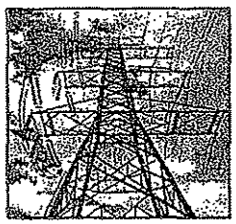
Transmission load growth:	-1.1% (-1.3%)
Distribution load growth:	-0.5% (-1.1%)
CDM: Tx Tariff Impact	$117M ($124M)
Dx Tariff Impact	$50M ($35M)
CPI:	2.1% (2.0%)
Employee benefit costs:	$188M ($173M)
Pension:	$149M ($143M)
Labour escalation:	reflects government guidelines
Income tax rates:	26.25% (28.25%)
Interest rates:	5 yr - 2.90% (3.41%)
	10 yr - 3.94% (4.46%)
	30 yr - 4.96% (5.37%)

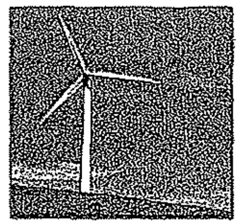
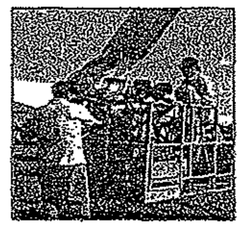
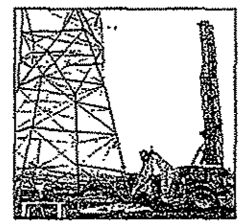
Corporate Risk Profile

hydroOne

Risk Source	Trend (next three years)	Risk Rating July 2011
Government Policy Uncertainty	→	Very High
Customer Relationship Uncertainty	→	Very High
First Nations and Métis relationship Uncertainty	↗	Very High
Labour Unions Relationship Uncertainty	→	Very High
Regulatory Uncertainty	→	High
Employee Injuries	↗	High
Capacity & Architecture of Distribution Assets / Network	→	High
Outsourcing Risks	↗	High
Non-Achievement of Work Program ("Getting the Work Done")	↘	Medium
Information Technology Risk	→	Medium
Inadequate Transmission Asset Condition	→	Medium
Cost Reduction/Productivity Uncertainty	→	Medium
Human Resources Risks	→	Medium

2012 – 2014 Customer Rates

Customer Rate Impacts

hydroOne

		Distribution			
		Total Base and Other Tariff Impact	Rate Rider	Total Tariff Impact	Impact on Total Bill
COS	2012	0.0%	0.0%	0.0%	0.0%
COS	2013	2.9%	-5.6%	-2.7%	-0.9%
	[redacted]				
COS	[redacted]				

- Assumes no rate increase in 2012.
- Clarity on US GAAP approach with OEB expected before end of year.
- Increased base rates are required to address asset growth stemming from government policy initiatives such as smart meters. Sustainment requirements to maintain reliability and address aging assets.
- Timing of Rate Riders reduce impact on Total Bill.

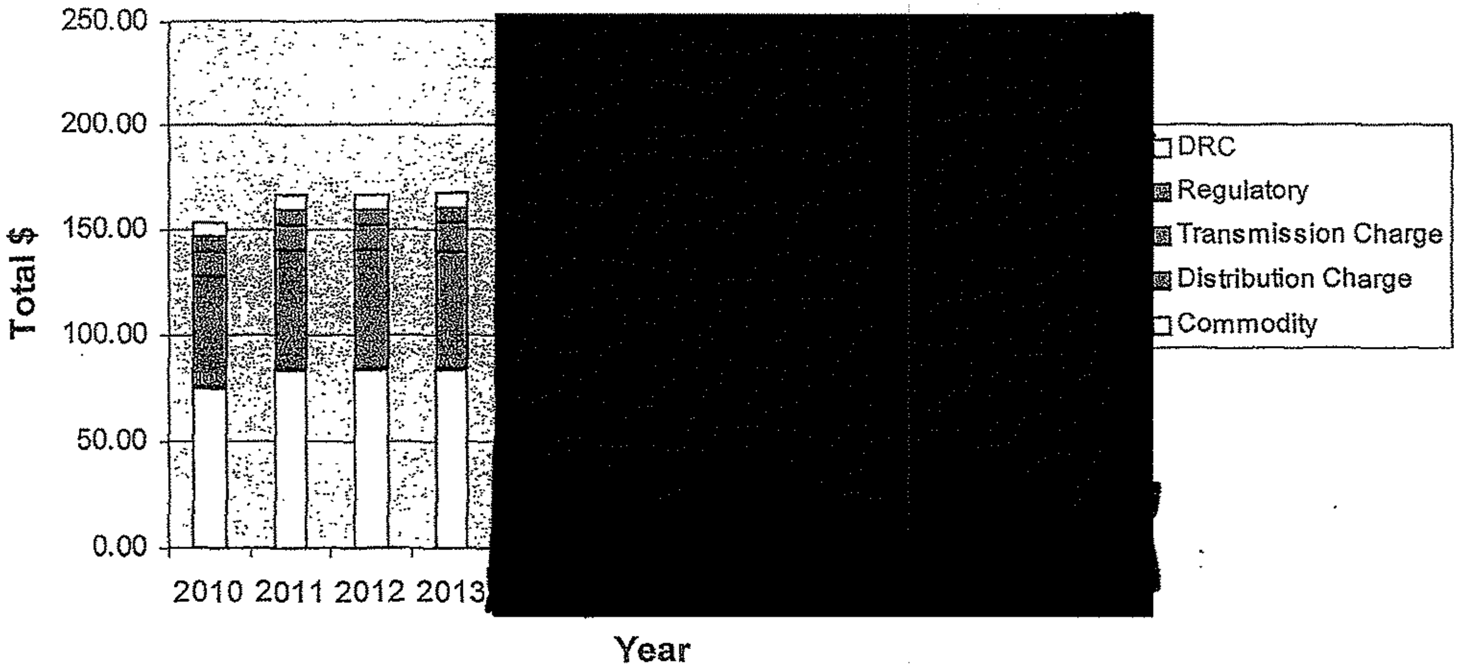
		Transmission			
		Total Base and Other Tariff Impact	Rate Rider	Total Tariff Impact	Impact on Total Bill
COS	2012	7.6%	0.6%	8.2%	0.6%
COS	2013	8.1%	-1.1%	7.0%	0.5%
	2014	10.2%	0.0%	10.2%	0.8%
[redacted]					

- Awaiting OEB cost of capital letter to update 2012 transmission rate order.
- 2013 and 2014 transmission cost of service rate application expected to be filed by Q2 2012.
- Increased rates are required to address government policy initiatives, system investment needs and customer requirements. Sustainment requirements to maintain reliability and address aging assets.

Bill Impacts – Electricity Price

hydroOne

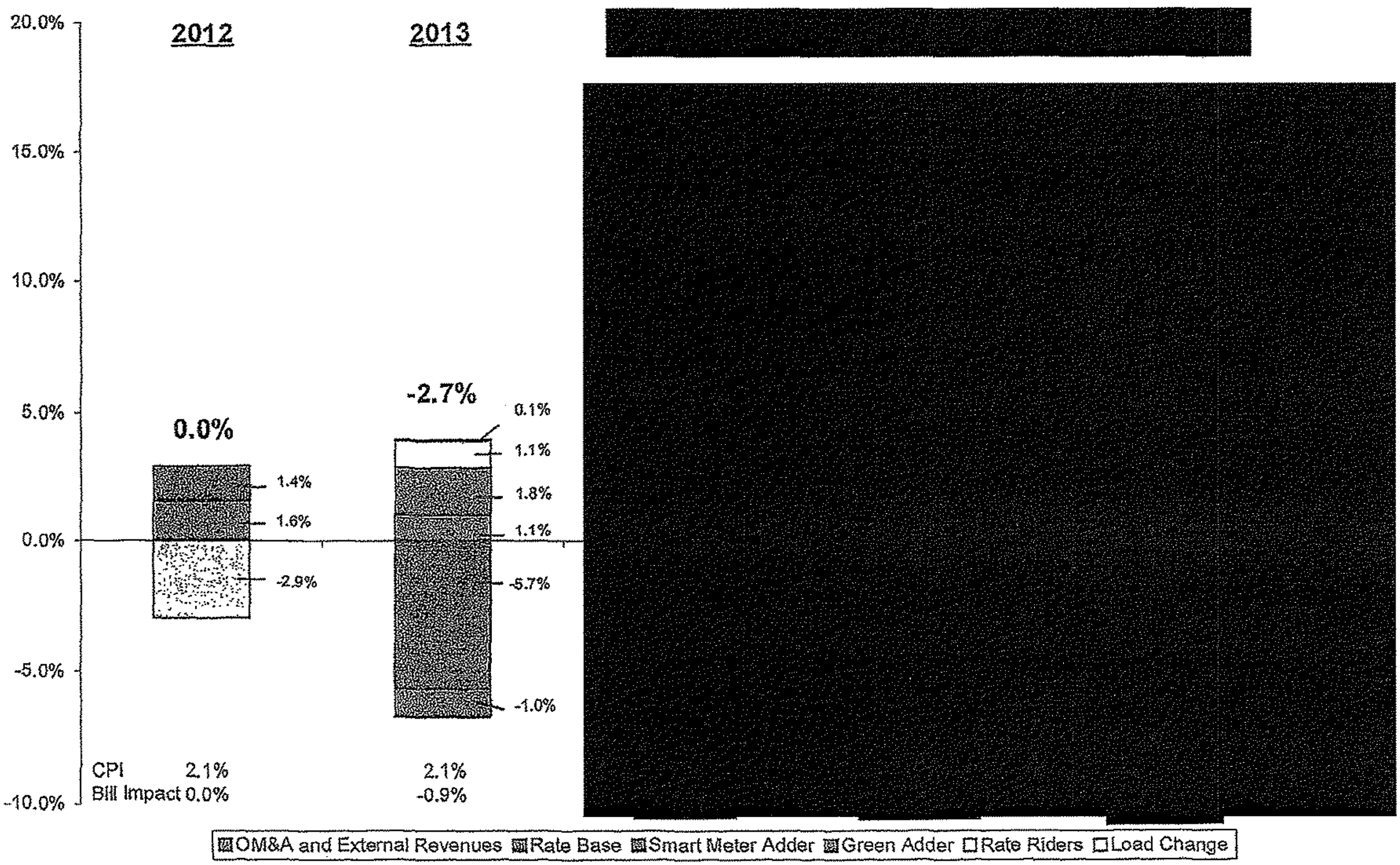
Total Monthly Impact of Transmission and Distribution rate requirements to Typical Residential Customers (based on 1,000 kWh consumption)



	2010	2011	2012	2013	
Total Bill 1,000 kWh	$ 153.21	$ 166.00	$ 166.00	$ 167.09	$ [redacted]
$ Increase			$ -	$ 1.09	$ [redacted]
% Increase			0.0%	0.7%	[redacted]
cumulative			0.0%	0.7%	[redacted]

Note: 2012 Transmission tariff increase is not expected to impact Hydro One Distribution customer bills until 2013.

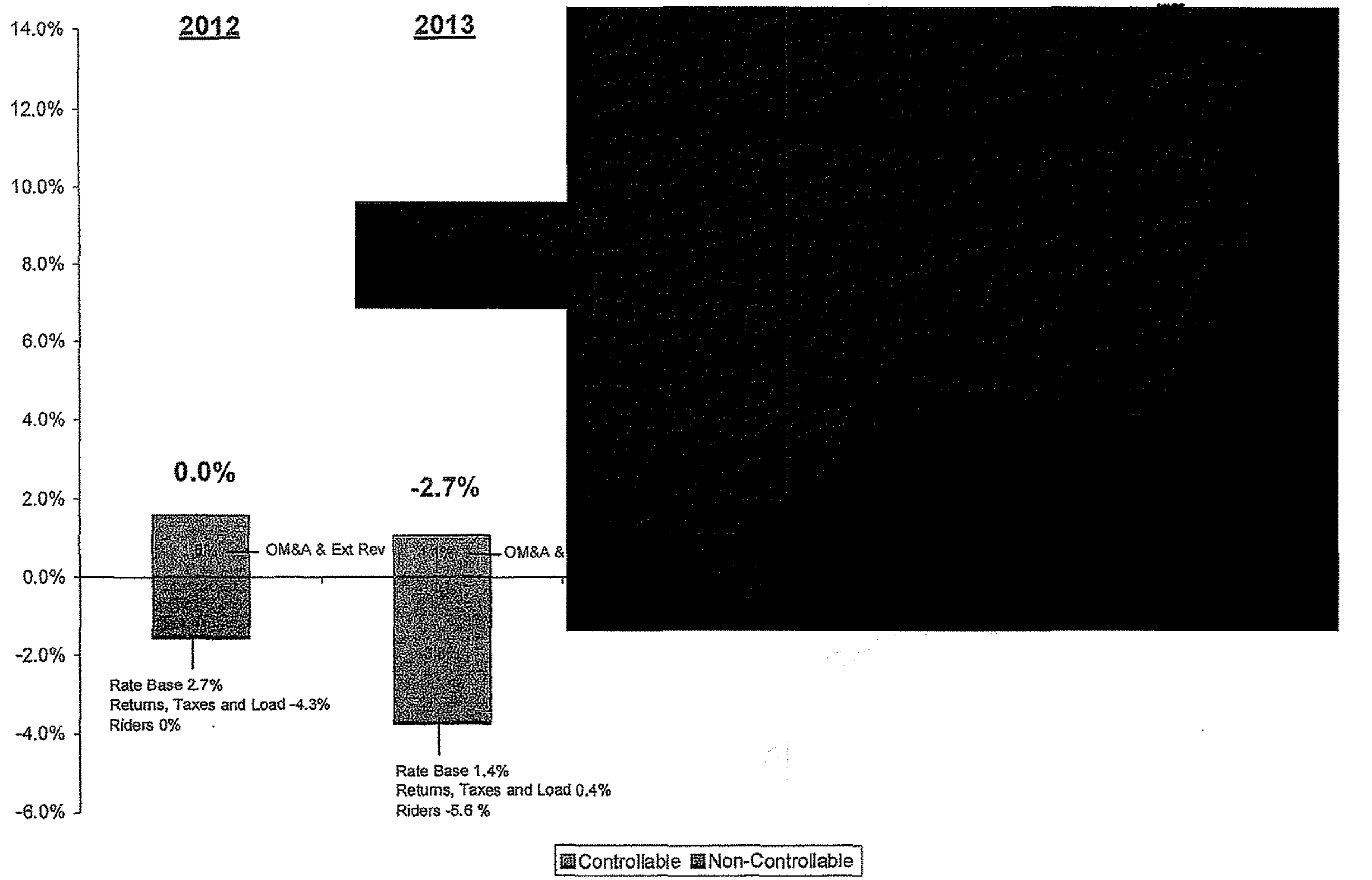
Future Dx Rate Increases



- Rate adders and riders causes changes to rates as collections or refunds begin and end
- Rate base component of rate change increases due mainly to in-servicing of capital projects

Future Dx Rate Increases

hydroOne



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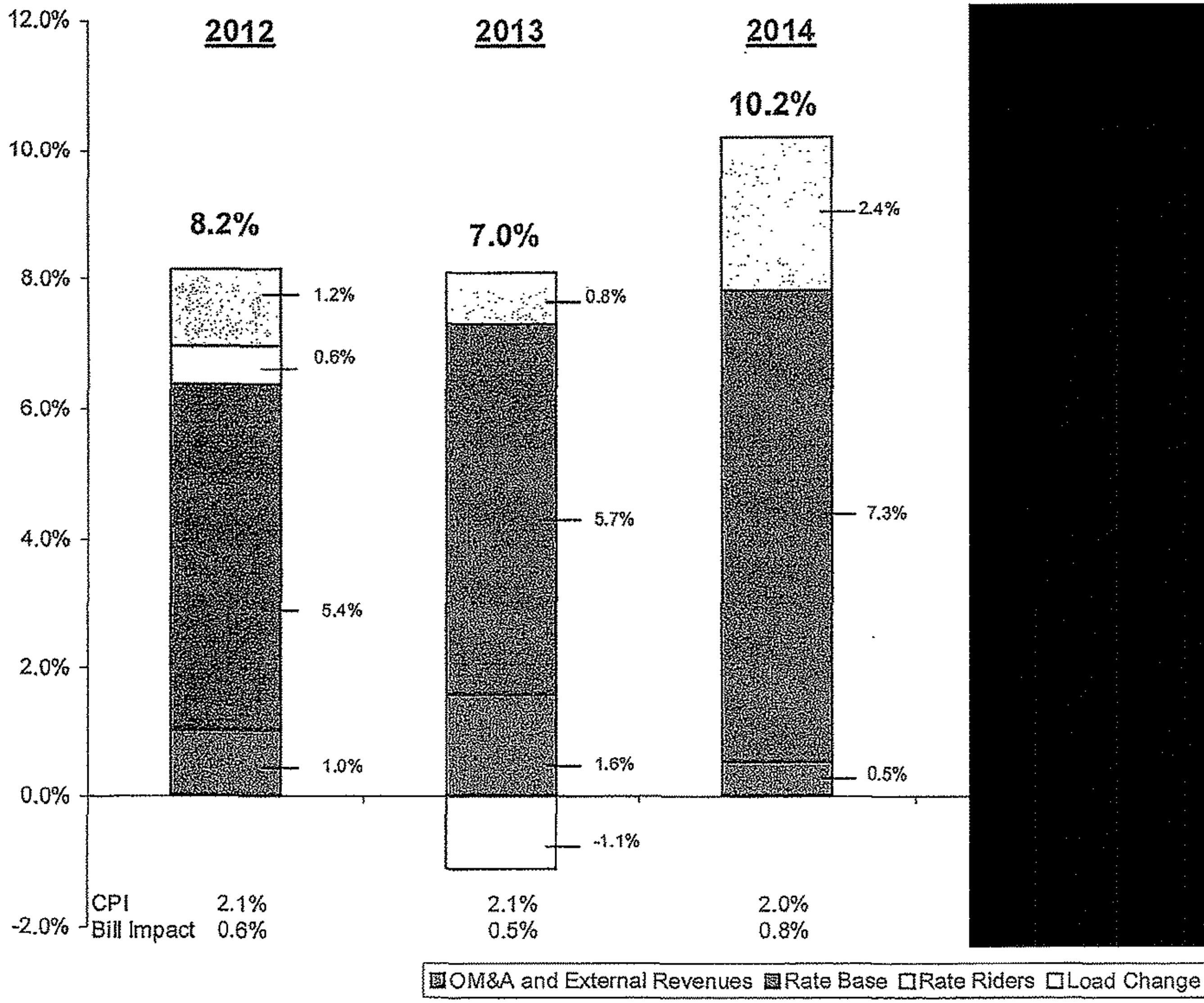
Future Tx Rate Increases

hydroOne



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- Rate adders and riders causes changes to rates as collections or refunds begin and end
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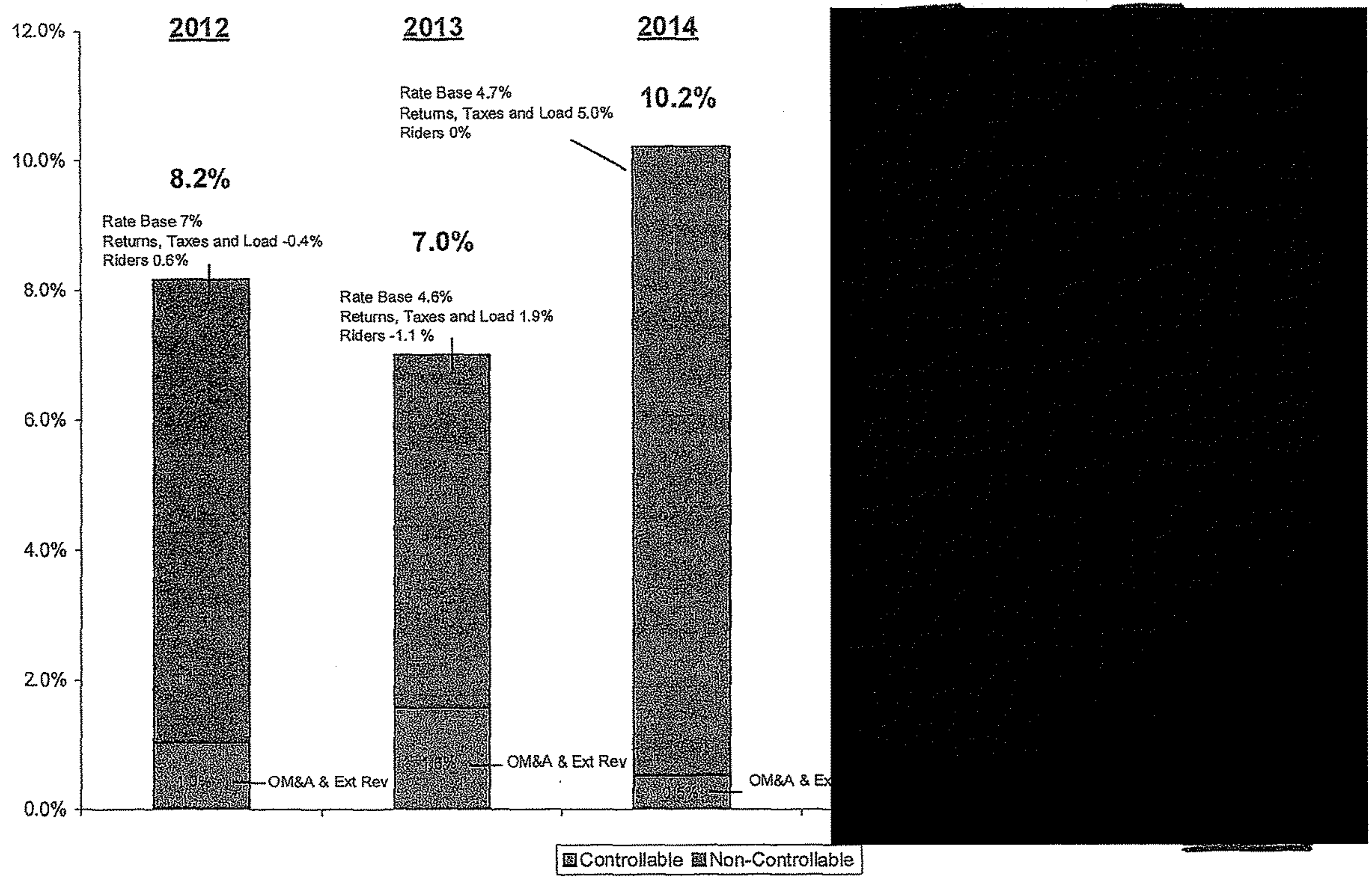
Future Tx Rate Increases

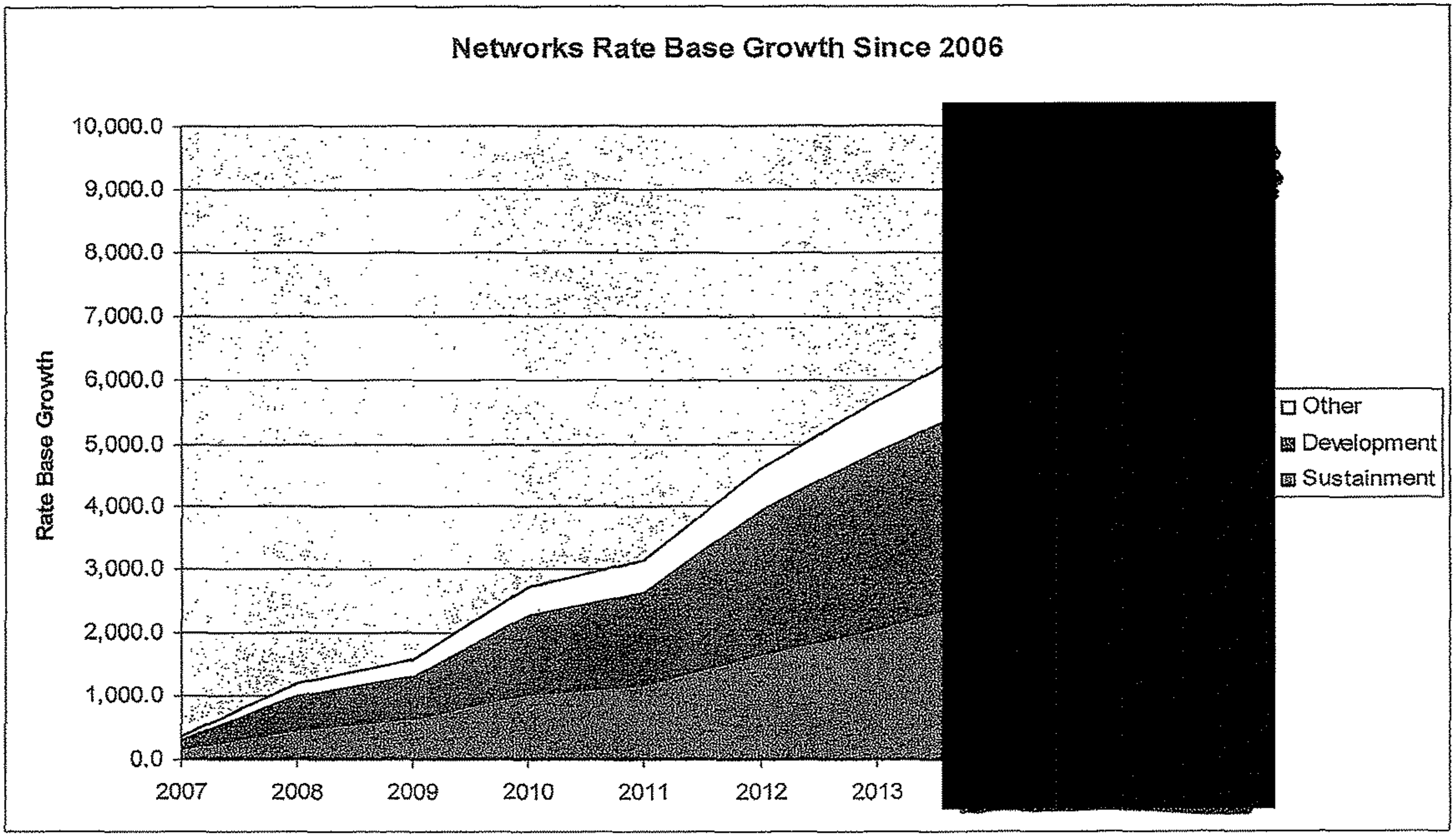
hydro One



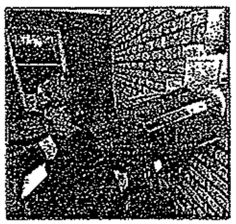
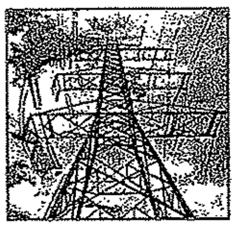
- Rate adders and riders causes changes to rates as collections or refunds begin and end
- Rate base component of rate change increases due mainly to in-servicing of capital projects

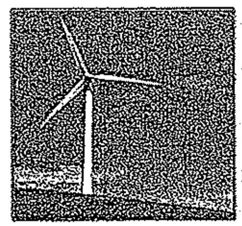
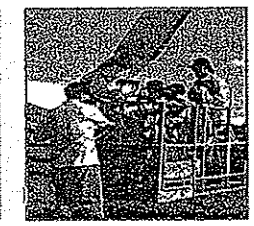
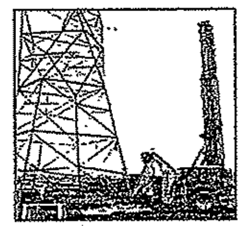
Rate Base Growth Since 2006

hydroOne



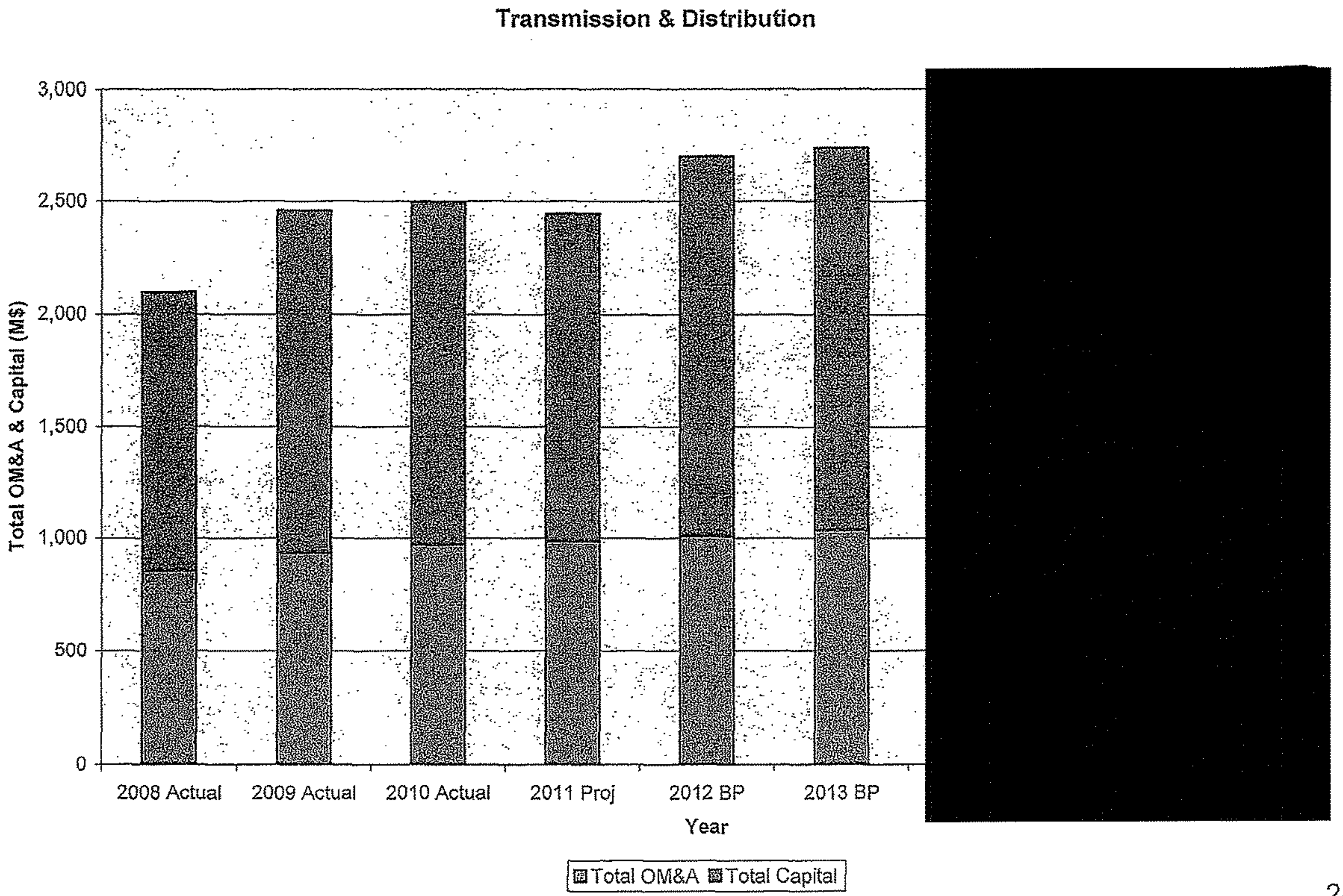
2012 – 2014 Networks Work Programs

Networks Work Program

hydroOne



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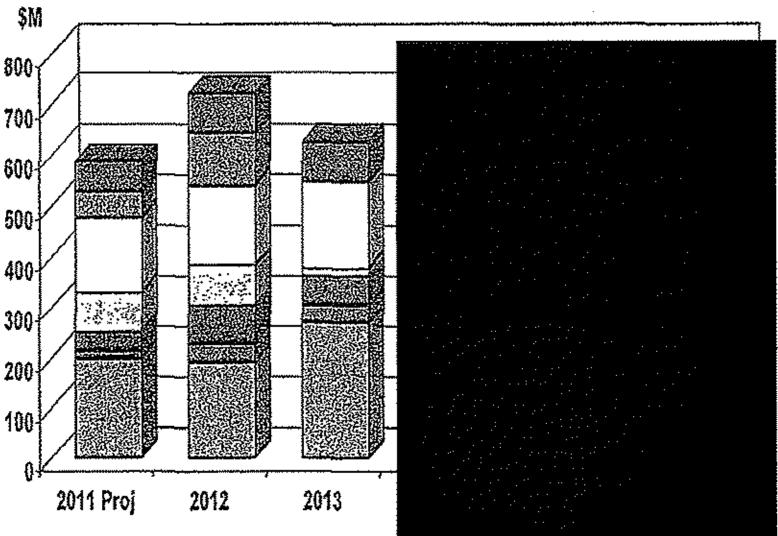
Networks Work Program

hydroOne

DISTRIBUTION CAPITAL



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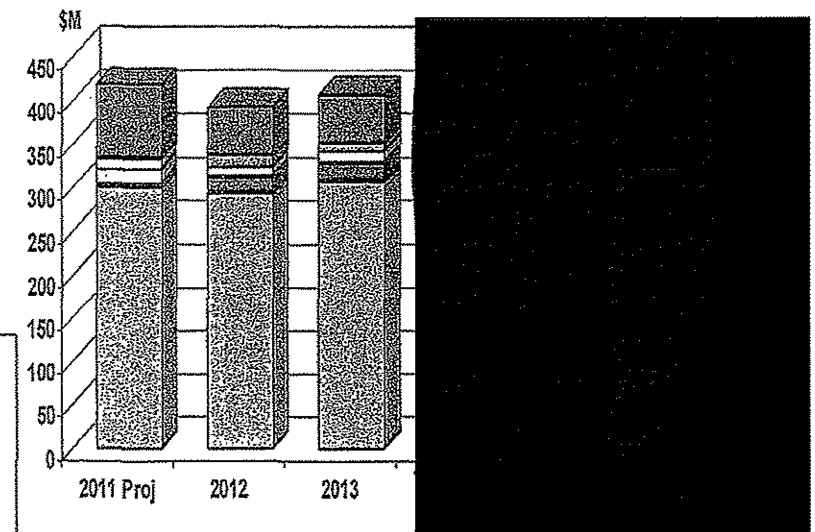
DISTRIBUTION OM&A



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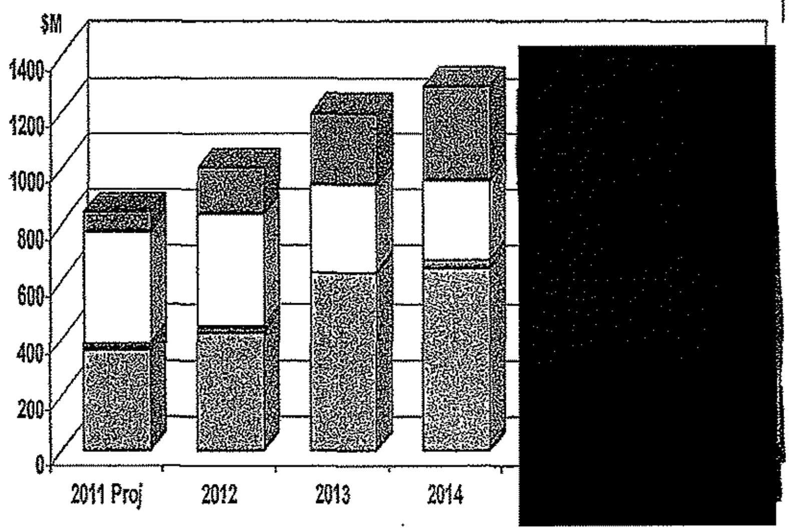
Capital Contribution
CIS
Development
Smart Meters
Smart Grid
Development Green
Sustainment

TRANSMISSION CAPITAL



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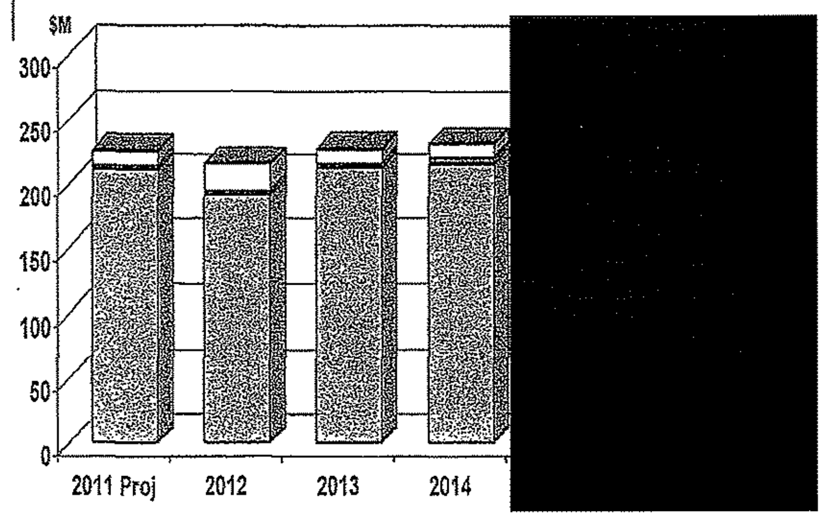
TRANSMISSION OM&A



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Distribution-Sustainment Investments

Dx Sustainment Maintenance
Average 2012-2016 Spend

[redacted]

Dx Sustainment Capital
Average 2012-2016 Spend

[redacted]

- OMA expenditures in 2012 continue to reflect the 2010/11 OEB decision.
- Significant program impacts:
  - Vegetation Management – will not be able to maintain 8 year forestry cycle.
  - Line Maintenance - planned defect corrections reduced below historical levels.
- Capital program increases to offset OM&A reductions and customer demand:
  - Wood Pole Replacements – will increase replacements to address the aging pole demographics, premature decay and offset the defect correct program reductions.
  - Station refurbishment/replacement program increased to address aging assets.
  - Joint Use increased to address demand from Distributed Generation activities.
- System reliability will be supported through the use of Asset Analytics to prioritize work and minimize customer impact.

Distribution-Development Investments

hydroOne

Dx Development Maintenance
Average 2012-2016 Spend

[redacted]

Dx Development Capital
Average 2012-2016 Spend

[redacted]

- Development expenditures are primarily related to customer demand work (connections and upgrades), Distributed Generation connections, Smart Grid and Smart Meters.
- Smart Grid – expenditures to facilitate Smart Zone development and commence rollout of Smart Grid.
- Smart Meters — capital program near completion, sweep behind for last 150K customers. Ongoing maintenance expenditures have been transferred to the appropriate sustainment programs.
- Customer Connections / Upgrades – aim to meet customer requirements within five business days.
- System Upgrade Reinforcement – investments to meet anticipated increase in system load.
- Distributed Generation expenditures decrease over the planning period and reflect the most conservative estimates based on committed projects only.
    - Volumes could fluctuate as connection work is contestable and external approvals have resulted in customers delaying their I/S dates.

Transmission-Sustainment Investments

hydroOne

Tx Sustainment Maintenance
Average 2012-2016 Spend

[redacted]

Tx Sustainment Capital
Average 2012-2016 Spend

[redacted]

- Transmission system is aging and a significant portion of assets are deteriorating at an increased rate.
- Investments are risk based considering: asset condition; safety; performance; system function, customer impact and statutory requirements.
- Investments are planned at several critical stations to ensure operating reliability.
- Other significant sustainment investments include:
  - Stations – reinvestments to replace end of life equipment.
  - Replace end of life high voltage underground cable.
  - Transformer fleet – replace transformers that are end of life or are in poor condition.
  - PCB inspection and testing program required to meet PCB regulations by 2014.
  - Replace end of life auxiliary telecommunications equipment.
  - Increased investment to comply with NERC cyber security requirements.

Transmission-Development Investments hydroOne

Tx Development Maintenance Average 2012-2016 Spend

[redacted]

Tx Development Capital Average 2012-2016 Spend

[redacted]

- Transmission development investments over the planning period are primarily in response to government policy initiatives, system investment needs or customer requirements.
- Major Maintenance investments include:
  - Standards program –updating new/existing standards to meet regulatory requirements/standards.
  - Technology program that will investigate the use of new technologies and/or practices including the ADS program.
- Major capital projects include: Bruce to Milton (I/S 2012), Oshawa Area TS (I/S 2015), Midtown Toronto Infrastructure Renewal (I/S 2013), Commerce Way TS (I/S 2012), Toronto Station Area Upgrades (I/S 2014), Hearn SS (I/S 2013) and Enabling Distribution Generation Connections through transmission upgrades.

Transmission-Common Investments

hydroOne

Tx Common Maintenance
Average 2012-2016 Spend

[redacted]

Tx Common Capital
Average 2012-2016 Spend

[redacted]

- Information Technology – includes Cornerstone Phase 3 initiatives, Inergi support, Business Telecom, application rationalization and streamlining.
- Real Estate & Facilities – includes Transmission portion of Trinity upgrades.
- Fleet – maintain current levels of Fleet and Minor Fixed Assets to support work plan.

Distribution-Common Investments

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Dx Common Maintenance
Average 2012-2016 Spend

[redacted]

Dx Common Capital
Average 2012-2016 Spend

[redacted]

- Customer Care increased as a result of primarily government initiatives including: MDMR Fees, Meter Reading, DG Support Costs, LEAP and Special Investigations.
- Real Estate & Facilities – includes Dx portion of Trinity upgrades.
- Information Technology – includes Cornerstone Phase 3 initiatives, Inergi Support, Business Telecom, application rationalization and streamlining.
- Fleet – maintain current levels of Fleet and MFA to support work plan.
- Customer Information System (CIS) - to be I/S Feb 2013.

Lines & Forestry

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Lines & Forestry Sustainment
Average 2012 – 2016 Gross Spend

[redacted]

Lines & Forestry Development
Average 2012 – 2016 Gross Spend

[redacted]

Gross $M

	2011	2012	2013	
Total Annual Program Spend $M	768	785	845	[redacted]

	2011	2012	2013	
Total Regular Staff #	2,164	2,164	2,164	[redacted]

* Does not reflect staffing conversion of indirect to direct.

Engineering & Project Delivery

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Engineering & Project Delivery Sustainment
Average 2012 – 2016 Gross Spend

[redacted]

Engineering & Project Delivery Development
Average 2012 – 2016 Gross Spend

[redacted]

Gross $M

	2011	2012	2013	
Total Annual Program Spend $M	865	1,066	1,259	[redacted]

	2011	2012	2013	
Total Regular Staff #	659	659	659	[redacted]

* Does not reflect staffing conversion of indirect to direct.

Stations

Stations Sustainment

Average 2012 – 2016 Gross Spend

[redacted]

Stations Development

Average 2012 – 2016 Gross Spend

[redacted]

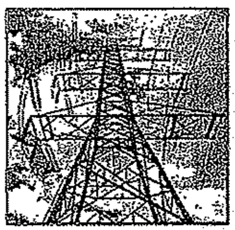
Gross $M

	2011	2012	2013	
Total Annual Program Spend $M	227	197	254	[redacted]

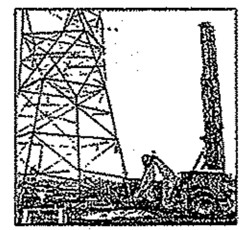
	2011	2012	2013	
Total Regular Staff #	767	767	767	[redacted]

* Does not reflect staffing conversion of indirect to direct.

2012 – 2014 Health & Safety Programs





2012 Health Safety & Environment Program

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Journey to Zero

- Continuation implementation of Journey to Zero initiatives.
- Engage organization in alignment of work program improvement initiatives.

Ergonomic Impacts of employee work activities

- Musculoskeletal Disorder (MSD) prevention.
- Updating of Physical Demands Analysis (PDA's).

Controlled Substance Program

- Development of Lead, Asbestos, PCB and SF6 management programs.

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2012 Health Safety & Environment Program (Contd:)

Arc Flash

- Implementation of program initiatives and identification of new opportunities to mitigate hazard.

OHSAS 18001 Registration

- Target date for registration March 2013.

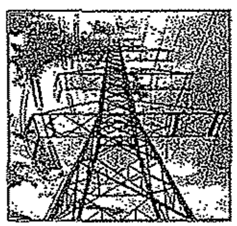
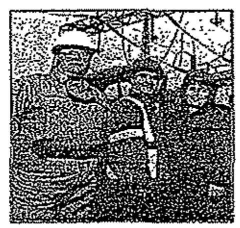
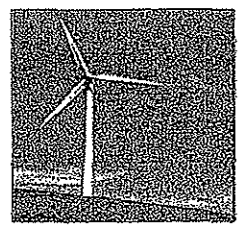
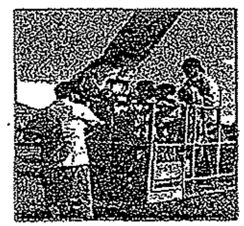
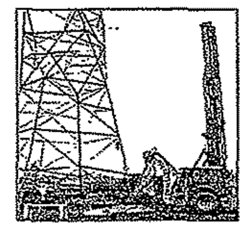
Employee Health and Wellness programs

- Continuation of initiatives that will positively impact employee health and wellness – focus on Mental Health.

Motor Vehicle Accident Prevention

- Implementation of training and other initiatives identified to reduce MVA's.

2012 – 2014 Customer Relationship

The Customer and Our Relationship

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The Customer Mood

- Our customers trust us to deliver on our mandate, but they don't believe we are managing on their behalf – from Focus Group discussion.
- Relationship with the bill: Question how are you spending "my money".
- Need to reset customer relationship and improve trust.
- Maintain rate stability and keep costs increases down.

Resetting the Relationship

- Develop Strategic Relationship Plan which improves relationships with customers, stakeholders and government.
- Establish the voice and messaging for customer approaches for all lines of business for – anywhere we have customer contact.
- CIS will provide analytic and segmenting capability to establish customer profiles and ensure customer communications is targeted, meaningful, and timely.
- Establishes a dialogue rather than one-way communication.

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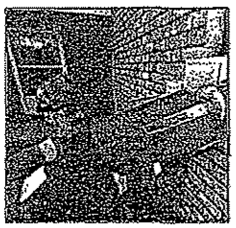
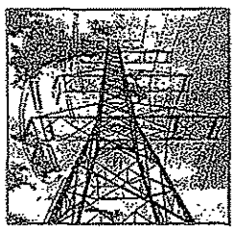
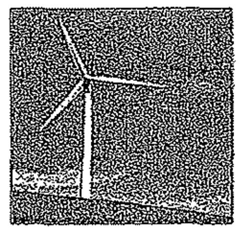
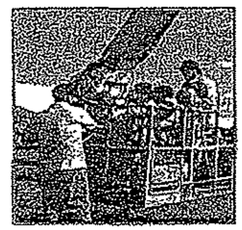
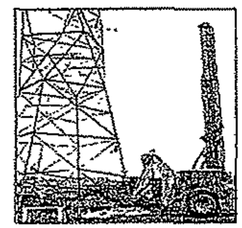
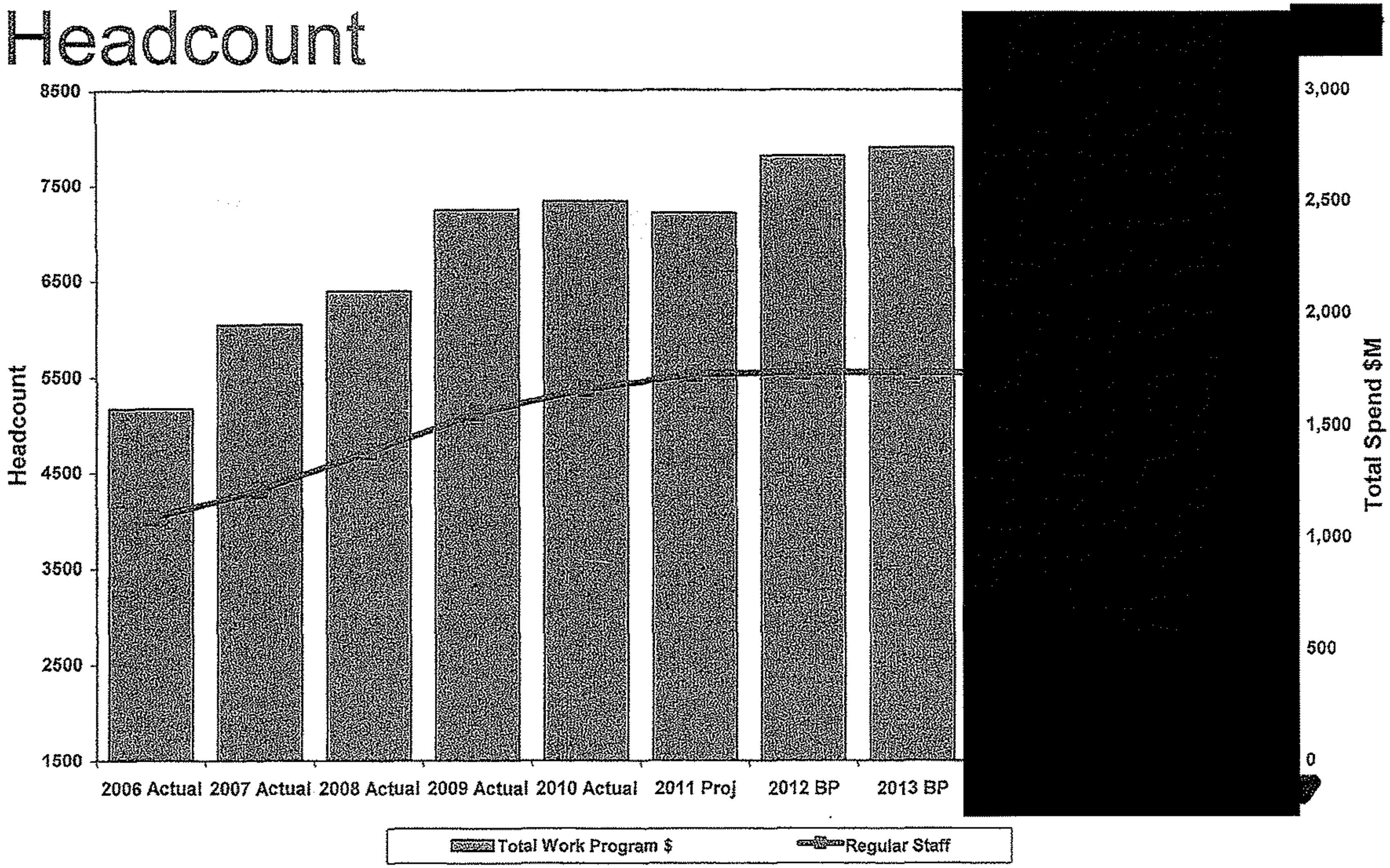
2012 – 2014 Staffing

Networks Work Program Spend and Headcount



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Staffing By Skill Sets

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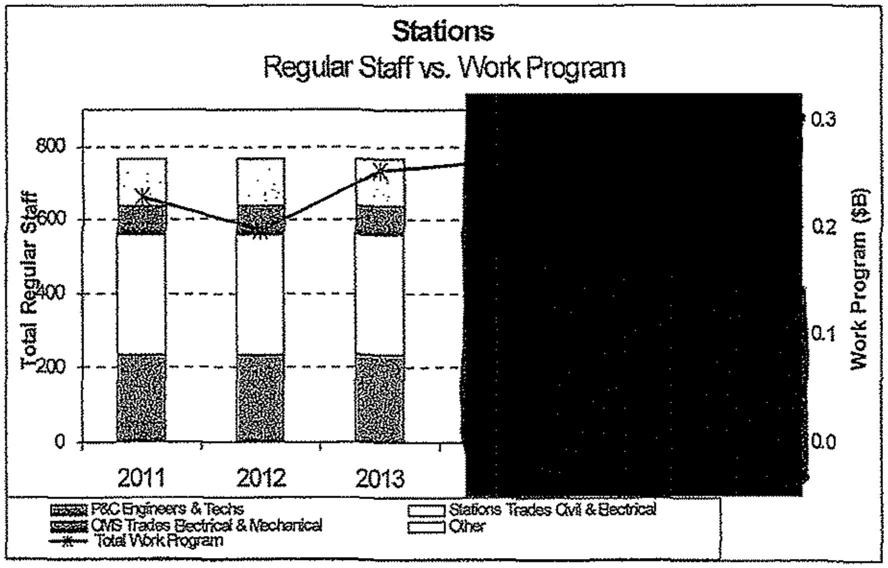

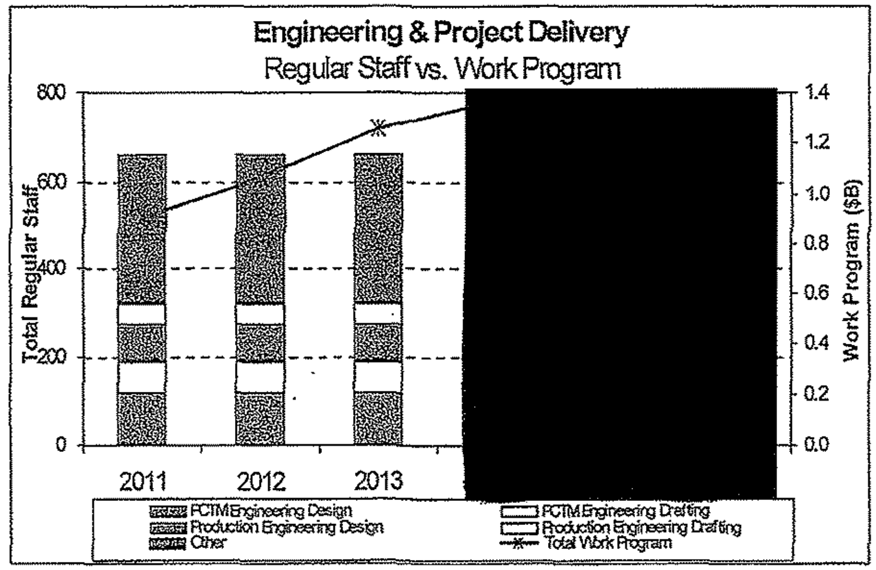

- Work program growth supported by regular, non-regular staff and outsourcing.
- Resource plan addresses replacing vacancies due to retirement and attrition.
- Priority is to hire Protection & Control (P&C) Engineers and technologists to support distributed generation, smart grid and transmission capital. These skills are scarce in the market and require extensive training.
- Provides significant field & commissioning support for many E&PD projects.

- Work program will be achieved through regular and non-regular staff and outsourcing.
- Focus on maintaining a flexible workforce and making resource adjustments to support the executable work.
- Protection & Control (P&C) engineers continue to be in short supply and may be a limiting factor in completing work.
- Succession planning is underway to address work needs and expected attrition.

Staffing By Skill Sets

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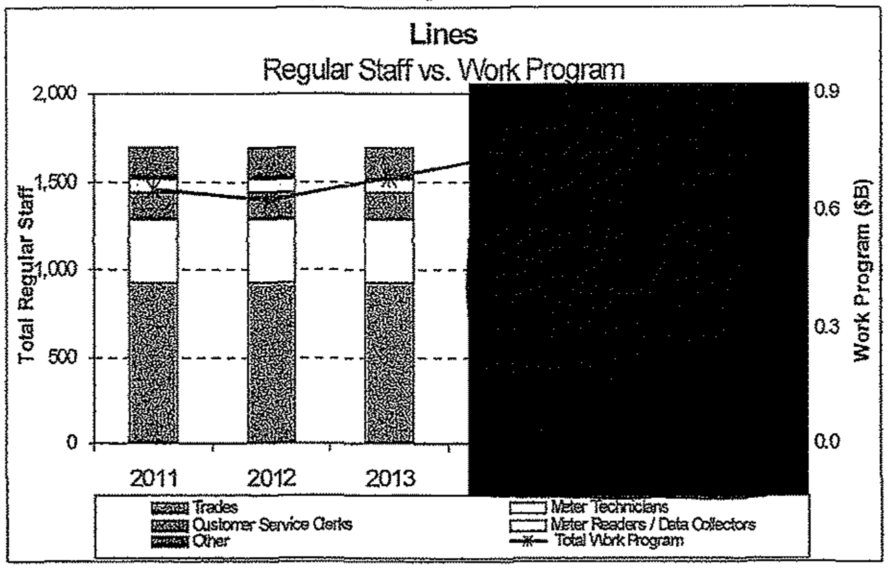

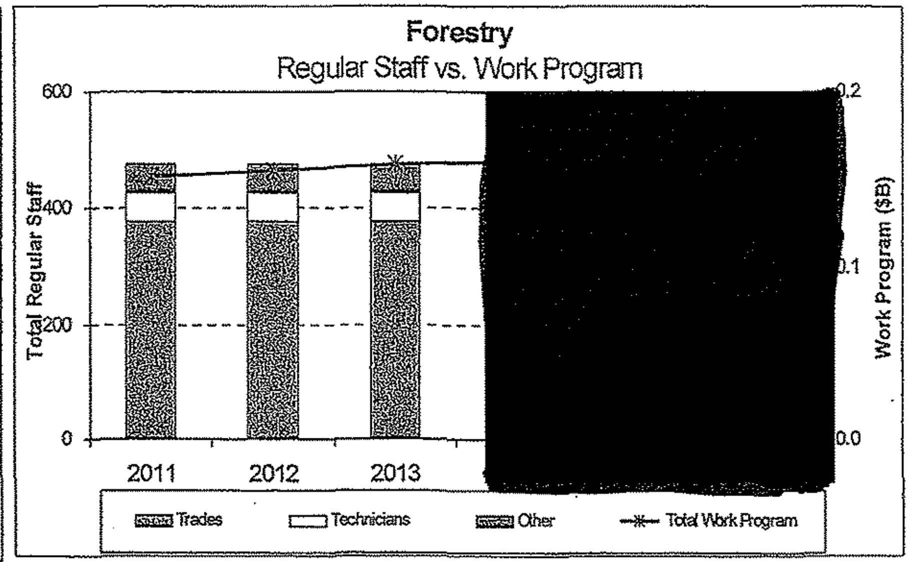

- Work program growth addressed through changes to indirect / direct staff ratio and increased utilization of non-regular staff to provide flexibility.
- 45% of Management and 20% of PWU & Society staff expected to retire in the next 5 years.
- DG work will be completed using Hiring Hall and external contractors.

- Work program growth primarily addressed through the utilization of non-regular staff.
- Regular staff vacancy opportunities due to attrition will be filled by Hiring Hall journeymen, allowing for the continuation of the apprenticeship hiring program.

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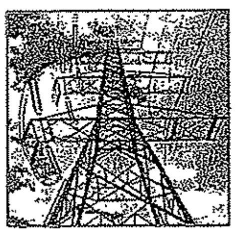
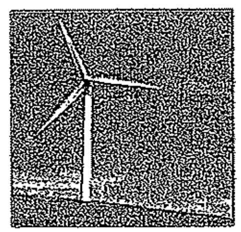
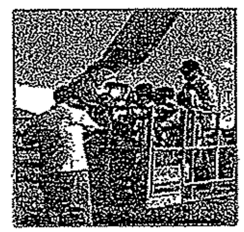
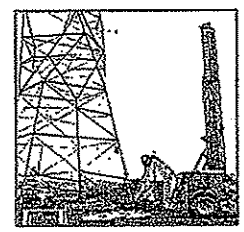
2012 – 2014 Support Costs

Corporate Support – OM&A

	Projection	Business Plan		
OM&A ($Million)	**2011**	**2012**	**2013**	[redacted]
Business Planning & Regulatory Finance	3.0	3.0	2.8	
Corporate Controller	27.0	26.2	26.0	
Treasury	3.0	3.1	3.2	
Corporate Tax	2.0	2.0	2.1	
Human Resources	9.7	9.2	9.4	
Labour Relations	1.4	1.7	1.5	
Regulatory Affairs	20.4	22.4	22.1	
Outsourcing Services	1.7	1.9	1.9	
Total	**68.2**	**69.5**	**69.0**	
Year Over Year Change		**1.3**	**-0.5**	

Inergi Contract Review

- Extension went into effect on May 1, 2010.
- Benefits arising from extensions included:
  - Improved service levels.
  - Revised model in CSO and Help Desk.
  - Large transformation investment by Cap Gemini.
  - More robust termination plan.
  - Reduced cost.
- Work has begun to prepare for next contract.
- RFP early 2013; 2014 handover process (if required).
- March 2015 - New contract begins.

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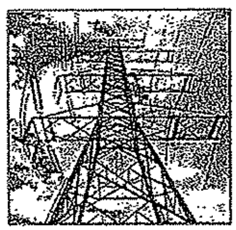
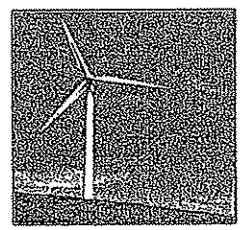
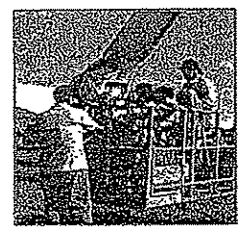
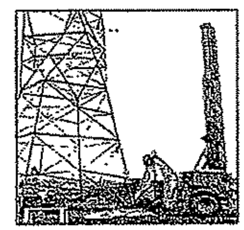
Summary – Inergi results-to-date

- Promised vs. Delivered
  - Improved service levels.
  - Revised (simpler) model in CSO and Help Desk.
  - Large transformation investment by Cap Gemini.
  - More robust termination plan.
  - Reduced cost.

2012 – 2014 Productivity Examples

Productivity & Cost Effectiveness - Examples

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Productivity cost reductions of approximately $280 million across the outlook period (2012-2014) have been embedded in the budget. There are multiple initiatives underway to increase productivity and ensure the effectiveness of investments:

Deployed

- SAP tools are providing the information necessary to more effectively manage work, to optimize investments in the assets and to provide the necessary visibility to managers to enable them to control costs. The original SAP implementations are also providing effective platforms that enable seamless integration of new tools and applications that are supporting greater analytics which enable productivity. Cornerstone phase 1, 2 and the portions of phase 3 that are complete are tracking to plan and are set to deliver approximately $135M in benefits over the outlook period.
- Outsourcing Cost Savings. Additional savings have been achieved through the Inergi renegotiations; including project spend rebates, reduced charges for minor enhancements, and rate card savings. These total approximately $65M over the outlook period.
- Non-labour cost savings enabled by enhancements to telephone, video and web conferencing have reduced the cost and coordination required to effectively communication across the organization while reducing travel expense and time. These total approximately $15M over the outlook period.

In-Progress

- We continue to expand our SAP enabled transformation across the areas of Asset Analytics, Asset Investment Planning, Business Planning, Customer Information Systems, GIS, and ongoing continuous improvement initiatives. These initiatives have a plan to achieve in the range of $50-60M over the outlook period.
- Upgrades to the Wide Area Network to reduce leased line costs and increase bandwidth will result in savings of approximately $8-10M over the outlook period.

Future

- Business Transformational Initiatives: During the period of the Business Plan we will implement new initiatives to drive productivity in the areas of engineering design, work planning, scheduling, dispatch and mobility to further increase productivity and reduce cost.

Productivity & Cost Effectiveness - Examples

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Conceptual Engineering:

- Work with Asset Management to more fully describe the work to be undertaken.
- Element of accountability for AM to understand exactly what is being asked to do
- To identify what work is omitted from the planning specification.
- The functional requirements/specifications will be the AM deliverables with the E&PD technical solution using in-house developed standards as required.

The result is a more focused estimating group producing the estimates in the least number of iterations.

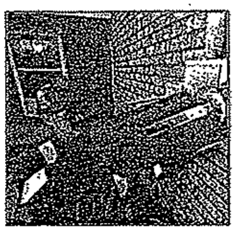
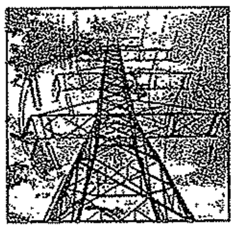
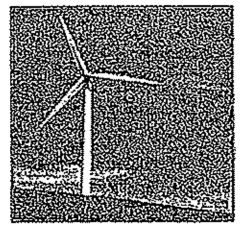
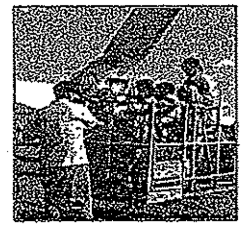
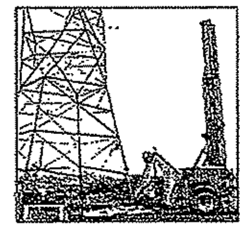
Planning Services:

- Optimal use of Scheduling and Estimating groups.
- PDR production will become more refined.
- The use of Earned Value Management Systems will be driven in to all released work going for board approval.
- Risk analysis and Risk Mitigation for projects will become more pronounced. They will be real considerations of real risks with cause and effects identified as well as remediation methods and cost identified as contingency.

Standards & New Technology:

- The library of standards will grow considerably over the next 2-years and will feed into the Conceptual Engineering process as the solution of first choice.
- This will cascade to Production Engineering reducing the detailed design time enabling the engineers to do work other than "root activities".

2012 – 2014 Financing

Financing Capacity / Capital Structure

- Capital structure maintained close to deemed regulatory level.

- Volatility in forecast capital expenditures from Long Term Energy Plan (LTEP) and Transmission project competition.

- Future capital structure subject to:
  - Volatility in capital expenditures.
  - Potential M&A activity (partnerships).

- Flexibility to use dividends to maintain capital structure.

Financing & Liquidity Requirements

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- Borrowing requirement ranges from [redacted] to [redacted]

- [redacted] of liquidity support comprised of:
  - a [redacted] syndicated standby credit facility maturing June 2014.
  - a [redacted] Liquid Reserve Fund through holding of Province of Ontario Floating Rate Note.

- Liquidity will be maintained, as there is potential upside in forecast capital expenditures.

- Medium Term Note shelf prospectus expires September 2013 - $2.7 billion remaining.

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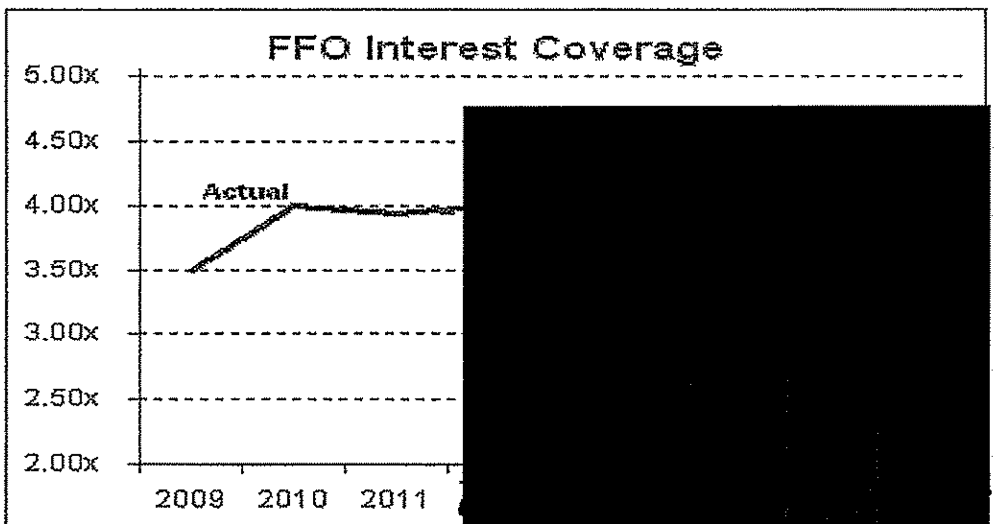
Credit Ratings

- Stable financial profile
  - Capital structure maintained at 40% common equity
  - FFO interest coverage above 3.5x
- Increased business risk
  - Public sensitivity to rate increases
  - Potential political intervention in industry
- Credit ratings should remain stable



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Risk to Credit Ratings

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- Downgrade to Province
- Adverse changes in regulatory environment
- Political intervention
- Deterioration in financial profile

6

Hydro One Inc.
Submission to the Board of Directors

hydroOne

Date: April 5, 2012

Subject: 2012 Budget and Corporate Scorecard Measures Update

Submitted by:

Sandy Struthers
Executive Vice President and
Chief Financial Officer

Approved for Submission to the Board by:

Laura Formusa
President and Chief Executive Officer

RECOMMENDATION

THAT the Board of Directors of Hydro One Inc. ("Hydro One" or the "Company") approve the updated 2012 Budget, including the associated revised Net Income and Corporate Scorecard measures for the year. The 2012 Budget and 2013-2014 Outlook reflect the Company's regulatory filings for 2012 and proposed Transmission and Distribution regulatory filings for 2013 and 2014.

KEY HIGHLIGHTS

- Hydro One received, on March 23rd, approval of its Cost of Service (COS) Distribution application filed December 1, 2011 on a single item requesting the use of US GAAP for its Distribution business commencing January 1, 2012. The use of US GAAP for accounting and regulatory purposes is consistent with the November 2011 approved Business Plan and mirrors the OEB decision for the Transmission business received November 23, 2011.
- The November 2011 Hydro One Board-approved business plan assumed that the Company would file a COS Distribution rate application for 2012 and 2013 and a Transmission COS rate application for 2013 and 2014. The Company will file a Transmission COS rate Application in April 2012 for rates effective January 1, 2013.
- Subsequent regulatory decisions by the OEB, including the approval of the COS Distribution application to record costs in US GAAP and revised cost of capital inputs (i.e. future income tax rate changes), have resulted in the Distribution rate increase being requested for 2012 being below the required regulatory rate threshold for a COS application. As a result, the

Company is subject to an Incentive Regulatory Mechanism (IRM) for Distribution rate making purposes for rates effective January 2012, 2013 and 2014.

- The Company has chosen, at its option and after consideration of the impact on its customers, not to file an IRM application for 2012 and will continue to have its 2011 approved rate schedules apply for 2012. The Company will file IRM applications for 2013 and 2014, the remaining two years of the IRM period, seeking to recover costs and returns associated with the Advanced Distribution System (smart grid) and in-service capital investments. The Company will be required to file a COS application for its Distribution business in 2014 which will rebase its rates effective January 1, 2015
- As a result of these changes in assumptions, and subsequent changes to future income tax rates, the 2012 budgeted revenues will increase by $40 million to $5,658 million and 2012 net income will increase by $29 million to $643 million
- Distribution and Transmission work programs for 2012, 2013, and 2014 remain unchanged from the November-approved Business Plan
- The impact of the changes to the Budget and the Outlook are discussed in the attached Schedule A.
- The 2012 Corporate Scorecard target for Transmission Unit and Distribution Unit Costs remains unchanged at 10.1% (Capital and OM&A per Asset) and $9,900/Km (Capital and OM&A costs per Km of line) respectively. Net Income will increase to $643 million from $614 million.

This Board Memorandum was reviewed and approved for submission to the Board of Directors of Hydro One Inc. by the Audit and Finance Committee at a joint meeting with the Regulatory and Public Policy Committee on April 4, 2012.

EXECUTIVE SUMMARY

1. Strategic Significance

The Budget establishes the level of OM&A and capital expenditures for the year, as well as net income and critical financial metrics. The measures in the Corporate Scorecard are designed to ensure that the corporate strategy is achieved over a specified time period. Net income is measured in the Corporate Scorecard.

2. Purpose

In November 2011, Management stated it would revise and resubmit to the Board of Directors for consideration and approval a revised Budget in the event that decisions were made or events occurred following Board approval that would have a material impact. The Budget and Outlook are now revised to reflect the OEB's decisions with respect to Cost of Capital as it relates to Transmission COS rate applications during the Outlook years and the impact of IRM to Distribution rates during the Budget and Outlook period.

3. Cost Estimate and Recovery

The Appendix includes a schedule which identifies the adjustments made in revising the 2012 proposed budget. A summary of the key financial results is as follows:

$M except where noted	Budget Approved		Change November to April
	[redacted]	[redacted]	
Revenue	[redacted]	[redacted]	[redacted]
Income before PILs	[redacted]	[redacted]	[redacted]
Net Income	[redacted]	[redacted]	[redacted]
EBITDA	[redacted]	[redacted]	[redacted]
Cash Flow	[redacted]	[redacted]	[redacted]
Debt Ratio	[redacted]	[redacted]	[redacted]
FFO Coverage	[redacted]	[redacted]	[redacted]
Actual Rate Base	[redacted]	[redacted]	[redacted]
ROE (GAAP)	[redacted]	[redacted]	[redacted]
Capital Expenditures	[redacted]	[redacted]	[redacted]
OM&A	[redacted]	[redacted]	[redacted]
Dividends	[redacted]	[redacted]	[redacted]
PILs	[redacted]	[redacted]	[redacted]
Total Long-Term Debt	[redacted]	[redacted]	[redacted]
Total Equity	[redacted]	[redacted]	[redacted]

Except as outlined below, the proposed 2012 Budget is consistent with the Budget presented at the November 2011 meeting of the Board of Directors.

[redacted]

4. **Regulatory**

By not filing an IRM application for 2012 Distribution rates, Hydro One's Distribution business will continue to earn revenues in 2012 based on the 2011 approved rate schedules which were derived from the 2011 COS rate revenue application. The 2011 Distribution COS rates were based on a 9.66% regulated Return on Equity, which has since been updated and reduced.

IRM applications will be made for Distribution rates effective January 1, 2013 and 2014. The requested rate increases will be based on the 2011 approved rate schedule and will include a Smart Grid (Advanced Distribution System) adder and seek recovery through an Incremental Capital Module (ICM) rider for incremental in-service additions.

The OEB-approved 2012 Transmission COS application has a 9.42% regulated Return on Equity. In 2013, the revised regulated Return on Equity, based on the OEB updated Cost of Capital calculations, would be 9.16% as compared to the regulated Return of Equity included in the November Board-approved Outlook of 9.70%. In 2014, the revised regulated Return on Equity will be 9.44% as compared to the November Board-approved Outlook of 10.20%

5. **Risk Analysis**

There are a number of risks that could impact the accomplishment of this Budget. These are consistent with the operating and business risks identified in the Budget brought forward to the Board of Directors in November 2011.

The financial impact of OEB decisions with respect to rate applications for the Outlook period will be known in advance as rate decisions are rendered prior to the applicable rate year. Any operating and business risks associated with those decisions will be discussed with the Hydro One Board when they are known.

Schedule A

Hydro One Inc.

2012 Budget and 2013/2014 Outlook (Amended April 5, 2012)

1. INTRODUCTION

The 2012 Budget and 2013/2014 Outlook approved by the Hydro One Board of Directors on November 10, 2011 have been updated to reflect current regulatory assumptions consistent with the proposed rate applications for 2012(no rate application in this year), 2013 and 2014. The impacts of the changes are as noted in the table presented below:

$M except where noted	**Budget Approved**						[redacted]
		[redacted]			[redacted]		[redacted]
Revenue		[redacted]			[redacted]		[redacted]
Income before PILs		[redacted]			[redacted]		[redacted]
Net Income		[redacted]			[redacted]		[redacted]
EBITDA		[redacted]			[redacted]		[redacted]
Cash Flow		[redacted]			[redacted]		[redacted]
Debt Ratio		[redacted]			[redacted]		[redacted]
FFO Coverage		[redacted]			[redacted]		[redacted]
Actual Rate Base		[redacted]			[redacted]		[redacted]
ROE (GAAP)		[redacted]			[redacted]		[redacted]
Capital Expenditures		[redacted]			[redacted]		[redacted]
OM&A		[redacted]			[redacted]		[redacted]
Dividends		[redacted]			[redacted]		[redacted]
PILs		[redacted]			[redacted]		[redacted]
Total Long-Term Debt		[redacted]			[redacted]		[redacted]
Total Equity		[redacted]			[redacted]		[redacted]

This update is consistent with the expectation that if subsequent to the approval of the Budget, information arises or decisions are made that materially impact the original assumptions of the November-approved Business Plan, then the Budget would be revised and resubmitted to the Hydro One Board of Directors for their consideration and approval.

2. CHANGES TO BUSINESS PLAN ASSUMPTIONS

The following significant changes have been made to the Budget and Outlook assumptions as previously presented:

	November 2011	**April 2012**	**Explanation**
Cost of Capital Allowed Return on Equity (Transmission and Distribution)	2012: 9.42% 2013: 9.70% 2014: 10.20% [redacted]	2012: 9.42% 2012: for rates effective after May 1st: 9.12% 2013: 9.16% 2014: 9.44% [redacted]	In February 2012, the OEB updated its cost of capital rates to reflect lower long term bond rates. The updated financial results reflect the OEB's updates to cost of capital parameters as well as revisions to interest rates per the February 2012 consensus forecast.
Rate Application methodology for Distribution Rates	Cost of Service Rate application for 2012 and 2013	No rate application in 2012 – existing approved 2011 rate schedules applied in 2012; IRM application for 2013 and 2014	The Company chose not to file a cost of service rate application in 2012. Approved 2011 rate schedules continue to be applied in 2012 with no rate increase to customers. In 2013 and 2014, the Company will be under an IRM regime. Rates will be rebased in 2015 through a COS application
Corporate Tax Rates	Provincial Corporate tax rates would be reduced to 10% in 2013	Corporate tax rates frozen at 11.5%	Corporate taxes are adjusted pursuant to the March 2012 Ontario Budget
Load Impacts	Declines in load impact would have increased transmission rates by 0.8% in 2013	Revised load forecasts indicate load impacts in 2013 will increase and reduce rates by 0.4%	A load review completed in February 2012 indicates that projected load reductions will not occur as originally forecast

The revised assumptions reflect OEB-mandated changes to the Cost of Capital which are set by the OEB at various points during the year for rates applicable January 1st or May 1st. The Cost of

Capital parameters are used to arithmetically calculate allowed rates of return on equity, interest costs and revenue requirements under a COS filing. The revised amounts reflect the decline in long bond rates which occurred in fourth quarter 2011 and have continued in 2012.

Recent OEB regulatory decisions have confirmed how the OEB would apply rules concerning the application of when an IRM rate regime would be applied. Under these rules, Company would be required to file its distribution rate application for 2012, 2013 and 2014. Under an IRM regime, existing 2011 approved rate schedules are adjusted annually according to a formula which recognizes cost inflation and productivity factors.

[redacted]

3. IMPACT TO 2012 BUDGET

The assumptions underlying the 2012 Budget for the Transmission Business have not changed from the results presented and approved in November 2011 and there has been no material change in the financial results of the Transmission Business for 2012.

[redacted]

While the Company was eligible to file for IRM-based rates in 2012, it chose not to and in so doing saved its customers from the impact a 0.9% tariff increase for which the Company would have been eligible under an IRM application.

With respect to the Corporate Scorecard, small changes recorded in Capital Expenditures and OM&A in 2012 reflect minor changes in respect to the implementation of IFRS at Hydro One Brampton. These changes to Capital Expenditures and OM&A do not impact the 2012 Corporate Scorecard.

4. IMPACT TO OUTLOOK YEARS

The financial performance in the Outlook years for the Transmission Business reflects the change in assumptions noted above. Balances forward for 2013 have also been adjusted to reflect actual and projected in service capital amounts. The resulting impact of the changes in the assumptions, the most significant of which are the lower allowed rate of return and debt costs, higher export credit amounts and higher projected load, is that the requested increase in transmission tariffs for 2013 decline from 7.0% in to 0.8% and as a result of the lower cost of capital assumptions in 2014 requested rates of 10.2% decline to 9.0%.

Embedded within the 2013 Transmission rate application is the use of a new depreciation study which extends the life of the assets and reduces the annual recoverable depreciation expense. If the new depreciation study is not approved, the existing depreciation rates would continue and the tariff increase required would be 2.4%.

The financial performance in the Outlook years for the Distribution Business is most impacted by the requirement that the Company fall under an IRM regime for 2012, 2013 and 2014. During this period, the approved rates are based on the approved 2011 rate schedule adjusted for inflation and a productivity factor. On an annual basis the IRM adjustment to rates is calculated as a 0.9% tariff increase.

The Company did not file in 2012 but plans to file an IRM with an ICM, requesting the recovery of all in-service capital in excess of book depreciation, for 2013 and 2014. The in-service capital requested will be consistent with previous capital spending levels already approved by the OEB in the 2011 Distribution COS application. The net increase in in-service capital in 2013 of $361 million and [redacted] will be sought as an ICM rider and will increase rates by 2.4% in 2013 and [redacted] on top of the IRM adjustment. This is consistent with the position Hydro One is supporting as part of the OEB's Renewed Regulatory Framework initiative.

Hydro One will also request the re-instatement of a smart grid rider to recover the OM&A costs of approximately $20 million for the smart grid program/Advanced Distribution System and the continuation of the associated variance account in 2013. This will add 1.6% to the IRM and ICM rate request for 2013. [redacted]

Distribution Tariffs %	2012	2013	[redacted]		
2013 [redacted] with ICM for all In-service Capital above Depreciation & SG Rider	(0.2)	4.9			
No IRM filing for 2013 or [redacted]	(0.2)	0.0			

hydroOne

2012-14 Business Plan April Update

hydroOne

Approved 2011 Distribution Revenue - Cost of Service Requirement

Cost of Debt
5.39%

Capital Structure
60/40

Cost of Equity
ROE – 9.66%

Rate Base
$4,987M

x

WACC Cost of Capital
7.1%

Return on Capital $354M
+ Income Tax $34M

ROE Net Income $193M
Debt Interest $161M

+

Cost of Service $809M

OM&A $525M
Depreciation $284M

-

External Revenue $48M

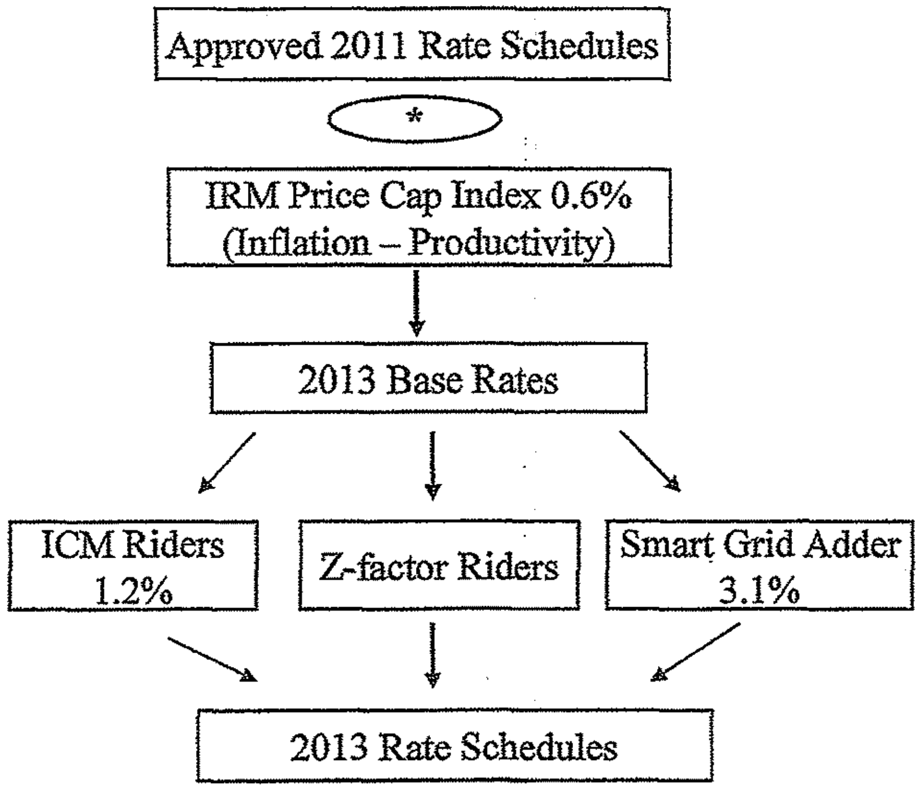
Rates Revenue Requirement
$1,149M

Approved 2011 Rate Schedules

OEB approved	
$ million	
net income	193
PILs	34
Depreciation	284
Interest	161
OM&A	525
External Revenue	(48)
Revenue	1,149
Rate base	4,987
Equity	1,995
ROE	9.66%

2013 Distribution Rates – IRM/ICM

hydroOne



2013 Rate Increase	
Approved 2011 Rates	Base
PCI Adjustment	0.6%
2013 Base Rates	0.6%
ICM Riders	1.2%
Z-Factor Riders	0
SG Adders	3.1%
2013 Rate Increase	4.9%

Summary of Assumptions

- Transmission cost of service in 2013/14, 2015/16
- No Distribution cost of service in 2012
- Distribution IRM/ICM in 2013/14, cost of service in 2015/16
- Plan updated to reflect 2011 actual results
- Revised ROE per February 2012 consensus forecast
  - 2013: 9.16% (9.70% Nov Board)
  - 2014: 9.44% (10.20% Nov Board)
  - [redacted]
- Revised interest rates per February 2012 consensus forecast
- Revised load forecast, LVSG and Export Credit assumptions
- [redacted]
- OEB approval of US GAAP request for Dx
- Ontario corporate income tax rate frozen at 11.5%

April Update - Financial Results

hydroOne

$M except where noted	Actual 2010	Actual 2011	[redacted]
Revenue	5,124	5,471	
Income before PILs	661	790	
Net Income	**591**	**641**	
EBITDA	**1,572**	**1,751**	
Cash Flow	**(533)**	**(304)**	
Debt Ratio	57%	55%	
FFO Coverage	3.9x	4.2x	
Actual Rate Base	12,728	13,527	
ROE (GAAP)	11%	10.5%	
Capital Expenditures	**1,570**	**1,447**	
OM&A	**1,048**	**1,069**	
Dividends	28	168	
PILs	70	150	
Total Long-term Debt	7,783	8,008	
Total Equity	5,981	6,454	
Headcount	5,717	5,781	

Results in US GAAP

Change from Nov Board: Financial Results

hydroOne

$M except where noted	Actual 2010	Actual 2011	[redacted]
Revenue	0	4	
Income before PILs	0	20	
Net Income	**0**	**27**	
EBITDA	**0**	**28**	
Cash Flow	**0**	**122**	
Debt Ratio	0%	0%	
FFO Coverage	0.0x	0.2x	
Actual Rate Base	0	48	
ROE (GAAP)	0.0%	0.4%	
Capital Expenditures	**0**	**(63)**	
OM&A	**0**	**(37)**	
Dividends	0	0	
PILs	0	(8)	
Total Long-term Debt	0	(124)	
Total Equity	0	27	
Headcount	0	(104)	

Results in US GAAP

April Update: Long-Term Financial Results

$ M except where noted

	2011	[redacted]
Revenue	5,471	
Income before PILs	**790**	
Net Income	641	
EBITDA	**1,751**	
Cash Flow	(304)	
Debt Ratio	55%	
FFO Coverage	4.2x	
Actual Rate Base	**13,527**	
Tx Rate Increase (%)	7.0%	
Dx Rate Increase (%)	8.9%	
Allowed Regulatory ROE	9.7%	
ROE (GAAP)	10.5%	
Capital Expenditures	**1,447**	
OM&A	**1,069**	
Dividends	168	
PILs	150	
Total Long-term Debt	**8,008**	
Total Equity	6,454	

Assumptions

- No Distribution cost of service in 2012.
- Distribution IRM-ICM 2013/14, cost of service in 2015/16.
- Transmission cost of service in 2013/14, 2015/16.

[redacted]

Results in US GAAP

Change from Nov Board: Long-Term Financial Results

hydroOne

$ M except where noted

	2011	[redacted]
Revenue	4	
Income before PILs	**20**	
Net Income	27	
EBITDA	**28**	
Cash Flow	122	
Debt Ratio	0%	
FFO Coverage	0.2x	
Actual Rate Base	**48**	
Tx Rate Increase (%)	0.0%	
Dx Rate Increase (%)	0.0%	
Allowed Regulatory ROE	0.0%	
ROE (GAAP)	0.4%	
Capital Expenditures	**(63)**	
OM&A	**(37)**	
Dividends	0	
PILs	(8)	
Total Long-term Debt	**(124)**	
Total Equity	27	

Results in US GAAP

Customer Rate Impact

		Distribution			
		Total Base and Other Tariff Impact	Rate Rider	Total Tariff Impact	Impact on Total Bill
No COS	2012	0.0%	-0.2%	-0.2%	-0.1%
IRM/ICM	2013	3.2%	1.6%	4.9%	1.6%
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

		Transmission			
		Total Base and Other Tariff Impact	Rate Rider	Total Tariff Impact	Impact on Total Bill
COS	2012	7.2%	0.6%	7.8%	0.6%
COS	2013	1.8%	-1.1%	0.8%	0.1%
	2014	9.2%	0.0%	9.2%	0.7%
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Tariff impacts

	Without riders		with riders	
	Dx	Tx	Dx	Tx
2012	0.0%	7.2%	-0.2%	7.8%
2013	3.2%	1.8%	4.9%	0.8%
2014	[redacted]	9.2%	[redacted]	9.2%
average	[redacted]	6.1%	[redacted]	5.9%

Total Bill Impact

	Dx	Tx	Total
2012	-0.1%	0.6%	0.5%
2013	1.6%	0.1%	1.7%
2014	[redacted]	0.7%	[redacted]
average	[redacted]	0.4%	[redacted]

Transmission

Tx: Long-Term Financial Results

$ M except where noted

	2011 COS	2012 COS	2013 COS	2014 COS	[redacted]
Revenue	1,391	1,429	1,469	1,563	
Income before PILs	**457**	**440**	**439**	**491**	
Net Income	379	383	390	433	
EBITDA	**956**	**985**	**1,017**	**1,104**	
Cash Flow	(236)	(481)	(576)	(529)	
Debt Ratio	56%	57%	59%	60%	
Actual Rate Base	**7,877**	**8,649**	**9,460**	**10,073**	
Tx Rate Increase (%)	7.0%	7.8%	0.8%	9.2%	
Allowed Regulatory ROE	9.7%	9.4%	9.2%	9.4%	
ROE (GAAP)	10.6%	10.1%	9.8%	10.5%	
Capital Expenditures	**810**	**962**	**1,070**	**1,089**	
OM&A	**434**	**444**	**452**	**460**	
PILs	77	56	50	58	
Total Debt	**4,845**	**5,323**	**5,895**	**6,422**	
Total Equity	3,823	3,984	4,157	4,324	

Assumptions

- Transmission cost of service in 2013/14, 2015/16.

[redacted]

Results in US GAAP

Tx Summary of Key Changes

hydroOne

April Update:

•ROE: 9.16% (2013), 9.44% (2014), [redacted]

•Load impact on rates in 2013 of (-0.4%)

•Export credit estimate of $31M

•2011 Actuals updated

•Ontario budget freezes provincial income tax rates at 11.5%

November Board:

•ROE: 9.70% (2013), 10.20% (2014), [redacted]

•Load impact on rates in 2013 of (+0.8%)

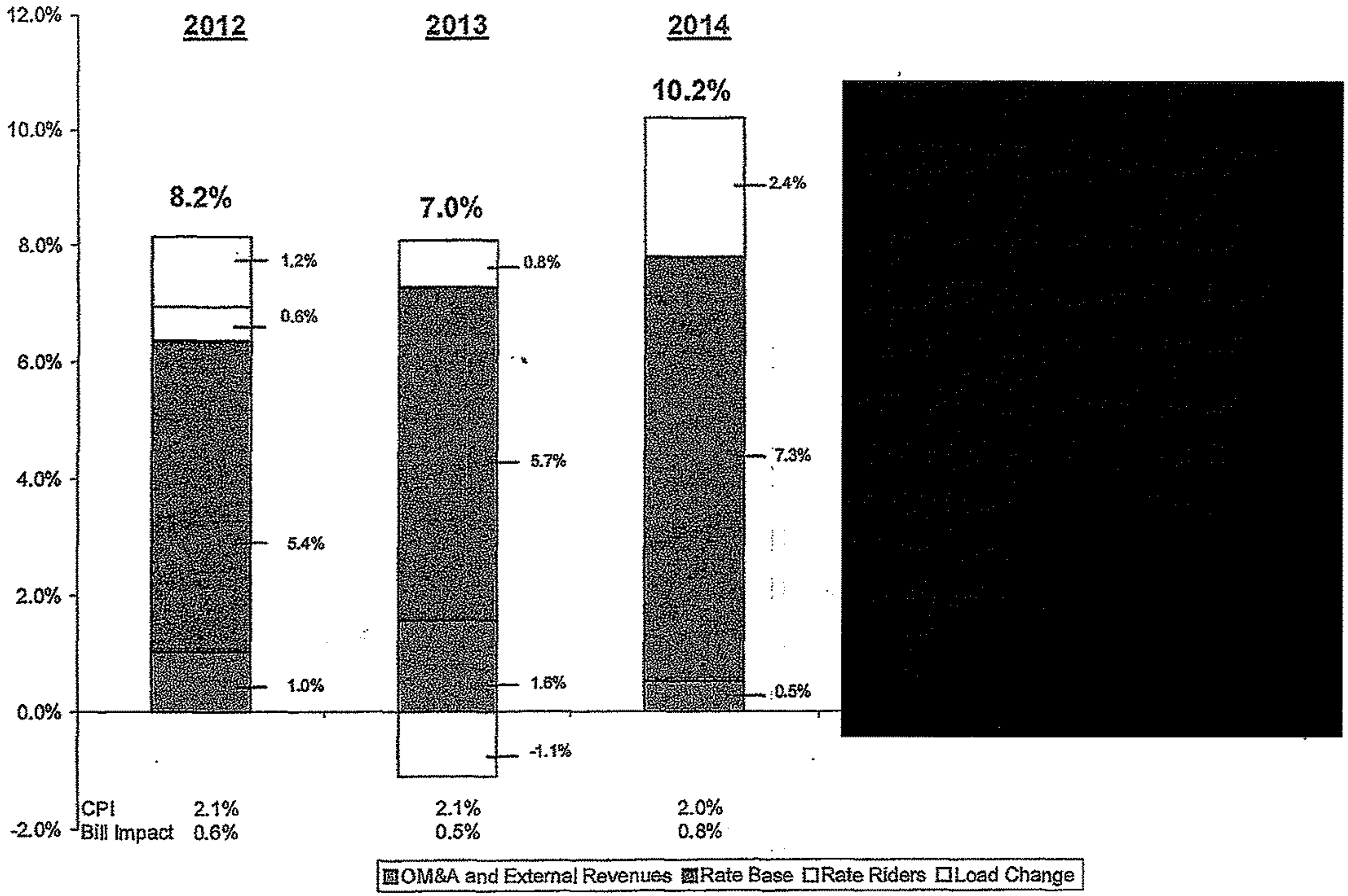
•Export credit estimate of $16M

•2011 Forecast

•Ontario provincial income tax rates declining to 10% in 2013

Tx Rate Increase: Nov Board

hydroOne

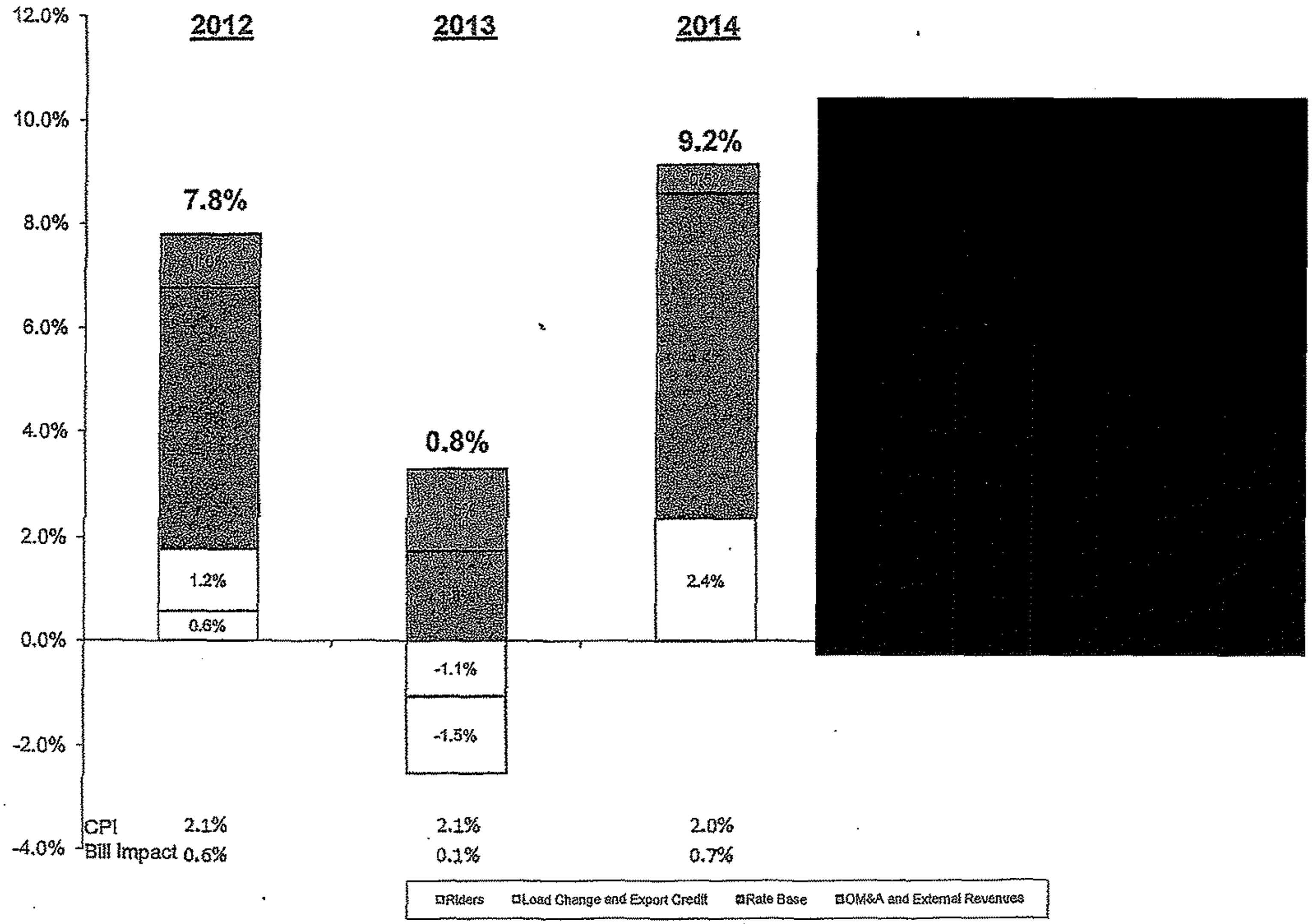


- Rate adders and riders causes changes to rates as collections or refunds begin and end
- Rate base component of rate change increases due mainly to in-servicing of capital projects

Tx Rate Increase: April Update

hydroOne

Updated for Ontario budget change to Provincial Tax Rates



14

hydroOne

Distribution

Dx: Long-Term Financial Results

hydroOne

$ M except where noted

	2011 COS	2012 No File	2013 IRM	[redacted]
Revenue	3,569	3,726	3,783	
Income before PILs	**302**	**300**	**320**	
Net Income	236	260	289	
EBITDA	**729**	**739**	**795**	
Cash Flow	(3)	(503)	(168)	
Debt Ratio	56%	59%	58%	
Actual Rate Base	**5,311**	**5,643**	**6,077**	
Dx Rate Increase (%)	8.9%	-0.2%	4.9%	
Allowed Regulatory ROE	9.7%	9.4%	9.2%	
ROE (GAAP)	11.8%	12.1%	12.7%	
Capital Expenditures	**596**	**731**	**635**	
OM&A	**554**	**566**	**582**	
PILs	66	40	31	
Total Debt	**2,748**	**3,248**	**3,415**	
Total Equity	2,168	2,280	2,426	

Assumptions

- No Distribution cost of service in 2012.
- Distribution IRM-ICM 2013/14, cost of service in 2015/16.
- ICM uses 2011 OEB Hydro One cost of capital
- 2013 ICM consists of $150M CIS and $211M Dx Capital; [redacted]

Results in US GAAP

Dx Summary of Key Changes

hydroOne

April Update:

- No 2012 cost of service
- CIS embedded in ICM in 2013/14

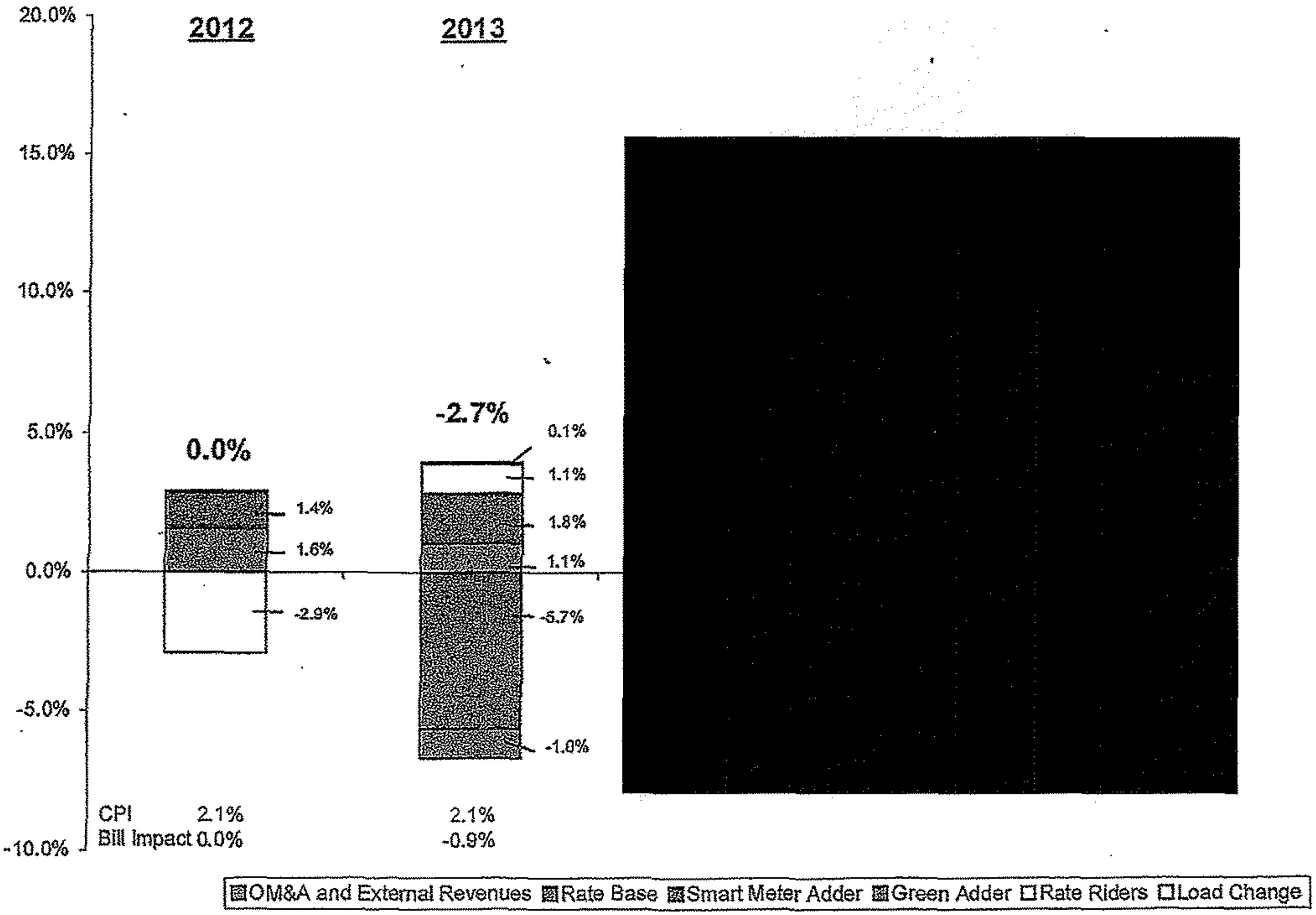
[redacted]

- ROE: 9.16% (2013), [redacted]
- SM adder stopping in 2015
- SG adder stopping in 2012; [redacted]
- 2011 Actuals updated
- Ontario budget freezes provincial income tax rates at 11.5%

November Board:

- 2012 cost of service
- CIS go-live 2012, accounting in-service 2013
- 2012 variance amounts refunded in 2013/14
- ROE: 9.70% (2013), [redacted]
- New (lower) depreciation rates effective 2012
- Load impact reflected in rates in 2012 (-2.9%)
- SM adder stopping in 2013
- 2011 SG adder continued through 2012; [redacted]
- 2011 Forecast
- Ontario provincial income tax rates declining to 10% in 2013

Dx Rate Increase: Nov Board

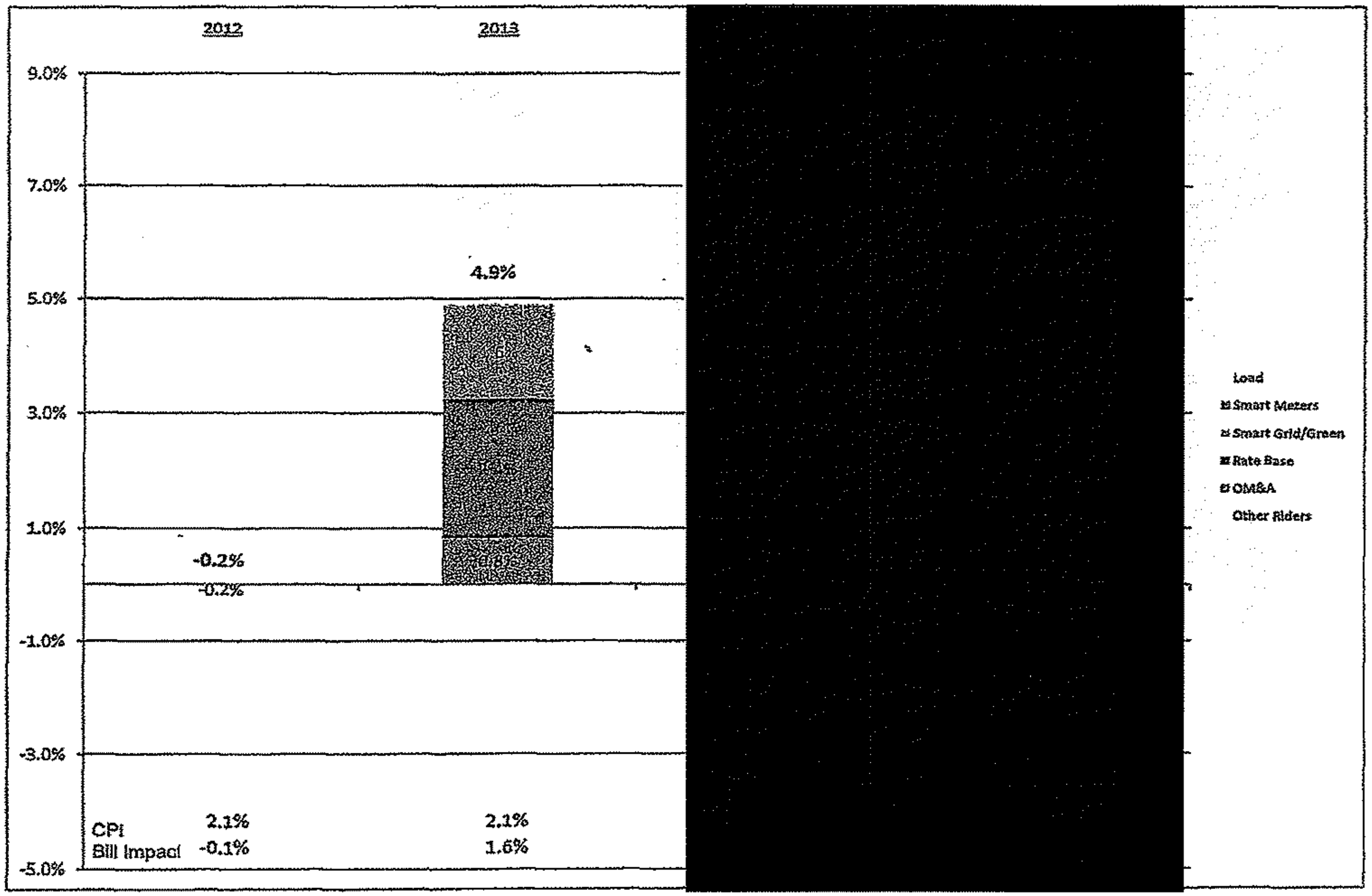


[redacted]

- Rate adders and riders causes changes to rates as collections or refunds begin and end
- Rate base component of rate change increases due mainly to in-servicing of capital projects

Dx Rate Increase: April Update Forecasted COC & Dep Threshold

hydroOne



[redacted]

- Forecasted cost of capital applied to ICM
- Depreciation materiality threshold

Energy Probe (EP) INTERROGATORY #2 List 1

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

Interrogatory

Ref. Exhibit A, Tab 13, Schedule 1, Appendix A – Business Plan Assumptions

Page 1 shows Ontario CPI forecasts are flat at 2%. Labour escalation forecasts on Pages 2 and 3 show forecasts for all categories of about 3% for the bridge and test years.

a) Why are HONI labour agreements higher than CPI forecasts?

b) Given the forecasts, will new labour agreements be pegged to 2% (plus COLA triggers)? If not, why not?

Response

a) Hydro One's wage escalation forecasts are higher than the CPI forecasts because it is not only the CPI that influences wages levels. Compensation for represented staff is determined through the collective bargaining process. There are many factors that affect the final settlement, including considerations such as history of the company, external settlements within the electricity sector, legislation, shareholder/government directives, financial performance, labour market considerations, bargaining unit expectations, recruitment, retention, employee engagement, demographics etc. Other factors to be considered are discussed throughout Exhibit C1, Tab 5, Schedule 2.

b) It is premature at this point to speculate on labour agreement negotiations that will be occurring in 2013.

Energy Probe (EP) INTERROGATORY #3 List 1

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

Interrogatory

Ref. Exhibit A, Tab 13, Schedule 1, Appendix A – Business Plan Assumptions

Section 5.0 of the appendix shows Incentive Plan forecasts.

a) Please provide details of the MCP plan.

b) Please summarize the agreement(s) that underpin the plan.

c) Show how the amount is calculated.

d) Please provide the annual costs 2013/2013.

e) Is there a similar plan for Senior Management/Executives in 2013/2014? If so please provide similar details?

Response

a) The Short Term Incentive Plan (STI) is designed to establish a strong correlation between corporate performance, individual performance and at-risk compensation. For management employees, the maximum allowable short term incentive is established for each salary band of management employees and is fixed as a percentage of base pay for that particular band.

The Hydro One Board of Directors annually determines the amount of the short term incentive based upon Hydro One's performance measured against a balanced scorecard.

With the STI amount established, managers assess individual performance and make an STI recommendation up to the maximum of the individual's allowable short term incentive. It is not an across the board allocation. Senior management reviews the recommendations and the final payout is approved by CEO.

b) Since the short term incentive is a totally at risk pay program, there are no agreements.

c) Please see response to part a)

d) The forecasted STI amounts for 2013 and 2014 are \$9.98M and \$10.28M respectively.

e) All regular MCP employees participate in the same short term incentive plan.

Energy Probe (EP) INTERROGATORY #4 List 1

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

Interrogatory

Ref. Exhibit A, Tab 13, Schedule 1, Appendix

Section 3 d) of the Appendix shows benefit costs rates forecasts. In the footnotes under ** reference is made to "retirement bonus".

a) What percentage of retiring employees receive the bonus?

b) Does the bonus apply to all employee groups?

c) How much does the average bonus amount to?

d) Does this bonus apply to Inergi employees? If so explain why.

Response

a) Approximately 84% of retiring staff received the retirement bonus

b) The retirement bonus applies to all regular PWU and Society represented employees as well as regular MCP employees hired prior to 2004. The retirement bonus does not apply to casual trades staff or to MCP staff employees hired after 2004.

c) In 2011, the average retirement bonus was approximately $8,300.

d) It is the decision of Inergi and its management whether they wish to pay such a bonus to their employees. Hydro One is in no way liable to Inergi for any payment or reimbursement of this or any other specific bonus.

Energy Probe (EP) INTERROGATORY #5 List 1

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

Interrogatory

Ref: Exhibit A, Tab 13, Schedule 1, Appendix A – Business Plan Assumptions

Section 5.0 of the Appendix shows benefit costs rates forecasts. In the footnotes under ** reference is made to OPRB (to INERGI where applicable). Please provide a copy or the key parts of the Inergi MSA that cover the services and costs to be incurred in the two test years.

Response

Details with respect to OPRB (Other Post Retirement Benefits) in the Inergi deal were included in the agreement signed in 2001; redacted copies of which were previously filed November 1, 2005, in Proceeding RP-2005-0020/EB-2005-0378, Exhibit H, Tab 1, Schedule 171.

The OPRB payments arise from employees that transferred to Inergi from Hydro One on March 1, 2002. Hydro One remains liable to reimburse Inergi for a portion of their OPRB costs proportionate to the percentage of their employment spent at Hydro One prior to transfer versus the time spent since at Inergi.

The payment is made to Inergi as a lump sum amount effectively coincident with the employees' actual retirement. When initiated in 2002, a liability was recorded and payments made to Inergi are logged against that liability going forward. Therefore, no expense is recorded upon payment.

Recent cash payments for this liability have been in the $0.6M/year range.

Energy Probe (EP) INTERROGATORY #6 List 1

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

Interrogatory

Refs. Exhibit A, Tab 13, Schedule 1, App A &
Exhibit A, Tab 15, Schedule 2, Pages 4-6 &
Exhibit A, Tab 15, Schedule 2, Appendix E

a) Explain the date(s) and sources of forecasts for CPI, Exchange rates and economic indicators (GDP and Housing Starts).

b) Confirm/explain whether the forecasts in the Business Plan and Load forecast are based on the same data (date and sources) and are consistent with those used for the Load Forecast.

c) Please provide the latest Consensus forecasts.

d) Please compare in Tabular form the economic assumptions for 2012-2014 –(CPI, GDP, Industrial Output, Commercial Floor Space) used by Hydro One Networks with the most recent projections made by the various 3rd party sources Hydro One Networks has relied upon.

Response

a) The Ontario CPI referenced in Exhibit A, Tab 13, Schedule 1, Appendix A was based on forecast prepared by IHS Global Insight released in April 2011. This forecast was part of 2012-2016 business planning assumptions issued in May 2011. The Ontario CPI in Exhibit A, Tab 15, Schedule 1 was based on forecast prepared by IHS Global Insight released in January 2012.

The 2012 exchange rate forecast, as provided in Exhibit A, Tab 15, Schedule 1, is based on the Consensus Forecasts prepared by Consensus Economics Inc. in September 2011. The 2013 and 2014 forecast is based on the forecast prepared by IHS Global Insight in June 2011.

The Ontario GDP and housing starts referenced in Exhibit A, Tab 15, Schedule 2, pages 4-6 and Appendix E are consensus forecasts prepared by Hydro One in January 2012 using the latest forecast of Ontario GDP and housing starts available from 13 economic establishments. Names of 13 establishments and their forecast release dates are provided in Exhibit A, Tab 15, Schedule 2, Appendix E.

b) Yes, the Ontario CPI in the Business Plan and the economic data used in the Load Forecast are based on different forecast dates because the load forecast was prepared in February 2012 using the latest available information. Please see the response to a) for dates and sources.

c) The latest consensus forecast prepared in August 2012 is provided below:

Survey of Ontario GDP Forecast (annual growth rate in %)

	2012	2013	2014
Global Insight (June 2012)	1.8	2.2	2.3
Conference Board (July 2012)	2.1	2.3	2.9
U of T (July 2012)	2.1	2.1	2.9
C4SE (June 2012)	2.1	2.3	1.8
CIBC (June 2012)	2.1	2.0	
BMO (August 2012)	2.0	1.9	
RBC (June 2012)	2.5	2.4	
Scotia (August 2012)	1.8	1.7	
TD (July 2012)	2.1	1.9	
Desjardins (June 2012)	1.8	2.1	
Central 1 (Feb 2012)	2.3	2.8	2.2
National Bank (Summer 2012)	1.8	1.7	
Laurentian Bank (July 2012)	1.8	1.8	
Average	**2.0**	**2.1**	**2.4**

Survey of Ontario Housing Starts Forecast (in 000's)

	2012	2013	2014
Global Insight (June 2012)	67.4	60.7	65.7
Conference Board (July 2012)	78.2	71.7	77.2
U of T (July 2012)	77.5	67.4	66.8
C4SE (June 2012)	66.6	65.0	62.0
CIBC WM (March 2012)	67.0	63.5	
BMO (August 2012)	73.6	63.5	
RBC (June 2012)	74.8	68.5	
Scotia (August 2012)	78.0	66.0	
TD (July 2012)	78.0	63.4	
Desjardins (June 2012)	74.4	60.8	
Central 1 (Nov 2011)	67.3	71.5	72.2
National Bank (Summer 2012)	75.0	62.0	
Laurentian Bank (July 2012)	76.5	62.0	
Average	**73.4**	**65.1**	**68.8**

Updated August 27, 2012

d) The requested information is provided in the following table.

	EB-2012-0031 Forecast			**Updated Forecast**			
	2012	**2013**	**2014**	**2012**	**2013**	**2014**	**Data Source**
Ontario GDP	1.8	2.4	2.7	2.0	2.1	2.4	Consensus Forecast prepared by Hydro One in August 2012
Ontario CPI	2.0	2.1	2.0	2.0	2.2	1.9	Global Insight prepared in June 2012
Industrial output	6.0	4.2	4.6	1.6	4.1	4.1	Global Insight prepared in July 2012
Commercial Floor Space	0.6	1.0	1.3	No update available			Hydro One

Energy Probe (EP) INTERROGATORY #7 List 1

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

Interrogatory

Ref. Exhibit A, Tab 2, Schedule 1

a) Please provide a schedule that shows the proposed bill impacts for 2013 and 2014.

b) Please provide a schedule that shows the impact on a typical residential LDC customer consuming 500 and 1000 kWh/month.

Response

a) Please refer to Interrogatory Response filed at Exhibit I, Tab 2, Schedule 1.04 Staff 5.

b) The impact on a typical residential R1 customer consuming 500 kWh and 1000 kWh is determined based on the increase in the customer's Retail Transmission Service charges as detailed below.

Input Data:

Data		Reference
Retail Transmission Service Rates (RTSR) for R1 Customers as of January 2012		
Tx Network = 0.585 ¢/kWh		Distribution Rate Order in EB-2009-0096 issued December 21, 2010
Tx Line & Transformation = 0.464 ¢/kWh		Distribution Rate Order in EB-2009-0096 issued December 21, 2010
2013 Transmission Rates Impact = 0.6 %	(A)	Exhibit A, Tab 2, Schedule 1
2014 Transmission Rates Impact = 9.1%	(B)	Exhibit A, Tab 2, Schedule 1
Hydro One Transmission Share of Uniform Transmission Charges = 0.96772	(C)	Exhibit H2, Tab 1, Schedule 1, Attachment 2

Calculation of impacts:

		Consumption Level		
	Calculation	800 kWh (per Notice)	500 kWh	1000 kWh
RTSR included in 2012 R1 Customer's Bill *(kWh x 1.085 loss factor x RTSR Rates)*	D	$9.11	$5.69	$11.38
Retail Transmission Service Charges in 2013	E = D x (1 + AxC)	$9.16	$5.72	$11.45
2013 increase in R1 Customer's Monthly Bill	(E - D)	**$0.05**	**$0.03**	**$0.07**
Retail Transmission Service Charges in 2014	F = E x (1 + BxC)	$9.96	$6.23	$12.46
2014 increase in R1 Customer's Monthly Bill	(F - E)	**$0.81**	**$0.50**	**$1.01**

Vunerable Energy Consumer Coalition (VECC) INTERROGATORY #1 List 1

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

Interrogatory

Reference: Exhibit A, Tab 3, Schedule 1, pages 8-9

Please provide a table which breaks down and identifies and quantifies the increase in revenue requirement by component for 2013 over 2012 and for 2014 over 2013.

Response

Table 3, in Exhibit E1, Tab 1, Schedule 1 breaks down the components of the change to revenue requirement from 2012 to 2013. Table 5 of the same Exhibit, provides an explanation of the change from 2013 to 2014. Please also refer to the response to Exhibit I, Tab 02, Schedule 1.14 Staff 15.

Vunerable Energy Consumer Coalition (VECC) INTERROGATORY #2 List 1

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

Interrogatory

Reference: Exhibit A, Tab 4, Schedule 1, page 11

a) Does Hydro One expect that the East-West Tie partnership will result in a completed project that costs less than it would if Hydro One undertook this project on its own?

b) Does Hydro One contemplate any other competitive transmission projects that it will be undertaking in the next five years?

Response

a) Hydro One Networks is not participating in the OEB's designation process to construct the East-West tie and has not prepared any detailed cost estimates for the project.

Although some Hydro One Networks staff were involved in the EWT partnership, they were withdrawn from EWT, effective July 27 2012, to comply with the OEB's July 12 Decision and Order. EWT had not undertaken any project development activity, that is required to estimate project costs, during the period that Hydro One Networks staff were included in the partnership.

Thus, Hydro One does not have the information to respond to the question.

b) At this time, Hydro One is not aware of any other competitive transmission projects that will be occurring in the next five years.

Vunerable Energy Consumer Coalition (VECC) INTERROGATORY #3 List 1

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

Interrogatory

Reference: Exhibit A-8-3, Appendix A, page 8, Schedule "A"

a) Please provide a copy of Schedule "A" that was in effect prior to the cited document (i.e., the Schedule "A" in effect prior to January 17, 2012.)

b) Does Hydro One expect the same Schedule "A" will be in effect for 2013 and 2014? If not, please explain.

Response

a) Please see below for Schedule A of the agreement dated January, 2011.

Schedule "A"

The annual cost for the performance of the Services to be delivered is summarized as follows:

Services	SERVICES TO BE PROVIDED BY HYDRO ONE INC. TO: (in $Thousands)			
	Hydro One Networks Inc.	Hydro One Remote Communities Inc.	Hydro One Telecom Inc.	Hydro One Brampton Networks Inc.
General Counsel & Secretary (including Corporate Executive Office)	914.0	24.4	9.8	19.6
President / CEO / Chairman Services	3,378.1	17.4	29.8	35.7
Chief Financial Office Services (including Strategic Financial services)	801.7	7.0	28.1	37.3
Totals	**5,093.8**	**48.8**	**67.7**	**92.6**

DESCRIPTION OF SERVICES:

General Counsel and Secretary

The Services Provider shall provide the Services Recipient with professional legal advice and input. This advice shall include, but shall not be limited to, interpretation and analysis of legislation and regulations, advice concerning corporate structure and governance, development of regulatory instruments (licences), contracts, and environmental and health and safety issues. The Services Provider will also provide guidance on business ethics and support in the form of a business code of conduct.

President / CEO / Chairman services

The Services Provider shall provide the Services Recipient with strategic direction and management in an attempt to ensure that the Services Recipient's corporate goals are achieved.

Chief Financial Office services (including Strategic Financial services)

The Services Provider shall provide the Services Recipient with strategic direction and management in an attempt to ensure that the Services Recipient's corporate financial goals are achieved.

The Services Provider shall provide the Services Recipient with strategic approval with respect to investment decisions. Services relating to the review of policies and procedures, treasury operations and tax planning, financial control and reporting will also be provided by the Services Provider to the Services Recipient as required by the Services Recipient.

b) No. A new agreement will be negotiated with costs similar to those shown on Exhibit A, Tab 8, Schedule 3, page 8 for 2013 and 2014.

Vunerable Energy Consumer Coalition (VECC) INTERROGATORY #4 List 1

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

Interrogatory

Reference: Exhibit A-8-3, Appendix B, page 8, Schedule "A"

a) Please provide a copy of the Schedule "A" that was in effect prior to the cited document (i.e., the Schedule "A" in effect prior to January 17, 2012.)

b) Does Hydro One expect the same Schedule "A" will be in effect for 2013 and 2014? If not, please explain.

Response

a) Please see below for Schedule A of the agreement dated January, 2011.

Schedule "A"

The annual cost for the performance of the Services to be delivered is summarized as follows:

	SERVICES TO BE PROVIDED BY HYDRO ONE NETWORKS INC. TO: (in $Thousands)			
SERVICES	**Hydro One Inc.**	**Hydro One Remote Communities Inc.**	**Hydro One Telecom Inc.**	**Hydro One Brampton Networks Inc.**
General Counsel and Secretary Services	87.0	292.5	87.0	174.0
Financial Services	44.5	346.0	300.1	362.3
Corporate Services	2.4	179.7	260.2	37.7
Telecommunication Services	-	134.2	255.3	-
Other Services	-	464.3	1,605.7	-
Totals	**133.9**	**1,416.7**	**2,508.3**	**574.0**

DESCRIPTION OF SERVICES:

The following provides a generic description of all Services to be provided by the Services Provider.

GENERAL COUNSEL AND SECRETARY SERVICES

The Services Provider shall provide the Services Recipient with professional legal advice and input which shall include, but not be limited to, interpretation and analysis of legislation and regulations, advice concerning corporate structure and governance, development of regulatory instruments (licenses), contracts, and environmental and health and safety issues.

FINANCIAL SERVICES

The Services Provider shall provide financial services support to the Services Recipient by providing timely and reliable financial information. The Services Provider will also provide services relating to business planning, budgeting and financial reporting. As required, services relating to treasury/pension/investor relations, taxation, internal audit and risk management, insurance, financial systems and services, cost and inventory accounting and decision support will also be provided. Other financial services such as transaction processing (accounts payable and receivable), and fixed asset and general accounting will also be provided.

CORPORATE SERVICES

The Services Provider shall provide corporate services in five main areas:

- Human Resources / Labour Relations – provision of human resource policy, strategy and standards to meet legal and other requirements. This includes staff planning, leadership development, succession planning and change management as well as labour relations services, pay equity, diversity, health services and performance management, compensation, health and benefits programs and administration of payroll, benefit plans and incentive plans.
- Business Architecture – provision of information systems support for Cornerstone Phase 1 and 2 as well as the management of legacy tools to support real time operations.
- Information Management – provision of computer and applications management support, internal telecommunications management, IT capital projects and IT strategy management and Inergi applications support management.
- Corporate Security – provision of advice, guidance and investigative support services to ensure the protection of assets and optimize the reliable delivery of electricity.
- First Nations & Métis Relations – provision of leadership and consultation support to address issues with First Nations & Métis communities.
- Corporate Communications – provision of strategy, program and support for corporate communications, public affairs and media relations, as well as corporate and shareholder relations and strategy programs related to internal communications.

TELECOMMUNICATIONS SERVICES

The Services Provider shall provide the Services Recipient with various telecommunications-related services including field and engineering, logistics, corporate, construction, telecommunication and information technology services.

OTHER SERVICES

The Services Provider shall provide the Services Recipient with:

- Customer Services Operation – provision of bill production and dispatch and settlements service, as well as data services related to field-based service orders.
- Information Management – provision of infrastructure operations, including a variety of activities such as system testing and integration, Internet and database management services, as well as services related to mainframe infrastructure operations, end user and desk-top support.

b) No. A new agreement will be negotiated with costs similar to those shown on Exhibit A, Tab 8, Schedule 3, page 8 for 2013 and 2014.

Vunerable Energy Consumer Coalition (VECC) INTERROGATORY #5 List 1

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

Interrogatory

Reference: Exhibit A-1 0-2, Attachment 1, page 4, Management Discussion and Analysis, Quarterly Results of Operations Table

a) Please confirm that the total revenue for the quarter ending March 31, 2012 was the highest since 2010.

b) Please update this table to reflect second quarter 2012 results.

Response

a) Transmission revenue for the quarter ending March 31, 2012 was the second highest quarterly result since December 31, 2010. Revenues for Q3 2011 were the highest for the January 1, 2011 to June 30, 2012 period at $379 million.

b) The updated information can be found at Exhibit A, Tab 10, Schedule 2, Attachment 2, filed August 15, 2012.

Vunerable Energy Consumer Coalition (VECC) INTERROGATORY #6 List 1

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

Interrogatory

Reference: Exhibit A, Tab 12, Schedule 1, page 7, Definition of Bulk Electric System

a) Are there any impacts of the proposed change to BES included in this application?

Response

There are no dollar impacts of the proposed BES definition included in this application.

Vunerable Energy Consumer Coalition (VECC) INTERROGATORY #7 List 1

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

Interrogatory

Reference: Exhibit A-13-1, Appendix A, page 3, Provincial Income Tax Rate

a) Is it possible that the provincial tax rate of 11.25% will remain in effect for 2013 and beyond? If so, please provide the impact on the 2013 and 2014 revenue requirements.

Response

The updated Exhibit C1, Tab 9, Schedule 1, page 6 Payments in Lieu of Income Tax Rates, indicates that for the 2013 and 2014 test years the 11.5% enacted provincial tax rate is applicable. The 2013 and 2014 revenue requirements filed August 15, 2012, reflect this rate.

Vunerable Energy Consumer Coalition (VECC) INTERROGATORY #8 List 1

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

Interrogatory

Reference: Exhibit A, Tab 15, Schedule 1, pages 1-2, Transmission Cost Escalation

a) Please provide any additional information that is readily available regarding Transmission Cost Escalation for Construction, Operations and Maintenance in respect of (i) how accurate the forecasts have been compared with historical actuals, (ii) how widespread is the use of these forecasted escalators within the utility sector, (iii) the weighting and the data sources underlying the escalators and whether there has been any change in either of these in recent years, (iv) whether separate escalators are calculated for the US and Canada, and (v) the extent to which the escalators and actuals tracked the CPI historically.

b) If possible please extend Table 1 to include all historical years for which data is available, showing the forecasted escalator and Hydro One's actual historical actual transmission cost escalators for each year.

Response

a) (i) Please refer to the response in part b) below.

(ii) The IHS Global Insight Power Planner Report has been in place since 1980. According to IHS Global Insight, the Power Planner Report has been widely used in rate proceedings by numerous utilities and public utility commissions in North America.

(iii) The historical data, weighting factors, and specifications for the Transmission Cost Escalation for Construction model come from the Handy Whitman Index of Public Utility Construction Costs as published by Whitman, Requardt & Associates, LLP. The Operation and Maintenance model is developed by IHS Global Insight using weighting factors and specifications based on the Electric and Gas Uniform System of Accounts and Form 1 Electric Utility Annual Report Data as published by the Federal Energy Regulatory Commission and Department of Energy. Both models are based on information from the mid-1990s and this has not changed in recent years. The specific weighting factors are considered proprietary by IHS Global Insight and are not available to Hydro One.

(iv) Separate escalators for the US and Canada are not calculated.

(v) The relationship between historical Ontario CPI and the historical Transmission Cost Escalators for Construction and Operations & Maintenance are shown in the table below. The escalators for Operations & Maintenance are actual historical values expect for 2011 which is the forecasted value from the latest IHS Global Insight Power Planner Report (August 2012). Actual values for the Construction escalator are not made available by IHS Global Insight, so the last available forecasted value is provided for each year (usually from the fourth quarter of the following year). The Ontario CPI numbers are actual historical values from Global Insight.

Year	Transmission Cost Escalator for Construction (%)	Transmission Cost Escalator for Operations & Maintenance (%)	Ontario CPI (% Change)
2002	2.2	0.8	2.0
2003	1.5	1.3	2.7
2004	7.6	3.8	1.9
2005	8.1	5.6	2.2
2006	8.6	4.4	1.8
2007	8.1	3.6	1.8
2008	9.3	6.6	2.3
2009	-2.6	-0.1	0.4
2010	1.9	1.5	2.4
2011	3.7	3.6	3.1

b) The table below presents the forecast accuracy for the Board-accepted forecasts of the Transmission Cost Escalators for Construction and Operations and Maintenance from Hydro One's past three rate applications (EB-2006-0501, EB-2008-0272, and EB-2010-0002). The forecasted values used in each application are highlighted gray. Each forecast is compared to the actual values, where available, or best available forecasted values from Global Insight. The escalators for Operations & Maintenance are actual historical values except for 2011 and 2012 which are the forecasted values from the latest IHS Global Insight Power Planner Report (August 2012). Actual values for the Construction escalator are not made available by IHS Global Insight, so the last available forecasted value is provided for each year (usually from the fourth quarter of the following year).

Year	Transmission Cost Escalator for Construction (%)				Transmission Cost Escalator for Operations & Maintenance (%)			
	EB-2006-0501 (1)	EB-2008-0272 (2)	EB-2010-0002 (3)	Historical Values from IHS Global Insight (4)	EB-2006-0501 (1)	EB-2008-0272 (2)	EB-2010-0002 (3)	Historical Values from IHS Global Insight (4)
2003	1.5			1.5	2.9			1.3
2004	7.6			7.6	3.6			3.8
2005	7.7	8.1		8.1	6.0	5.5		5.6
2006	3.8	8.6		8.6	2.3	4.3		4.4
2007	1.7	6.7	8.1	8.1	1.8	3.2	3.8	3.6
2008	2.3	2.3	8.4	9.3	1.6	2.7	6.3	6.6
2009		1.0	2.6	-2.6		1.4	3.6	-0.1
2010		1.8	1.0	1.9		0.7	1.4	1.5
2011			0.4	3.7			1.3	3.6
2012			1.2	2.3			1.6	2.3

(1) EB-2006-0501; Exhibit A; Tab 14; Schedule 2; Page 2

(2) EB-2008-0272; Exhibit A; Tab 14; Schedule 2; Page 2

(3) EB-2010-0002; Exhibit A; Tab 12; Schedule 2; Page 2

(4) IHS Global Insight publishes actual historical values for the Operations & Maintenance values only. The Construction values from Global Insight are the last available forecasted value for each year (usually from the fourth quarter of the following year). The 2011 and 2012 Global Insight values for both Construction and O&M are the latest estimates from the August 2012 IHS Global Insight Power Planner Report.

Vunerable Energy Consumer Coalition (VECC) INTERROGATORY #9 List 1

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

Interrogatory

Reference: Exhibit A, Tab 15, Schedule 1, page 3

a) Does the fact that the exchange rate has no impact on forecasted costs reflect the fact that Hydro One buys no equipment, tools, or inventory priced in US dollars?

Response

In line 16 of page 3 in Exhibit A, Tab 15, Schedule 1, Hydro One stated that exchange rate forecast is not directly used to forecast costs or other variables. Exchange rate has very small impact on forecasted costs because Hydro One attempts to secure US Dollar contracts in the Canadian equivalent at the time the contract is negotiated, thereby transferring all currency fluctuation risk to the vendor.

Vunerable Energy Consumer Coalition (VECC) INTERROGATORY #10 List 1

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

Interrogatory

Reference: Exhibit A, Tab 16, Schedule 1, pages 3 and 4 and Exhibit A, Tab 10, Schedule 1, 2010 Annual Report page 9

a) Please explain when and why the Lost Time Injury measure was replaced by the Medical Attention measure.

b) Could Hydro One track both the Lost Time Injury measure and the Medical Attention measure?

c) On page 9 of the 2010 Annual report it states that "the Journey to Zero program was launched in 2009 .... In 2010, we had a frequency of 2.8 medical attentions and 0.051ost-time injuries per 200,000 hours worked. This exceeded our target of 3.6 medical attentions and 0.231ost-time injuries per 200,000 hours worked." Please provide your actuals and targets for both of these metrics and Hydro One's targets for both metrics for the years 2012, 2013, and 2014.

d) When will the CEA average for 2011 Lost Time Injuries be known? If available now, please provide this number.

e) Please explain why the CEA average is a good comparator for Hydro One performance with respect to these safety metrics.

Response

a) Hydro One's focus on medical attention injuries began in 2010. The medical attention (MA) metric is closely aligned with the recordable injury frequency rate used by the Canadian Electricity Association and the US Occupational Safety & Health Administration. Lost time injuries are counted in the MA metric (they are a subset of MA injuries). The MA metric is therefore a broader measure of performance and better allows identification of opportunities to identify injury situations and their prevention/avoidance as part of our progress to achieving world-class standing for medical attentions.

b) Hydro One tracks Lost Time Injuries as a category within the Medical Attention measure.

c) The 2010 actuals and targets for these metrics were reported in the annual report as quoted above. Hydro One's focus is currently on the medical attention metric for which Hydro One Networks established a target for 2011 of 2.2 medical attention injuries per 200,000 hours worked. Hydro One's actual performance in 2011 was 3.7. No target was set for lost time injuries since these are part of the medical attention metric. For 2012, the target for medical attention frequency is 2.2. Hydro one has not yet set the targets for 2013 and 2014.

d) The CEA average number for lost time injuries in 2011 was: 0.74 per 200,000 hours worked.

e) The Canadian Electricity Association average is a good comparator because it allows Hydro One to compare its performance against other Canadian electrical utilities operating in the power industry sector.

Vunerable Energy Consumer Coalition (VECC) INTERROGATORY #11 List 1

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

Interrogatory

Reference: Exhibit A, Tab 16, Schedule 1, page 5 and Figure 2

a) When will the CEA average for 2011 Recordable Injury Frequency be known? If available now, please provide this number.

b) Please explain why the CEA average is a good comparator for Hydro One performance with respect to the Recordable Injury Frequency metric.

c) The 2011 Recordable Injury Frequency 2011 metric for Hydro One appears to be about three times the target of 1.2 recordable injuries per 200,000 hours worked. When does Hydro One expect to meet this target?

Response

a) The CEA average for Recordable Injury Frequency in 2011 was 2.2 recordable injuries per 200,000 hours worked.

b) See response to Exhibit I, Tab 2, Schedule 5.10 VECC 10, part e).

c) For 2011 (and 2012), Hydro One's target for medical attention injuries was: 2.2 injuries per 200,000 hours worked. This metric is equivalent to the recordable injury frequency metric. Hydro One's vision is to achieve world-class standing for recordable injuries and we have determined world-class performance to be 1.2 recordable injuries per 200,000 hours worked. It is not unusual for there to be some variability in performance as you move ahead with continuous improvement initiatives. As part of our Journey to Zero initiative and our Health & Safety Management System, we are implementing programs to reduce medical attention injuries in the major category areas such as motor vehicle accidents, exertions and electrical contacts, but results of such programs are expected to contribute to improved performance over the next few years (not instantaneous). Adjustments in the programs will be made to ensure continuous improvement in our performance. Hydro One's strategic objective is to meet world class standing in five years.

Vunerable Energy Consumer Coalition (VECC) INTERROGATORY #12 List 1

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

Interrogatory

Reference: Exhibit A, Tab 16, Schedule 1, page 6 and Figure 3, Transmission Customer Satisfaction survey results

a) The customer satisfaction survey results for major load customers have shown steadily declining satisfaction levels from 2007-2011. Can Hydro One confirm that the survey questions have not changed materially over this period?

b) Please provide a copy of the most recent survey questions sent to major load customers and to generator customers.

Response

a) The customer satisfaction survey question wording remained stable from 2007 to 2011.

b) Please refer to Exhibit I, Tab 12, Schedule 9.06 SEC 30, Attachments 1 and 2.

Vunerable Energy Consumer Coalition (VECC) INTERROGATORY #13 List 1

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

Interrogatory

Reference: Exhibit A, Tab 16, Schedule 1, pages 12-18, Figures 4-10

a) Please update Figures 4-10 with the 2011 CEA composite data if available.

Response

See Exhibit I, Tab 16, Schedule 1.01 Staff 73.

Vunerable Energy Consumer Coalition (VECC) INTERROGATORY #14 List 1

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

Interrogatory

Reference: Exhibit A, Tab 17, Schedule 1, pages 7 and 8

a) With respect to specific efficiency initiatives, Hydro One states that *"Aggregate incremental savings achieved in the 2009 to 2011 period are ahead of internal projections."* (Page 8, lines 12-13). Please provide Hydro One's internal projections for the 2009-2011 period and also for the 2012-2014 period.

Response

Original internal projections for incremental savings 2009-2011:

	2009	2010	2011
OM&A (non-Cornerstone) Savings ($M)	1.9	2.8	2.0
Capital (non-Cornerstone) Savings ($M)	3.0	4.3	3.3
Cornerstone OM&A Savings ($M)	6.0	4.0	3.2
Cornerstone Capital Savings ($M)	5.0	3.0	2.0

For the 2012-14 period the internal projections are as filed in Exhibit A, Tab 17, Schedule 1, page 7.

Power Workers Union (PWU) INTERROGATORY #1 List 1

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

Interrogatory

Ref (1): Exhibit A/Tab 13/Sch 1/Appendix A/Page 1/Lines 6-8 (2012 Business Plan Assumptions-Economics)

	2012	2013	2014	2015	2016
CPI – Ontario (%)	2.1	2.1	2.0	2.0	2.0
Tx cost escalation for Construction (%)	3.8	2.7	2.2	3.0	2.6
Tx cost escalation for Operations & Maintenance (%)	2.7	2.5	2.1	2.9	1.9

Ref (2): Exhibit A/Tab 15/Sch 1/Page 2/Table 1

Table 1

	Historic			Bridge	Test	
	2009	2010	2011	2012	2013	2014
Transmission Cost Escalation for Construction (%)	-2.6	1.9	4.4	4.3	2.0	2.0
Transmission Cost Escalation for Operations & Maintenance (%)	-0.1	1.6	3.7	1.9	2.4	2.8

a) In Ref (1), Hydro One indicates that CPI-Ontario forecasts were based on the HIS Global Insight April 2011 forecast. Please confirm if the data for the other two items (Transmission cost escalation for construction & Transmission cost escalation for OM) are also based on the IHS Global Insight April 2011 forecast.
b) Hydro One indicates that the data in Table 1 in Ref (2) was provided by Global Insight's February 2012 forecast. It appears that there is a discrepancy between the data in the Table in Ref (1) and the data in the Table in Ref (2) in particular with reference to the Transmission cost escalation forecasts. Please reconcile the two sets of data.
c) Please provide explanation for the assumptions behind the sharp decrease in Transmission cost escalation forecast for Operations & Maintenance from 2.9% in 2015 to 1.9% in 2016 in the table in Ref (1).
d) Please provide the labour escalation forecasts that are used to derive the Transmission cost escalation forecasts for both construction and for Operations & Maintenance.

Response

a) Yes, the Transmission Cost Escalation for Construction & Transmission Cost Escalation for Operations & Maintenance are from the April 2011 edition of IHS Global Insight Power Planner Report.

b) The numbers in both tables are confirmed to be correct. The table in Ref (1) was compiled in May 2011 while Table 1, Ref (2), was compiled in February 2012. The latest forecast available from IHS Global Insight was used at the time each table was compiled. Hydro One assumes that the differences are attributable to changing economic conditions and the subsequent impact on commodity prices (particularly on metal prices).

c) According to IHS Global Insight, the models to forecast the Cost Escalation for Operations & Maintenance reflect a number of factors that coincide with the stages of a business cycle. The forecasts show a ramp up in cost escalation in 2015, which is the height of the business cycle, and then ease out in 2016. This is consistent with macroeconomic assumptions in which pent up pressures in the global recovery years are finally released in coordination with the interest rate outlook.

d) The labour escalation forecast for the Construction Cost Escalation model is from IHS Global Insight's February 2012 Power Planner. It is the proprietary property of IHS Global Insight and therefore cannot be provided.

School Energy Coalition (SEC) INTERROGATORY #1 List 1

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

Interrogatory

Please provide all presentations to executive management and the Board of Directors supporting approval of the following documents:

a. The current Application and associated budgets
b. Transmission 10 Year Outlook

Response

a. Please refer to the response to Exhibit I, Tab 2, Schedule 3.01 EP 1.

b. No presentation material was provided to Hydro One's executive management at their meeting held on May 14, 2012 for the discussion of the 10-Year Transmission Asset Management Outlook ("Outlook"). This Outlook was not submitted to Hydro One's Board of Directors.

School Energy Coalition (SEC) INTERROGATORY #2 List 1

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

Interrogatory

Please provide a copy of all directions from the shareholder since January 1, 2010 that are not already in the evidence.

Response

Please refer to Attachment 1 of this Exhibit.

HYDRO ONE INC.

RESOLUTION OF THE SOLE SHAREHOLDER

REGARDING COST ALLOCATION AND COST RECOVERY FOR TRANSMISSION SYSTEM UPGRADES

WHEREAS Her Majesty the Queen in Right of the Province of Ontario as Represented by the Minister of Energy (the "**Shareholder**"), as the registered holder of all the issued shares of Hydro One Inc. (the "**Corporation**"), executed a unanimous shareholder agreement (the "**Shareholder Agreement**") dated as of April 19th, 2011 regarding the Corporation;

AND WHEREAS paragraph 1 of the Shareholder Agreement removed from the Directors of the Corporation all of their rights, powers and duties in relation to decisions by Hydro One Networks Inc. ("**HONI**"), the Corporation's wholly-owned subsidiary, related to:

(i) the pursuit of cost recovery, by HONI, from microFIT and small-scale (capacity allocation exempt) FIT generation projects or proponents thereof for costs related to investment and expenditures made, or required to be made, by HONI, in order to appropriately fund the upgrades at up to fifteen (15) transmission stations pursuant to the February 28, 2011 licence condition amendments made to HONI's transmission licence;

(ii) the pursuit of cost recovery, by HONI, of such costs through regulatory processes designed to ultimately recover costs from Ontario electricity consumers through electricity rates;

(iii) whether or not to pursue and implement, and require HONI to pursue and implement, internal cost recovery or cost mitigation measures designed to off-set the costs associated with the upgrades, and to pursue further cost minimization strategies and to increase overall cost efficiencies within HONI and the Corporation, including the timing of any such decisions.

AND WHEREAS the Shareholder wishes to ensure that the Corporation is managing its business and affairs in compliance with the Government of Ontario's policies in relation to alternative methods of managing costs including maximizing internal efficiencies, while maintaining the safety and reliability of the electricity system;

AND WHEREAS the Shareholder wishes to exercise its rights and powers under paragraph 1 of said Shareholder Agreement in relation to the management of the costs identified therein.

NOW THEREFORE BE IT RESOLVED AS A RESOLUTION OF THE SOLE SHAREHOLDER OF THE CORPORATION THAT:

1. The Corporation shall not, unless notified otherwise, seek or permit HONI to seek cost recovery for the upgrades from either microFIT or small-scale FIT generators, whether directly or indirectly, for costs related to investment and expenditures made, or required to be made, by HONI in order to appropriately fund the upgrades at up to fifteen (15) transmission stations pursuant to the February 28, 2011 licence condition amendments made to HONI's transmission licence.

2. The Corporation shall not, unless notified otherwise, seek or permit HONI to seek cost recovery for the upgrades through regulatory processes designed to ultimately recover costs from Ontario electricity consumers through electricity rates.

3. The Directors shall make all reasonable efforts and take all reasonable steps as soon as is practical to achieve cost reductions and maximize cost efficiencies within the Corporation, which are equivalent to amounts which are not recoverable from generators or electricity customers through electricity rates, as outlined in paragraphs 1 and 2 above.

4. The Directors shall ensure that this resolution is carried out in accordance with all applicable laws, and in accordance with sound commercial practice for a corporation involved in the transmission and distribution of electricity and in accordance with all applicable licences and with the Independent Electricity System Operator's Market Rules.

5. Any officer or Director of the Corporation be and is hereby authorized and directed to execute and deliver all documents and agreements, and to do and perform all things as may be necessary or desirable, in order to give effect to and implement the foregoing resolutions.

The foregoing resolutions are hereby consented to as evidenced by the signature of the sole shareholder of the Corporation pursuant to the provisions of the *Business Corporations Act* (Ontario).

DATED as of the 19th day of April, 2011.

Her Majesty the Queen in Right of the Province of Ontario, as represented by the Minister of Energy

HYDRO ONE INC.

DECLARATION OF THE SOLE SHAREHOLDER REGARDING the allocation of costs and cost recovery for certain transmission system expansion, reinforcement and upgrade activities (the **"upgrades"**), such declaration being made as of the 19th day of April, 2011 (the "**Effective Date**");

WHEREAS HER MAJESTY THE QUEEN IN RIGHT OF THE PROVINCE OF ONTARIO AS REPRESENTED BY THE MINISTER OF ENERGY (the **"Shareholder"**) is the registered and beneficial owner of all the issued and outstanding shares of Hydro One Inc (the "**Corporation**");

AND WHEREAS the Shareholder recognizes that the Corporation is itself the sole shareholder of Hydro One Networks Inc. ("**HONI**") which is licensed by the Ontario Energy Board as both a transmitter and a distributor;

AND WHEREAS the upgrades are an important element of the government's Long Term Energy Plan, and are necessary to help ensure the electricity grid is able to accommodate Ontarians' tremendous response to the microFIT program and capacity allocation exempt (CAE) applications to the FIT program;

AND WHEREAS HONI's transmission licence requires the company to develop and implement transmission projects to increase short circuit and/or transformer capacity at up to fifteen (15) of the Licensee's transmission stations during the forty-eight (48) month period beginning March 1, 2011, to enable the connection of small-scale renewable energy generation facilities;

AND WHEREAS HONI's business decisions must include consideration of the impact of those decisions on electricity ratepayers, as well as the safety and reliability of the electricity system;

AND WHEREAS the Shareholder finds it necessary to assume decision-making power and authority over certain distinct aspects of the business operations of the Corporation, and in particular, in regards to certain decision-making authority that the Corporation has with respect to its own wholly-owned subsidiary, HONI, such decisions having implications for small-scale FIT and microFIT generators;

AND WHEREAS the Shareholder makes the following declaration pursuant to subsection 108(3) of the *Business Corporations Act* (Ontario) (the "**Act**") intending the same to be deemed to be a Unanimous Shareholder Agreement within the meaning of the Act.

NOW THEREFORE it is hereby declared that:

1. The rights, powers and duties of the Directors (the "**Directors**") of the Corporation to manage, or supervise the management of, the business

and affairs of the Corporation, whether such rights, powers or duties arise under the Act, the articles of incorporation of the Corporation or the by-laws of the Corporation, as and when amended, or otherwise, are forthwith restricted with regard to any decisions regarding:

(i) the pursuit of cost recovery, by HONI, from microFIT and small-scale (capacity allocation exempt) FIT generation projects or proponents thereof for costs related to investment and expenditures made, or required to be made, by HONI, in order to appropriately fund the upgrades at up to fifteen (15) transmission stations pursuant to the February 28, 2011 licence condition amendments made to HONI's transmission licence;

(ii) the pursuit of cost recovery, by HONI, of such costs through regulatory processes designed to ultimately recover costs from Ontario electricity consumers through electricity rates;

(iii) whether or not to pursue and implement, and require HONI to pursue and implement, internal cost recovery or cost mitigation measures designed to off-set the costs associated with the upgrades, and to pursue further cost minimization strategies and to increase overall cost efficiencies within HONI and the Corporation, including the timing of any such decisions.

2. Those rights, powers and duties of the Directors are hereby assumed by the Shareholder and no longer reside with the Board of Directors or any members thereof, from the Effective Date, until this Declaration is amended or revoked. (collectively, the "**Restricted Powers**").

3. This Declaration and the restriction of the powers of the Directors herein contained shall not affect any action, step, resolution or by-law duly taken, made, passed or consented to by the Directors prior to the Effective Date.

4. The Shareholder assumes all the rights, powers, duties and liabilities of the Directors to manage or supervise the management of the business and affairs of the Corporation in connection with the Restricted Powers and, pursuant to subsection 108(5) of the Act, the Directors are thereby relieved of their duties and liabilities, including any liabilities under section 131, to the same extent.

5. For greater certainty, the Restricted Powers do not restrict the duties and liabilities of the Directors to manage, or supervise the management of, the business and affairs of the Corporation relating to the actual implementation of any decision made by the Shareholder pursuant to paragraph 1 above, including:

(i) duties stemming from the Corporation's or HONI's licence conditions and all applicable instruments, codes and orders of the Ontario Energy

Board, as well as the regulations and legislation and any instruments issued pursuant thereto;

(ii) duties and liabilities associated with the prudent and cost-efficient operation by HONI of all of its transmission and distribution facilities;

(iii) duties and liabilities associated with the safe, reliable and environmentally responsible operation of all of HONI's transmission and distribution facilities;

(iv) duties to take appropriate decisions, actions or steps to implement this Declaration and any Resolution of the Shareholder made pursuant to this Declaration.

IN WITNESS WHEREOF the Shareholder has duly executed this Declaration as of the Effective Date.

HER MAJESTY THE QUEEN IN RIGHT OF THE PROVINCE OF ONTARIO, AS REPRESENTED BY THE MINISTER OF ENERGY

By:____________________
Brad Duguid
Minister of Energy

School Energy Coalition (SEC) INTERROGATORY #4 List 1

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

Interrogatory

[A-13-2/p.107/ss.11.2.8]
Did the Applicant make a submission to the Ontario Distribution Sector Panel? If so, please provide a copy of the submission.

Response

Yes. A copy of Hydro One's submission to the Ontario Distribution Sector panel is attached as Appendix A.

Distribution Sector Review Panel

Hydro One Inc. Submission

Table of Contents

1. Letter from Laura Formusa, President and CEO, Hydro One Inc.

Hydro One Inc.
483 Bay Street
North Tower, 15th floor
Toronto, Ontario M5G 2P5
www.HydroOne.com

Tel: (416) 345 6306
Fax: (416) 345 6054

Laura Formusa
President & CEO

June 29, 2012

Dear Panel Members:

On behalf of the Board of Directors and Management of Hydro One, thank you for providing an opportunity to make a formal submission to the Ontario Distribution Sector Panel.

As stewards of Ontario's electricity grid, Hydro One's mandate is to provide safe, reliable, cost-effective electricity transmission and distribution. The Company carries out its business in every corner of this province and operates in places where no other utility can or will. We own and operate the largest electricity transmission and distribution businesses in Ontario. Our distribution business represents approximately $7B in assets on total assets of $18B.

We are also an important provincial asset with a long history of creating value for the Province. Since 2003, Hydro One has paid approximately $2.25B in dividends to the Province of Ontario and has made payments in lieu of taxes of $1.5B to the Ontario Electricity Financial Corporation. In addition to the financial contribution the Company has made to the Province, the Company has also invested more than $8.5B in new infrastructure. Funding for these investments has been raised by Hydro One without any impact on the Province's borrowing requirements.

Hydro One is also a key enabler of this Province's Green Energy Act, and is expanding its current infrastructure so that Ontario can continue to take advantage of the clean and renewable energy potential in this Province. We have connected approximately 6,500 MW of renewable generation to date.

We are leaders and innovators. We are the go-to utility when people want to know about smart meters, Advanced Distribution Systems, network operations and storm recovery. Our expertise and advice in these areas are being sought the world over.

We constantly seek to drive productivity and efficiencies into our business to keep rates low for our customers. Consistent with our current business plan, we expect to achieve combined cost and productivity savings of $420M.

The discussion of these issues is timely and I applaud the Province for taking steps to look more closely at the distribution sector. We believe there is duplication and fragmentation in the sector that frustrates real efforts to reduce costs for our customers. The demographic issues, both people and asset age, contribute to the need to have this discussion now. It is not simply good enough to replace aging assets on a like-for-like basis. We must take this opportunity to invest in new technologies that will help us connect renewables, enable electric vehicles, address our aging infrastructure and, most importantly, put more choices in the hands of our customers.

Hydro One advocates a competitive, economic and commercial approach to dealing with the distribution sector and we are pleased to provide solutions. We are uniquely positioned to play a significant strategic role in managing these challenges given our past experience with respect to LDC acquisitions and the next generation business tools we could employ to facilitate consolidation.

The Ontario Distribution Sector Review Panel has some very challenging and complex questions with which to grapple. I wish you well in your deliberations and we look forward to learning about your specific recommendations.

Yours very truly,

L Formusa

Laura Formusa
President and Chief Executive Officer
Hydro One Inc.

2. Hydro One at a Glance

Hydro One **at a glance**

hydroOne

Mission and Vision

We will be an innovative and trusted company delivering electricity safely, reliably and efficiently to create value for our customers.

Our Strategy

Our corporate strategy is based on our mission and vision and our values. Our values represent our core beliefs, including Health and Safety, Excellence, Stewardship and Innovation. We have eight strategic objectives that drive the fulfillment of our mission and vision:

- Creating an injury-free workplace and maintaining public safety
- Satisfying our customers
- Continuous innovation
- Building and maintaining reliable, cost-effective transmission and distribution systems
- Protecting and sustaining the environment for future generations
- Employee engagement
- Maintaining a commercial culture that increases value for our shareholder
- Achieving productivity improvements and cost-effectiveness

Our Transmission Business (YE 2011)

- Owns and operates substantially all of Ontario's Tx system, accounting for about 97% of Ontario's capacity.
- Single Ontario Grid Control Centre located in Barrie, to manage Dx and Tx operations, opened August 2004.
- Our Tx system includes 286 transmission stations.
- Transmits electricity to customers consisting of 48 LDCs, our own Dx businesses and 93 Tx-connected companies. Transmitted about 141 TWh of energy in 2011, directly or indirectly, throughout Ontario.
- Sixty-minute system peak demand (MW) in 2011 was 25,450 achieved in July. The sixty-minute system peak demands in each of the previous four years were as follows: 25,075 (July 2010), 24,380 (August 2009), 24,195 (June 2008), 25,737 (June 2007). The all-time peak demand was 27,005 achieved on August 1, 2006. The Tx system is built to accommodate peak loads.
- Interconnections – linked to five adjoining jurisdictions through 26 inter-ties at 345 kV, 230 kV, 115 kV and 69 kV levels with New York (7), Quebec (11), Michigan (4), Manitoba (3) and Minnesota (1).
- In total, these interconnections can accommodate imports of about 4,600 MW and exports of about 6,000 MW of electricity. In operation, the actual import and export capabilities may be restricted significantly by limitations within our or another jurisdiction's Tx networks, unscheduled power flows between interconnected systems and local load and generation patterns.

Board of Directors

(AS AT DATE OF RELEASE, MARCH 30, 2012)

James Arnett (Chair)

Sami Bébawi

Kathryn A. Bouey

George L. Cooke

Laura Formusa

Janet Holder

Don MacKinnon

Michael J. Mueller

Walter Murray

Robert L. Pace

Gale Rubenstein

Douglas E. Speers

For biographies of Hydro One's Board of Directors, please visit our website at www.HydroOne.com

Hydro One Legal Entities

HYDRO ONE INC.
Laura Formusa, President and CEO

HYDRO ONE NETWORKS INC. (NETWORKS)
Laura Formusa, President and CEO

HYDRO ONE REMOTE COMMUNITIES INC. (REMOTES)
Myles D'Arcey, President and CEO

HYDRO ONE TELECOM INC. (TELECOM)
Paul Marchant, President and CEO

HYDRO ONE BRAMPTON NETWORKS INC. (BRAMPTON)
Remy Fernandes, President and CEO

Credit Ratings 2011

Rating Agency	Short-Term Debt	Long-Term Debt
DBRS Limited	R-1 (middle)	A (high)
Moody's Investors Service Inc.	Prime-1	Aa3
Standard & Poor's Rating Services Inc.	A-1	A+

Hydro One **at a glance**

Our Distribution Business (YE 2011)

- Spans roughly 75% of the province.
- Includes Hydro One Networks' Distribution Business, Hydro One Brampton Networks and Hydro One Remote Communities.
- Customers of the HONI Dx business include 23 LDCs not directly connected to our Tx system, 33 LDCs connected to our Tx system, 29 customers with loads >5 MW and about 1.4 million rural and urban customers.
- Own 1,008 Dx and regulating stations.
- Dx systems distribute electricity from our Tx system and from more than 7,800 small generators (240 generators >10 kW and approximately 7,600 <10 kW).
- Hydro One Brampton Networks serves approximately 138,000 urban retail customers located in Brampton.
- Hydro One Remote Communities operates 19 small, regulated Gx and Dx systems across Northern Ontario serving 21 remote communities that are not connected to Ontario's electricity grid, totalling approximately 3,500 customers.

Our Telecommunications Business

(YE 2011)

- Hydro One Telecom is a CRTC-registered, non-dominant, facilities based carrier that provides critical telecommunications related services to Hydro One Networks in support of its existing business, as well as its emerging Smart Metering, Smart Grid, Distributed Generation and North American Electricity Reliability Corporation Cyber Security needs.
- In addition to its own infrastructure, Hydro One Telecom also leverages Hydro One Networks' telecommunications assets to deliver state-of-the-art broadband telecommunications solutions to major carriers, independent service providers, and large public and private sector customers that value the inherent high reliability of its network.
- Its Ontario based fibre optic network spans over 5,700 kilometres with interconnects to Montréal, Buffalo and Detroit.

Transmission Regulation

(LICENCE APPROVED TO DECEMBER 2023)

- **2011-2012 Tx Rates** – On December 23, 2010, the OEB issued its decision effective January 1, 2011 approving revenue requirements of $1,346M for 2011 and $1,658M for 2012. Hydro One has received approval from the Ontario Securities Commission to use United States (US) Generally Accepted Accounting Principles (GAAP) for reporting in lieu of IFRS for the fiscal years 2012, 2013 and 2014.

  On November 23, 2011, the OEB issued its decision approving the use of US GAAP for regulatory purposes. In its decision, the OEB approved the creation of a new deferral account to track costs associated with the transition to US GAAP and a new variance account to record the 2012 impact of differences between Canadian GAAP and US GAAP. As a result of this decision, the Company's IFRS deferral and variance accounts

continued on next page

Major Projects

(DOLLARS REFLECT APPROVED BUDGET)

In 2011, approximately $1,350 million of capital assets were successfully placed in service. This includes the Vansickle TS Upgrade Project in the first quarter, which provides additional capacity to address load growth in the St. Catharines area and Bay 2 of the North switchyard at Burlington TS in the second quarter. During the third quarter, Static Var Compensators at Nanticoke TS, Detweiler TS and Kirkland Lake TS were placed into service.

Bruce to Milton ($695.5M Full Project Release) – Includes the construction of a new 500 kV double circuit line from the Bruce Power facility to Hydro One's Milton SS. On January 7, 2011, Hydro One informed the Ontario Energy Board (OEB) that as a result of the decision to deny the construction work-in-progress costing approach, the total projected cost would be revised to $755M. Real estate costs have been finalized and the anticipated total costs for the project are $705M. Projected I/S date: July 2012. Approved I/S date: 2012.

Woodstock Area Tx Reinforcement ($75.6M) – Construction of Karn TS, a 230 kV double-circuit line between Ingersoll TS and Karn TS, and a 230 kV double-circuit line between Karn TS and Woodstock TS to increase capacity and ensure supply reliability in the Woodstock area. Projected I/S date: April 2012. Approved I/S date: April 2010.

Smart Meters – As at December 31, 2011, 1,064,907 customers have been notified of their switch to Time-of-Use (TOU) pricing and 1,056,670 meters were consuming power on TOU rates. Hydro One met its June year-to-date target of 1.05 million meters. The next OEB target is set for the end of 2012 when all Hydro One customers should be consuming power on TOU rates.

Feed-In-Tariff (FIT) – MicroFIT applications received by the Ontario Power Authority (OPA) within Hydro One Networks' service territory have reached a total of over 25,000 projects (excluding withdrawn or ineligible OPA applications) as at December 31, 2011. Of these applications, more than 7,602 smaller generators, representing approximately 72,373 kW have been successfully connected, with more than 4,328 additional projects in progress. For FIT, 75 generators representing 12,225 kW have been successfully connected, with 634 generator projects in progress. Hydro One continues to assess the implications and develop potential solutions for the distributed generators on its system.

Transmission Regulation (continued)

will be discontinued. On December 1, 2011, Hydro One submitted to the OEB a draft 2012 transmission revenue requirement that reflects the approved adoption of US GAAP for rate-setting purposes as well as the OEB-directed update to 2012 cost-of-capital parameters. On December 20, 2011, the proposed $1,418 million 2012 revenue requirement was approved by the OEB along with new 2012 Uniform Transmission Rates effective January 1, 2012.

- **2013-2014 Tx Rates** – The current business plan for 2012 – 2016 assumes Hydro One will file a Tx cost-of-service rate application in April of 2012. The test years would be 2013 and 2014.

Distribution Regulation

(LICENCE APPROVED TO SEPTEMBER 2024)

HYDRO ONE NETWORKS INC.

- **2011 Dx Rates** – On December 21, 2010, the OEB released Hydro One's final rate order for 2011 rates that included a revised revenue requirement of $1,218M, which was adjusted to reflect the OEB's decision to decrease OM&A by $40M and to reflect a $44M capital program reduction. The rate order was also adjusted for the new ROE value of 9.66% as issued in the OEB's cost of capital parameter update for rates effective January 1, 2011. The approved 2011 revenue requirement resulted in an average Dx rate increase of about 8.7%, or 3% on an average customer's total bill.

- **2012–2014 Dx Rates** – In its November 23, 2011 Transmission Business decision, the OEB indicated that it would consider a stand-alone application by Hydro One requesting the extension of the use of the US GAAP standard to its Distribution Business. On December 1, 2011, Hydro One Networks provided evidence to the OEB in support of its request for approval to use US GAAP for rate setting, regulatory accounting and reporting purposes within its Distribution Business. It was estimated that the 2012 notional Hydro One Distribution revenue requirement would be about $166 million higher if modified IFRS were utilized rather than US GAAP. On March 23, 2012, the OEB approved Hydro One Networks' request to adopt US GAAP as the basis for regulatory accounting and reporting in its Distribution Business, consistent with an earlier approval given to its Transmission Business. The Company is not requesting any change to its approved distribution rates at this time as it continues to explore and consider various filing options for its distribution rate application.

HYDRO ONE BRAMPTON NETWORKS INC.

- **2012 Rates** – On September 15, 2011, Brampton submitted an application for rates on the basis of the OEB's 3rd Generation Incentive Regulation Mechanism (IRM). In its application, it requested approval for a Lost Revenue Adjustment Mechanism and disposal of the provision for payments in lieu of corporate income taxes regulatory account balance. On December 22, 2011, the OEB issued its decision on the application, directing Brampton to file a draft Rate Order which was filed on December 28, 2011 and on December 31, 2011, the OEB declared Brampton's existing rates interim as of January 1, 2011. On January 5, 2012, the OEB issued its final Rate Order, approving the 2012 rates submitted by Brampton that resulted in a reduction in rates of approximately 13.2%, or 1.7% on an average customer's total bill.

HYDRO ONE REMOTE COMMUNITIES INC.

- **2012 Rates** – On November 25, 2011, Remotes filed an application for 2012 distribution rates with an effective date of May 1, 2012 under the OEB's 3rd generation IRM policies. The application seeks an increase of approximately 0.4% on an average residential customer's overall monthly bill. Consistent with the OEB's decision affirming the use of US GAAP for rate-setting purposes for the Transmission Business, on December 15, 2011, Remotes filed a stand-alone application seeking approval for the adoption of US GAAP for regulatory purposes.

OEB Developments

Distribution System Code (DSC) Exemption – On October 11, 2011, the OEB issued its decision pertaining to an application Networks filed on April 19, 2011, requesting an exemption from the timelines in the DSC related to the connection of micro-embedded generation facilities. The decision increases the timeline for processing indirect connections that require a site assessment from 15 days to 30 days. Prior to connecting the micro-embedded generation facilities to the distribution system, connections must now be performed on the date agreed with the customer or within five business days from the day on which all applicable service conditions are satisfied. The exemption expires on April 11, 2012. On November 15, 2011, Networks submitted its Compliance Plan to the OEB. On December 14, 2011, the OEB directed Networks in its Final Order to file a compliance report on a monthly basis starting January 2012 until Networks has met the DSC requirements for three consecutive months.

Long Term Energy Plan (LTEP) – Hydro One Networks Tx Licence Amendment – On February 28, 2011, the OEB amended Hydro One's Tx licence as directed by the Minister of Energy, to accommodate the Tx projects listed in the LTEP. The amendment states that Hydro One will develop and seek Section 92 approvals in accordance with the OPA's recommendations for two projects: upgrading one or more existing Tx lines west of London, and building a new Tx line west of London. The amendment also states that Hydro One will develop and implement two other projects to enhance transfer capability in Southwestern Ontario and increase short circuit and/or transformer capacity at up to 15 Tx stations during a 48-month period commencing March 1, 2011. On April 14, 2011, Hydro One filed the OPA's advice letter regarding the priority list of stations as requested by the OEB.

On April 19, 2011, Hydro One's sole shareholder, the Province of Ontario, made a declaration pursuant to subsection 108 (3) of the *Business Corporations Act (Ontario)* pertaining to the cost recovery of the expenditures related to the above licence condition amendment. The declaration restricts the rights, powers and duties of the Company's Directors in seeking or permitting any cost recovery for up to 15 transformer stations specified in the OEB directive from microFIT and small-scale FIT generation project proponents or from electricity consumers. In addition, the Company's Directors are restricted in pursuing or implementing internal cost recovery or cost mitigation measures designed to offset the costs, including cost minimization strategies to increase overall cost efficiencies within the Company.

On June 30, 2011, Networks received a letter from the OPA providing it with a recommendation on the scope and timing of the West of London Transmission Upgrade Project to enable the connection of approximately 300-500 MW of additional renewable generation in the west of London area. The required in-service date for the upgrade is December 2014. On March 28, 2012, Networks filed a Section 92 application for this project with the OEB.

On October 3, 2011, the OPA issued a letter providing Networks with the scope and timing of the Southwestern Ontario Reactive Compensation Project recommending that it proceed to add an SVC to the 500 kV voltage level at its Milton Switching Station to increase the capability of the Bruce transmission system. The SVC is anticipated to be in-service by the spring of 2015. Networks is currently awaiting an OPA recommendation regarding the construction of a new transmission line west of the City of London.

In addition, Networks received another letter dated October 3, 2011, from the OPA recommending the development of an implementation plan for installing additional 500-230 kV auto-transformer capacity within the east Greater Toronto Area (GTA) by the spring of 2015. This Oshawa Area Transformer Station Project will facilitate reliable supply load to the east GTA.

Competitive Transmission Project Development Planning – On March 29, 2011, the Minister of Energy expressed the Province's interest in the OEB commencing a designation process for the East - West Tie (E-W Tie) Line. On August 22, 2011, the OEB issued a notice to all interested parties inviting all licenced transmitters to indicate their interest in filing a development plan for this project by September 21, 2011. On September 19, 2011, Hydro One signed a memorandum of understanding with other parties to create a venture to pursue development of the E-W Tie and formed a limited partnership named EWT LP. On September 21, 2011, EWT LP, having previously applied for a transmission licence, registered its intent with the OEB to participate in the E-W Tie designation process. In January and February, the OEB convened a series of meetings with all potential bidders along with the OPA, the IESO and incumbent transmitters to discuss the specifics of the process.

Renewed Regulatory Framework for Electricity Distributors and Transmitters – On December 17, 2010, the OEB initiated a coordinated consultation process for the development of a renewed regulatory framework for electricity distributors and transmitters. The OEB's objective is to encourage and facilitate greater efficiency through a focus on performance-based outcomes and a disciplined, long-term approach to network investment planning. This effort is intended to help ensure the reliable and cost-effective delivery of electricity to Ontario consumers.

On November 8, 2011, the OEB released five staff discussion papers and supporting consulting reports that are intended to initiate dialogue with stakeholders. These papers and reports looked at many issues including: distribution network investment planning; regional planning; smart grid; rate mitigation/smoothing; and performance measurement. The anticipated outcome of this initiative is a regulatory framework with several potential areas of change including rate design, system codes, cost allocation, cost responsibility, reporting requirements, and performance measurement matrix.

The OEB hosted a two-day information session for stakeholders on December 8 and 9, 2011, in which Hydro One participated and provided feedback. On February 6, 2012, the OEB released a "straw man" Regulatory Framework Model which provides a high-level illustration of the way in which the main components and outcomes discussed in the five staff discussion papers might be brought together in a coherent, internally consistent manner that highlights linkages between outcomes, defined performance, measured performance and potential regulatory mechanisms.

The OEB will also be hosting a series of meetings in late February and early March of 2012 with interested stakeholders to have a discussion at a strategic and conceptual level about the development of this initiative. Once these meetings have concluded, the OEB plans to hold a Stakeholder Conference in late March 2012 at which all stakeholders will have the opportunity to discuss issues relating to the development of this initiative.

Hydro One **at a glance**

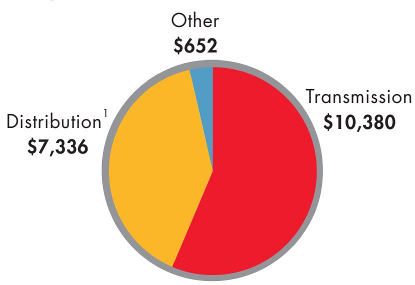
hydroOne

Five Year Summary of Consolidated Financial and Operating Statistics[1]

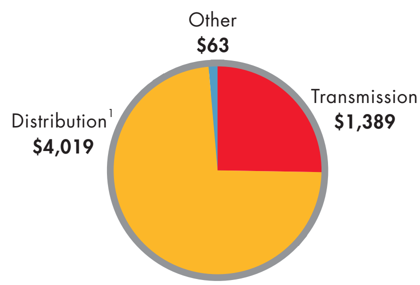
Actual $M	**2011**	**2010**	**2009**	**2008**	**2007**
Total Revenue	5,471	5,124	4,744	4,597	4,655
OM&A	1,092	1,078	1,057	965	995
Purchased Power	2,628	2,474	2,326	2,181	2,240
Other Expenses[2]	1,110	981	891	953	1,021
Net Income	**641**	**591**	**470**	**498**	**399**
Total Assets	18,368	17,322	15,635	13,878	12,786
Preferred Dividend Paid	18	18	18	18	18
Common Dividend Paid	150	10	170	241	307
Capital Expenditures	1,447	1,570	1,566	1,284	1,091
Preferred Equity	323	323	323	323	323
Common Equity + Retained Earnings	6,141	5,668	5,105	4,811	4,572
GAAP ROE (%)	10.5	10.6	9.1	10.2	8.4
Regular Employees	5,781	5,717	5,427	5,032	4,602
Transmission:					
Units Transmitted (TWh)	141.5	142.2	139.2	148.7	152.2
Total Transmission Lines (cct-km)	28,942	28,951	28,924	29,039	28,915
Ontario 60-minute System Peak Demand (MW)	25,450	25,075	24,380	24,195	25,737
Distribution:					
Units Distributed through Lines (TWh)	42.5	42.5	43.5	44.7	45.7
Total Distribution Lines (cct-km)	120,514	123,552	123,528	123,260	122,933
Customers	1,365,379	1,345,177	1,333,920	1,325,745	1,311,714

1 Operating statistics and GAAP ROE are reported annually
2 Consists of depreciation, amortization, financing charges and PILS

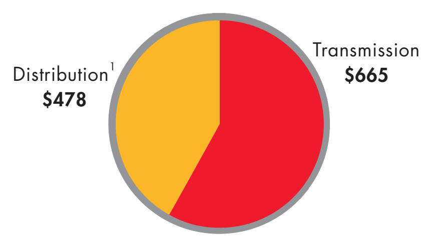
Segmented Financial Information



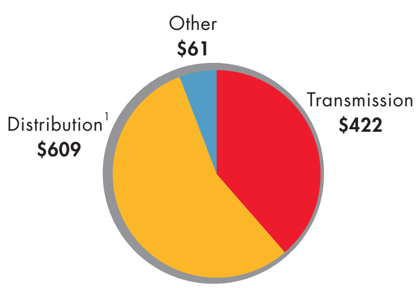
Total Assets $18,368
2011
(CAD $ millions)



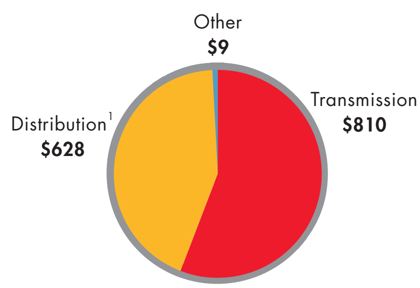
Revenue $5,471
2011
(CAD $ millions)



EBIT[3] $1,143
2011
(CAD $ millions)



OM&A[2] $1,092
2011
(CAD $ millions)



Capital Expenditures $1,447
2011
(CAD $ millions)

1 Includes Remotes and Brampton
2 Includes Remotes fuel costs
3 Excludes EBIT of ($8)M for Other segment

3. Hydro One's Submission to the Distribution Sector Review Panel

Introduction

On April 13, 2012, the Province of Ontario announced it was launching a comprehensive review of the province's electricity sector. This review was first announced in the 2012 Budget. Consistent with this effort, the Minister of Energy announced the establishment of the Ontario Distribution Sector Review Panel. The Review Panel will:

> *"explore options to provide advice and make recommendations to the Minister of Energy regarding issues related to Ontario's electricity distribution sector and distribution models, including opportunities for consolidating distributors."*

The panel will also consult with municipalities, Hydro One, Local Distribution Companies (LDCs), the Electricity Distributors Association and other energy experts, and look at a range of issues including:

- Potential long- and short-term financial savings associated with consolidation
- Benefits for ratepayers
- Long- and short-term operational efficiencies
- Potential risk

On May 4, 2012, the Review Panel issued the *Ontario Distribution Sector Panel Stakeholder Guidance Document* to seek input from stakeholders and indicated it would meet with various groups. The Review Panel asked stakeholders to respond to the following questions in their submissions:

1. Do you have a position on possible approaches to restructuring the utility sector, which is based on data or experience?
2. How might such restructuring be arrived at?
3. What would the costs and benefits be of such restructuring, with particular regard to the electricity ratepayer?
4. What implementation issues and/or risks should be considered?
5. What principles should govern restructuring?
6. Do you have any further research to share with the Panel to support your position?
7. How can utility innovation be encouraged to ensure that utilities are prepared to meet the needs of the 21st century while providing maximum value to customers?

Hydro One executives and Board Chair met with the Panel on June 5, 2012, to discuss Hydro One's responses to the questions above. The following document sets out in detail Hydro One's recommended approach to sector restructuring and represents Hydro One's formal submission to the Ontario Distribution Sector Review Panel.

Context

The electricity distribution sector in Ontario has undergone periods of considerable consolidation in the past 15 years. In 1998, there were more than 300 LDCs. Since 1998, the number of licensed municipally owned electric utilities in the province has fallen from 305 to 74 distributors (including Hydro One). Today, these distributors deliver power to 4.8M residential, commercial and institutional customers.

Consolidation efforts stalled in the middle of the last decade resulting in continuing fragmentation of the sector. Currently, 74 LDCs provide service to customers across the province and the largest 8 LDCs serve 75% of the Province's electricity consumers.

Average rate base for all Ontario LDCs is $182.7M, yet 54 LDCs have rate base under $100M, and of these 54 LDCs, the average rate base is $26.5M. Including Hydro One, 15 LDCs have a rate base above $100M, and in this group, the average rate base is $426.6M. Put another way, 78% of LDCs in Ontario represent 12% of the total rate base in Province.

Conversely, the four largest Ontario LDCs, Hydro One ($5,562M), Toronto Hydro ($2,447M), Powerstream ($800M), and Ottawa ($634M), comprise 68% of the total rate base.

When compared against other Canadian jurisdictions, Ontario has almost twice as many LDCs (74) as all the remaining provinces combined (43) and these 74 LDCs serve half as many customers (4.8M) as all other provinces combined (approximately 10.5M). In other words, Ontario has twice as many LDCs serving half as many customers as the rest the country in total.

In addition, LDCs are facing legacy issues with respect to the state of their distribution infrastructure. The existing North American electricity infrastructure was built, to the greatest extent, throughout the 1950s and 1980s. These assets have served Ontario's communities well, but are reaching end-of-life and are not keeping pace with new technologies. Over the next 20 years, utilities will have to refurbish, replace and upgrade the existing electricity infrastructure.

In February 2012, the Conference Board of Canada issued a report prepared for the Canadian Electricity Association. The report, entitled: *Shedding Light on the Economic Impact of Investing in Electricity Infrastructure*; estimated Canadian utilities will need to make infrastructure investments of $347.5B by 2030; $62.3B of which, would be needed in distribution systems. For its part, the report indicated that Ontario would require distribution investments of $20.6B

Instead of replacing distribution infrastructure on a like-for-like basis, Ontario LDCs will need to be utilities of the future, by building and operating the next generation of distribution infrastructure, incorporating renewables and technologies that drive efficiencies into the business – all with a view to keeping rates low while improving the customer experience.

Not all utilities in this province are equipped to meet these current and future challenges. As it currently stands, Ontario's electricity distribution sector is fragmented and as a result, many of its players cannot keep pace with these new imperatives nor do they have access to the capital to take advantage of the opportunities they present. As a result, some Ontario customers will have the opportunity to experience the utility of the future and others will be left behind.

The current landscape is costly and is not sustainable. Nor is it an environment conducive to establishing a contiguous, consistent, modern, flexible distribution system that will benefit Ontario's electricity customers.

This submission

This paper lays out Hydro One's best advice on *how* to restructure Ontario's Distribution Sector; however, we feel it is important to first address the question *why*. In our opinion, the *why* is all about the customer. For this reason, Hydro One chose to first respond to the Panel's question regarding innovation and meeting the needs of the 21st Century while providing maximum value to customers.

Ontario electricity consumers have experienced an unprecedented period of change (smart meters, time-of-use billing) against a backdrop of rate increases to support much-needed electricity infrastructure investment. While many customers understand the need for investments, there is a persistent contention that the industry could be doing more to keep rates low while improving the customer experience.

Hydro One believes that innovation and the prudent application of proven technologies to this business represent the shortest road to providing customers with more choice and an improved experience.

The Utility of the Future

For more than ten years, Hydro One has been using innovation and technology to build the foundation of the utility of the future. The Company has built a technological roadmap that delivers this future state, the primary drivers of which have been to drive more productivity into our business, improve the customer experience and to ensure we have real-time data and analytic capability to make prudent investment decisions about our assets. The Company is developing tools to create a mobile workforce; introducing geo-spatial technology and asset analytic tools to make decisions about asset condition and investment; replacing its Customer Information System (CIS) with a system to collect and analyze customer data so that we can develop tailor-made products and services for our customers, different needs.

All of these capabilities are scalable to any size or type of utility and work from a single, integrated SAP platform. Several of the larger LDCs have made similar investments and are also positioned to achieve a similar level of functionality. The smaller LDCs in the province are not well-positioned to make these investments. These types of undertakings by smaller utilities would be duplicative and would result in unnecessary costs for the sector and by extension, for customers.

One of the most transforming initiatives Hydro One has embarked on, is the establishment of an Advanced Distribution System, known to some as a Smart Grid.

Advanced Distribution System

Hydro One's electricity distribution system was initially designed more than 100 years ago and has evolved over time to meet new and increasing demands using the best information and technology available. It has served Hydro One customers well over these years. However, the system is aging and in need of renewal with many of its component parts reaching the end of their lifespan.

At the same time this investment is needed, the demands being placed on the electricity system are changing— a result of a convergence of technological advancement, policy direction, market forces, the need to reduce our carbon footprint and most importantly, the need to put more choices in the hands of our customers. For this reason, simply replacing aging equipment with "like for like" is not a viable option.

The explosive growth of computing capabilities and broadband wireless telecommunications has opened up whole new worlds of possibilities to improve power distribution – to make it smarter, self-healing and more flexible. Hydro One has, for many years, applied this thinking successfully to its transmission system and we are well on the road to do the same on our distribution system through our Advanced Distribution System (ADS) project.

Building on the system's foundation with intelligent equipment at an incremental cost, Hydro One is renewing its distribution system to meet the future needs of the province and of Hydro One's distribution customers. The use of advanced sensing, automation, and wireless communication is essential in order to enable renewable distributed generation while maintaining reliability, improving equipment performance, restoration times, power quality, and ultimately, customer service.

It all started with the Smart Meter

Ontario's leadership in smart meters represents an essential first step in realizing the benefits of a smart grid for consumers. Almost all of Hydro One's 1.3M residential and small business customers now have a smart meter.

Hydro One customers now have the ability to access their hourly electricity consumption the day after they use it. This encourages customers to shift consumption to take advantage of lower off-peak prices and will lead to more efficient use of existing grid infrastructure and generation assets.

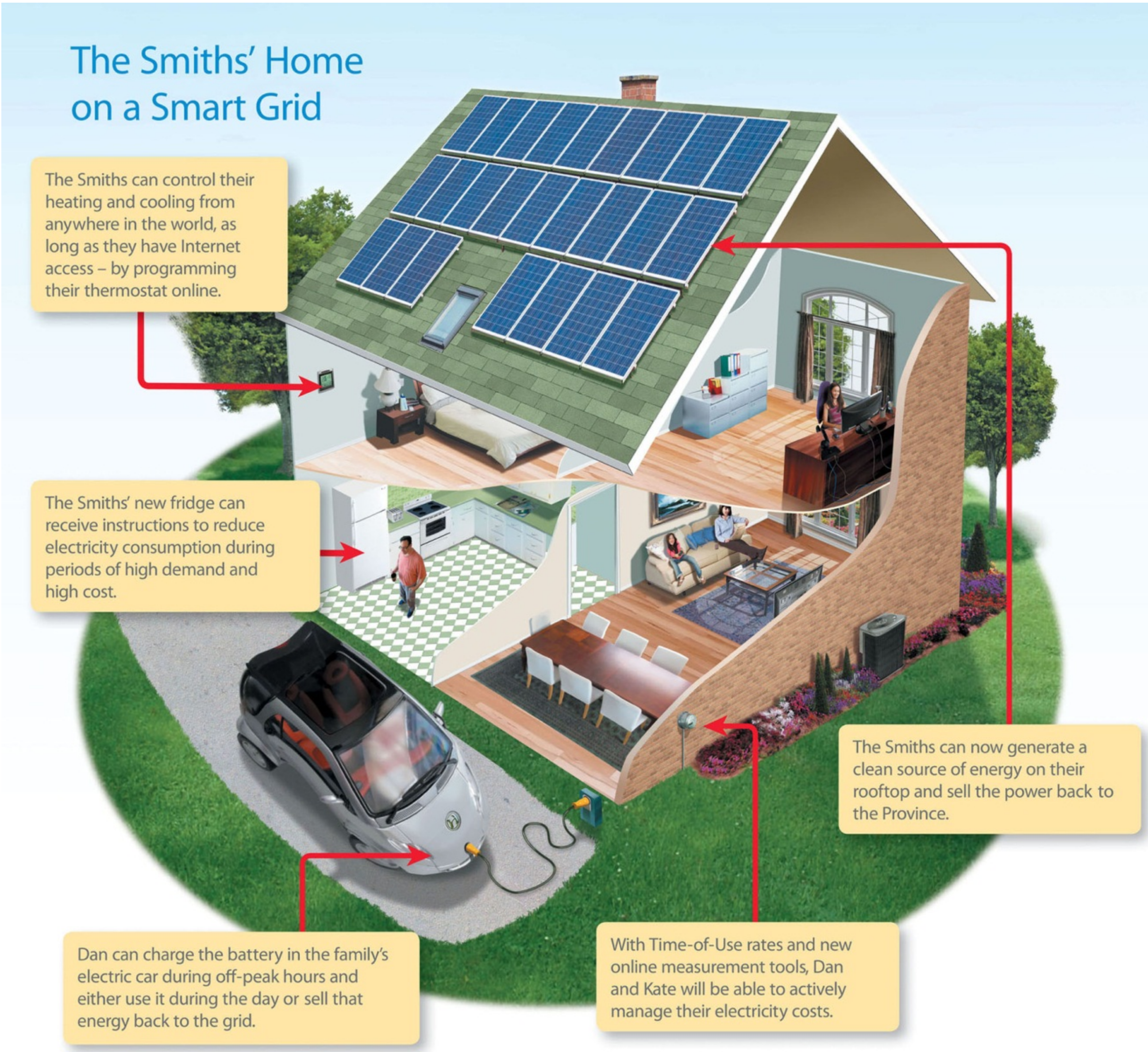
The smart meter data provides asset utilization information about Hydro One's system that was not previously available. The convergence of the flow of electricity and the flow of information lead us to a Big Data picture that could provide opportunities to create new products and services for electricity consumers.

Building on our smart meter success, Hydro One is continuing to move forward with our ADS project. This project marks an historic first step in modernizing our distribution system and realizing our vision of a smart grid—a grid that will enable the safe and reliable operation of renewable generation currently being built across the province, enhance system reliability, make available data that will keep rates as low as possible in the future and ultimately transform our relationships with customers.

Together with private sector partners GE, IBM, and Telvent, Hydro One has marshalled some of the best thought leaders in the industry to analyze, identify, and deploy applications, equipment, and processes in support of optimizing the connection of distributed generators into Hydro One's rural distribution system, improving reliability and operations, and optimizing outage restoration and network asset planning.

Our efforts have earned us multiple awards and international recognition. Hydro One has been a destination for close to 100 utility representatives from around the Globe (US, Europe, Australia, China) focused on gaining knowledge about smart meter/grid best practices. In fact, Hydro One has to its credit a world first achievement in securing wireless spectrum for use by the utility sector in Canada. The Company is also a leader in Smart Grid security having co-authored Smart Grid White Papers with the Privacy Commissioner of Ontario.

All of this work means nothing until you can make it work for the customer; until you can show them how these new systems will add value to their lives and give them more control over their electricity use and consumption. The diagram below shows what the customer's experience looks like when we use smart grid technology to put control back into the hands of the customer.



All Ontario electricity consumers should have the opportunity to experience the utility of the future

There is no doubt that every utility puts their customers at the centre of every decision, but this fragmented marketplace means that not all Ontario electricity consumers will have the opportunity to benefit from the myriad types of service and choices as LDCs have varying degrees of capability as it relates to innovation and establishing a utility of the future. As a result, some Ontario customers will have the opportunity to experience the utility of the future and others will be left behind. Hydro One is uniquely positioned to provide this capability to other players in the marketplace at low, incremental cost.

Hydro One believes the first step in realizing this future state is to restructure Ontario's Distribution Sector.

Hydro One supports restructuring Ontario's Distribution Sector

Hydro One would support a decision to restructure Ontario's Distribution Sector and has specific views with respect to the role it can play in facilitating a restructuring.

Regardless of the approaches ultimately identified and recommended by the Review Panel, Hydro One recommends the following principles govern any subsequent activity:

- Ratepayers come first and must be "held whole"
- Restructuring transactions must be on competitive, commercial and economic terms with fair and transparent links between cost and price
- Regulation will be consistently applied to all LDCs
- Recognition of the complexity and impact of technology on the sector:
  - Scalable systems
  - Ability to re-use capital

Significant benefits have been gained through restructuring in the past 15 years; however, substantial potential remains to be realized. Hydro One believes there are important synergies that can be achieved through further restructuring of the sector, the benefits of which, would accrue to customers and shareholders. Consolidation would result in immediate downward pressure on overall electricity costs, by reducing the overall cost to provide the service and by reducing the associated overhead costs to regulate and manage the distribution sector in Ontario. Some of these benefits include:

Administrative and Back Office

Reducing the number of players in the sector would allow for a significant reduction in corporate and administrative overheads. Consolidating the operations of many electricity distributors would allow for more efficient use of a smaller number of call centres, billing systems, payroll, accounting systems, procurement, warehousing, etc.

With respect to procurement, there is an opportunity for Hydro One and LDCs to consolidate procurement activities for certain common, standard materials (poles, transformers, insulators, etc). Savings could be achieved by negotiating more favourable pricing based on buyer power and by reducing overhead to manage this function. This activity could also extend to logistics, inventory management, transport, warehousing, etc. Hydro One expects this could yield 6% savings on $500M of spend per year.

Regulation

Reducing the number of regulated entities in the system would have a dramatic impact on the costs of operating the Ontario Energy Board (OEB), which currently has regulatory oversight for 74 different distribution companies, a majority of which have fewer than 25,000 customers. It would also enable a more consistent application of regulatory codes and requirements across a smaller group of utilities.

Coordination

Reducing the number of regulated entities in the system would have an impact on the operating costs of the Ontario Power Authority and the Independent Electricity System Operator in the following areas:

- f settlements
- meter data management repository (MDMR)
- conservation and demand management (CDM)
- regional planning
- distributed generation

Our previous successes

Hydro One's experience in acquisition of LDCs is unparalleled in the province. As noted above, in 2000/01, as part of an overall effort to rationalize the number of LDCs in Ontario, Hydro One made 170 proposals and successfully acquired 89 embedded LDCs at a multiple of 1.15 times rate base. In doing so, Hydro One was able to eliminate, on average, 30% of acquired LDC operating costs. This 30% savings did not include the savings in capital expenditures or the additional savings and efficiencies derived from regional planning. As a result of these acquisitions, the Company saw a post-consolidation increase in Hydro One's overall efficiency that resulted in an 11% reduction in OM&A per customer.

These estimated annual savings were attributed to operational efficiencies resulting from the elimination of duplication in fleets, supervision, operation centres, billing and collecting and rationalizing service workforce. The Company successfully integrated the majority of represented staff into its operations with overall savings offsetting labour costs. Additional savings were achieved through workforce optimization – more customers in the same territory permits more efficient work planning allowing operations staff to spend more wrench-time and less travel-time.

Post transaction, the Company conducted transactional surveys of acquired customers. Approximately 92% of municipalities that sold to Hydro One were "very satisfied" or "somewhat satisfied" with the transaction. At the time, our newly-acquired customers had a higher satisfaction level than our legacy customers. Current satisfaction of acquired customers is on par with, or better than, our legacy customers.

Testimonial - most recent acquisition of Terrace Bay in 2007:

"This is a good deal for both Terrace Bay and Hydro One," said Mike King, Mayor, Township of Terrace Bay. "Hydro One has committed to investing in our electricity delivery system and providing the high level of service that our citizens and businesses deserve. The funds from the sale can be put to good use in community projects and capital investments."

Hydro One can facilitate restructuring

Clearly, fewer LDCs would reduce overall sector costs. In fact, a single utility could serve the entire province. Hydro One believes the most significant synergies and savings could be achieved if it were to acquire the smaller embedded LDCs within its territory.

Currently, there are approximately 40 smaller LDCs serving approximately 500K customers. The vast majority of these LDCs are embedded within Hydro One Networks (HONI) territory (HONI is the largest of the regulated utilities owned by Hydro One). This fragmentation results in significant duplication with respect to operating centres, fleet, back office systems, etc., the cost of which is being borne by customers.

Integrating currently contiguous or embedded distributors would allow for significant capital efficiencies, by optimizing the number and location of distribution stations, feeder lines, switching equipment, smart meter networks, and control centres. Reductions in OM&A could also be achieved through rationalization of operations and maintenance personnel as a large number of them prepare to retire.

Hydro One already operates in both rural and urban centres across the province, servicing 650,000 sq.km (~95% of Ontario). In fact, 80% of all LDCs are within 40km of an existing Hydro One operating centre.

Hydro One's network of operation and field business centres span the province, covering a service territory 20 times the size of all other LDCs combined.

The Company successfully centralized operations and emergency response through the establishment of the world-class, state-of-the-art Ontario Grid Control Centre (OGCC) in Barrie. The initiative saw the consolidation of 34 centres to one centre. Operating staff were brought to this single location, reducing staff requirements by 40%.

Hydro One has a highly-skilled and experienced province-wide workforce that is trained to work in both Transmission and Distribution. The Company's Transmission expertise has clearly benefited our Distribution business, particularly in establishing an Advanced Distribution System. This integration also allows the Company to achieve synergies and productivity savings, thereby lowering our operational costs.

In addition, Hydro One's scalable back office capabilities (call centres, billing systems, payroll, accounting systems, procurement, warehousing, IT, etc.) could be leveraged to facilitate consolidation.

From our experience in 2000/01, Hydro One acquired 89 embedded LDCs and approximately 160K customers. This acquisition effort resulted in value creation of approximately $200M ($170M OM&A and $30M capital). On this basis, the acquisition of the small embedded utilities could represent a value creation opportunity of $400-$700M NPV (assuming an annuity of 6% and potential annual savings of $25M) thereby reducing the overall cost per customer. Value creation would be realized by:

- capitalizing on geographic synergies;
- maximizing productivity gains;
- protecting PILs;
- lowering cost of debt;
- reducing regulatory costs; and,
- decreasing industry costs related to settlements CDM and the MDMR.

With respect to cost to finance acquisition, based on an enterprise value of $1B -1.25B, the Company envisages supporting acquisition of the approximately 40 embedded LDCs through existing debt capacity with incremental leveraging in order to retain its 60/40 capital structure. The Company believes that incremental debt can be issued on favourable terms if value can be demonstrated.

Hydro One in the urban space: Hydro One Brampton

While the most immediate synergies could be achieved through the acquisition of the smaller embedded LDCs, Hydro One should continue to be part of the discussions regarding restructuring opportunities for urban utilities in the urban space. Hydro One has proven it is best-in-class in the urban space through its acquisition and ownership of Hydro One Brampton, previously Brampton Hydro. Hydro One Brampton is the 6th largest LDC in Ontario with a current rate base of ~$340M, serving approximately 135K customers.

Hydro One Brampton is in the top quartile with respect to:

- Total OM&A per customer: $150.37/customer – the 2nd lowest based on 2010 OEB Yearbook
- Reliability statistics such as System Average Interruption Duration Index (SAIDI) and Customer Average Interruption Duration Index (CAIDI): 19% and 10% respectively.

Using scalable back office capabilities can facilitate efficiencies and savings

Acquisition is not the only path to savings and efficiencies or to ensuring all customers can participate in a utility of the future. Ownership in and of itself does not have to dictate rates and prioritize investments. The provision of "back-office" or "operating" services to LDCs could provide the means to eliminate duplication and unnecessary costs in the sector. All utilities operate billing and settlement systems, and manage HR, IT procurement and outage management functions often from multiple platforms. There is a case to consolidate these services into a single scalable platform through one service provider.

Hydro One has invested significantly over the past 10 years to develop and apply next generation business tools and integrated, scalable technology platforms. Hydro One's approach to business transformation came out of the recognition there was a critical need for a common platform from which to operate our business and that we needed to improve the reliability and completeness of the information we held on our assets. Hydro One understood the need to have instant, accurate, complete, cross-referenced, analyzed data available with a limited number of key strokes.

Other electric utilities in Ontario face the same challenge of transforming their businesses, through the replacement of end-of-life information systems, each at a significant cost. Hydro One's deployed IT infrastructure has the existing capacity to absorb significant additional utilities at minimal marginal cost and can be extended even further with modest additional investment.

Hydro One is implementing a comprehensive Business Technology strategy to replace core "end-of-life" information systems and provide a platform for major business process transformation. It is this foundation of technologies that Hydro One continues to build upon to achieve significant productivity and efficiency gains across its business and allow for future expansion.

Utilities in Ontario share similar work practices. As each utility develops its individual information systems strategy to support their work practices, there will be duplication of functionality and excess capacity across these organizations at considerable expense. A single provider, such as Hydro One, could consolidate and deliver these services. Moreover, adoption of a common set of work practices will significantly reduce duplication of cost while at the same time quickly modernize the electric utility capabilities of the Province of Ontario, as follows below.

Productivity, cost-effectiveness and process efficiency

Hydro One has addressed business operation inefficiencies through the adoption of industry standard processes. It has not customized the business systems to accommodate current business processes; rather, Hydro One has replaced current business processes with industry standard practices that are fully supported by our new business systems. Cost-effectiveness is achieved with the reduction in material costs and material handling costs as well as IT application operating costs, which are significantly reduced by using standard processes. But it is not just about new technology and tools. Prior to introducing new technology, Hydro One has revamped its business processes to be more efficient and to generate value by streamlining business operations.

Better decisions

Better decision-making results from leveraging better information to optimize decisions on asset investments, system reliability and customer needs. To aid in enabling this objective, Hydro One has provided an integrated system of record and business intelligence reporting and analytics platform for asset and business data which allows for easier access to reliable data for developing investment strategies.

Protecting Hydro One customers within municipal boundaries

Clearly discussions with respect to acquisition of LDCs must always consider customer impacts, and in particular, rate impacts. As stated earlier, Hydro One believes that ratepayers come first and must be held whole in any transaction.

The issue of the cost to serve Hydro One customers within municipal boundaries has served as an irritant to some Hydro One customers and has been identified by other LDCs as the primary reason to acquire Hydro One customers. For this reason, it is important to address this issue in the context of the Panel's review.

Hydro One's cost to serve is competitive when scale of operations is considered. In fact, it is not only competitive, but much lower than the <u>average</u> OM&A per km across all LDCs:

- All LDCs: $6,842
- Hydro One: $4,524
- 18 Municipally-Owned Small LDCs: $11,456.
- 36 Medium LDCs: $8,944
- 15 large LDCs: $11,568

Hydro One's customer rates depend on the type of service they have, where they live and how much electricity they use – otherwise known as the "cost of service". As a largely rural utility, significantly more infrastructure is required to serve our customers as they are spread out over the entire province rather than contained within the borders of a municipality.

Effectively, the lower the customer density, the higher the cost of service. In Hydro One's case, instead of counting the number of customers who are served by a single pole, Hydro One counts the number of poles that serve a single customer. We have 1.3 M distribution customers and 1.7 million poles in our distribution system.

Prior to the early 1990s, Ontario Hydro was a vehicle for the development of rural electricity infrastructure. In accordance with government policy of that time, new customers could be allotted up to two kilometres of line extension free of charge. This resulted in a higher rate base per customer (Hydro One Networks $4,635/customer versus LDC average of $2,300/customer) and much lower customer density (almost 5x times less dense). As a result, the upward pressure on rates continues as these low density assets reach end-of-life and require both maintenance and capital expenditures.

Under *the Power Corporation Act*, this policy direction was backstopped through the Rural Rate Assistance (RRA) Program. This subsidy initially set the lowest density Ontario Hydro year-round (not seasonal) residential customer to within 15% of the municipal LDC average. The RRA, now Rural and Remote Rate Protection (RRRP) cannot keep pace with the cost differential between rural and urban customers.

This situation is further exacerbated as these earlier subsidized assets are now in need of replacement as they reach end-of-life and at today's costs. In its decision on HONI's 2010/2011 distribution rate application, the OEB directed HONI to provide a more detailed analysis of the relationship between density and cost allocation, and examine possible rate structures that appropriately reflect those differences. The results of the density study showed that the cost of serving a customer in a low density area is about five times the cost of serving a customer in a high density area. Hydro One's urban customers have been subsidizing the low density customers for many years and Hydro One believes that this situation needs to be corrected. In its 2013 distribution rate application, Hydro One has filed a revised allocation of costs to its density–based rate classes which would lower the urban residential customers' distribution rates by about 14%. If approved, this proposal would bring urban customers closer in line to our cost to serve them and more in line with municipal LDC rates.

Selling Hydro One assets would have to be based on commercial terms in order to preserve the value of the Company. A decision to sell assets on non-commercial terms to other LDCs would result in significant rate increases for Hydro One's remaining customers. Further, it is important to protect this part of our rate base in order to preserve the approximately $100M in annual synergies associated with operating an integrated transmission and distribution business. In other words, our workforce, as noted above, is an integrated transmission and distribution workforce capable of operating in both environments.

A decision to sell a large portion of Hydro One's distribution business could trigger a breach of the Company's corporate debt covenants. The breach would require the redemption of the existing corporate debt and would require the payment of an early redemption premium currently estimated to be in excess of $2 Billion. The redeemed debt and early redemption penalty would be financed through a market recapitalization consisting of a new debt issuance and the potential requirement for additional shareholder investment.

Conclusion

As previously stated, not all utilities in this province are equipped to meet the current and future challenges facing Ontario's distribution sector. As it currently stands, Ontario's electricity distribution sector is fragmented and as a result, only a small fraction of LDCs have the capacity to transform themselves into utilities of the future. Further, many do not have the internal capabilities or the access to capital to take advantage of opportunities that will benefit their customers. As a result, some Ontario customers will have the opportunity to participate in the utility of the future and others will be left behind.

The current landscape is not sustainable or affordable. Nor is it an environment conducive to establishing a consistent, modern, flexible distribution system required for Ontario's electricity consumers. As costs associated with updating and improving our generation fleet are introduced into rates, the pressures on our customers will increase even further and a solution must be found.

Hydro One is uniquely positioned to play an important role in the restructuring of Ontario's Distribution Sector. Our ability to leverage our scalable technology platform, capitalize on geographic synergies, preserve and maximize shareholder value, realize productivity gains, leverage our strong operating history, and our low cost of debt, position Hydro One well to play a leadership role in any subsequent consolidation activity.

Hydro One would like to thank the Ontario Distribution Sector Review Panel for its consideration of Hydro One's position. We remain available to meet and to discuss and/or clarify any of the issues or proposals raised in this submission. We wish you success in your deliberations and look forward to your recommendations.

4. Hydro One's Presentation to the Distribution Sector Review Panel

ONTARIO

Distribution Sector Panel

Hydro One Presentation

June 5, 2012

PART 1: CONTEXT

Principles Governing Restructuring

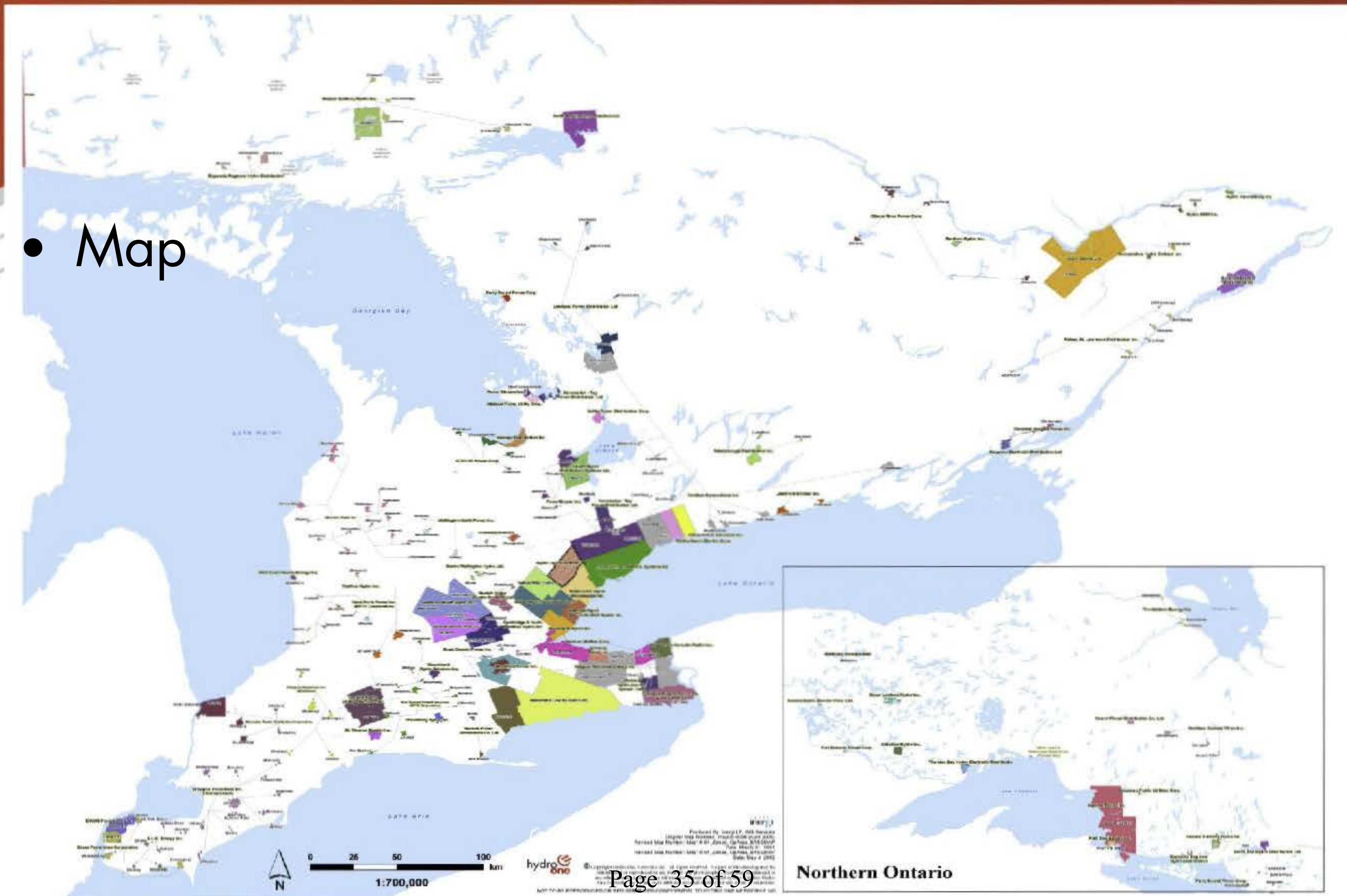
- Hydro One recommends the following governing principles:
  - The ratepayers comes first and should be held whole
  - Transactions must be on competitive, commercial and economic terms
  - The provision of a fair and transparent link between cost and price
  - Consistent application of regulation to all LDCs
  - Recognition of the complexity and impact of technology on the sector:
    - Scalable system
    - Ability to re-use capital

Providing Value to Customers

Solution	**Benefit**	**Cost**
Acquire Smaller Embedded LDCs (approx. 40)	• Value creation $400-700M NPV, based on previous experience • Available for rate reductions of approximately 1% and PILs • Geographic synergies maximizes productivity gains (~30%) • Further harmonization of rates	• Total enterprise value ~$1.25B • Possibly supported through existing debt capacity, with incremental leveraging to retain 60/40 capital structure • Incremental debt issued at reasonable cost if good value demonstrated
Protecting Existing Customers	• Protect fringe: remaining Hydro One Networks' customers would otherwise face significant rate increases • Preservation of integrated business = retention of ~$100M in synergies • Retention of Dx assets will not trigger debt covenants • Leverage ownership/experience with Hydro One Brampton	• Hydro One cost to serve is competitive when scale of operations is considered • Hydro One continues to develop rates and density-based rate classes that reflect the cost to serve
Back Office Capabilities	• Hydro One assets/expertise leveraged to offer services • Savings associated with avoiding replacement of LDCs end-of-life and redundant assets	• Hydro One's use of next generation business tools/technology = low incremental costs to scale

Ontario's Current Distribution Landscape

- Map

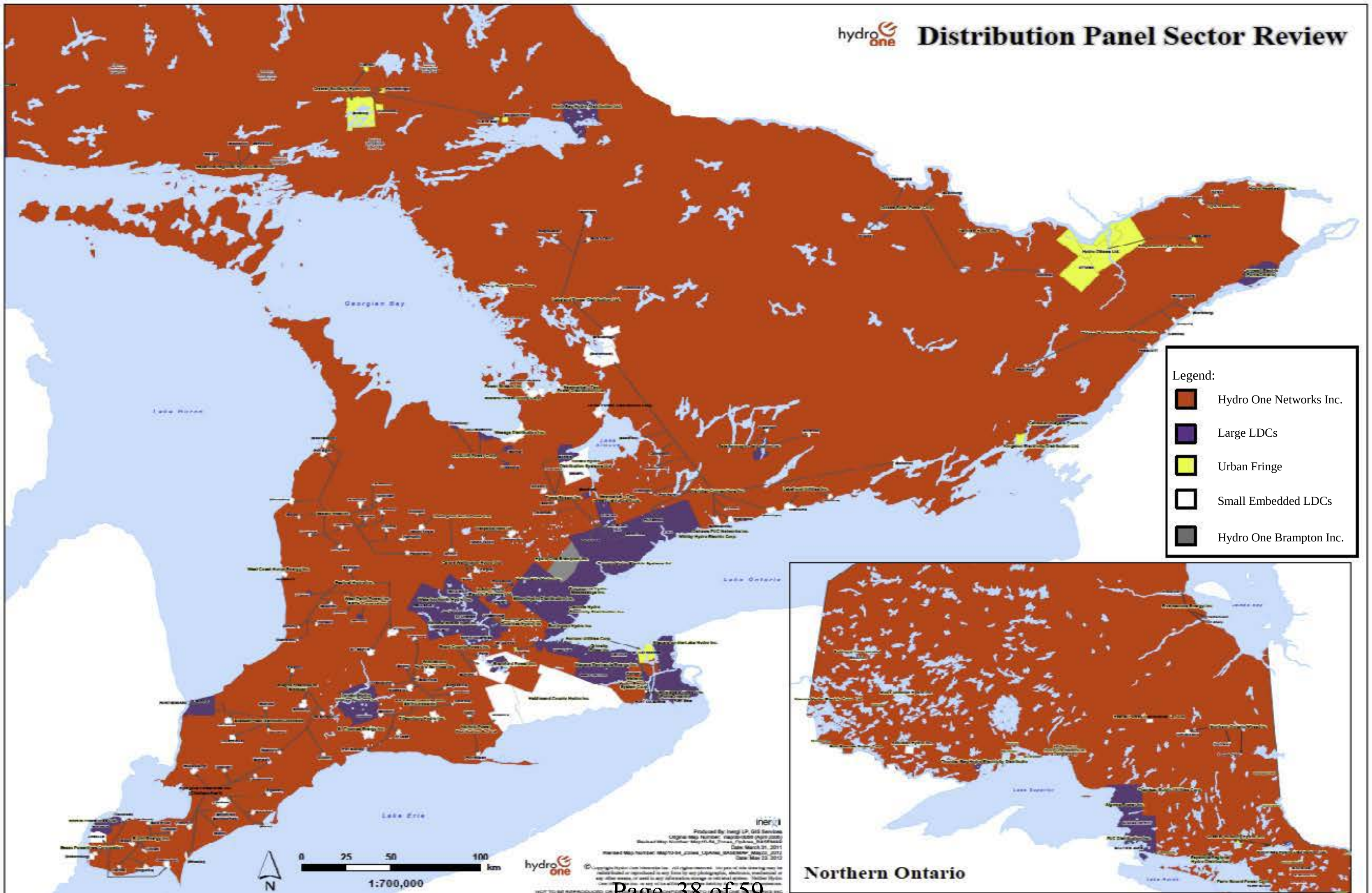


Ontario's Current Distribution Landscape (cont'd)

- Ontario's distribution territory is fragmented. There are opportunities for synergies.
- The current environment creates an opportune time for consolidation as most of the sector is facing significant demographic challenges:
  - the need for significant upgrades to distribution infrastructure
  - the increasing number of skilled and experienced staff eligible to retire
- Hydro One is uniquely positioned to handle these challenges:
  - given its significant success with previous acquisitions;
  - with its ability to leverage next generation business tools and technology platforms; and,
  - having already engaged in an aggressive workforce renewal program.

PART 2: HYDRO ONE’S APPROACH AND UNIQUE POSITION

Opportunities for Consolidation



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Hydro One's Approach

- Hydro One is well positioned to be a provincial consolidator outside the Greater Toronto Area (GTA) and Golden Horseshoe (GH).
- Our priority is to immediately achieve the most significant synergies and savings by starting with the smaller embedded LDCs in Hydro One Networks' territory.
  - Value creation opportunity of $400-$700M NPV, based on past experience
- Hydro One should continue to be part of the discussions regarding the urban space – Hydro One Brampton can play a role in the GTA and GH.
- In addition, Hydro One's back office capabilities could be leveraged to facilitate consolidation.

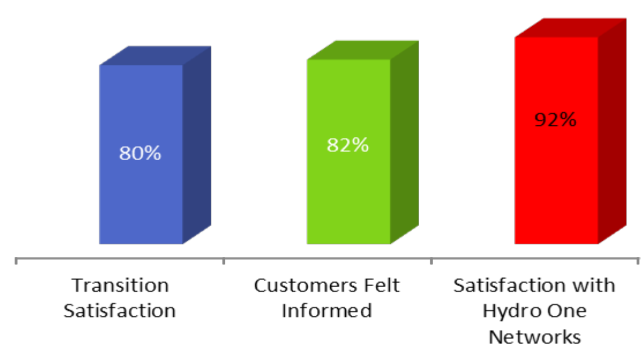
Our Unique Position: Operational Footprint

- Province-wide Presence:
  - In rural and urban centres; servicing 650,000 sq.km (~95% of Ontario)
  - Proximity of operation/field business centres - 80% of LDCs are within 40km of an existing Hydro One operating centre
- "State of the art" and centralized Ontario Grid Control Centre and Advanced Distribution System/Distribution Management System
- Highly skilled and experienced province-wide workforce
- Hydro's integrated Tx/Dx business has already driven and achieved synergies and productivity savings
- Scalable Back Office systems: Customer Information System, Asset Analytics, Asset Investment Planning, GIS, Finance, HR, etc.

Our Unique Position: We've Done This Before

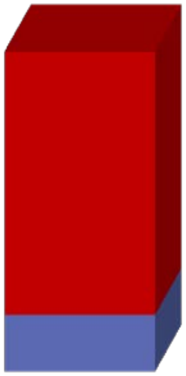
- Hydro One has a successful history of large scale LDC acquisitions
- The acquisition of 89 embedded LDCs from 2000/01 resulted in:
  - The elimination of an average 30% of acquired LDC operating costs and a significant increase in Hydro One's overall efficiency post consolidation ~ 11% reduction in OM&A per customer
  - Overall positive customer satisfaction results and successful integration of majority of represented staff into operations; savings offset labour costs
- Hydro One Brampton is best in class in the urban space

MEU Acquisiton Results 2000-2001			
	Hydro One Before	Hydro One After	% Change
Customers	957,000	1,202,000	26%
PP & E (NFA)	$2,593M	$2,990M	15%
Customers/Staff	198	230	16%
OMA/Customer	200	178	-11%



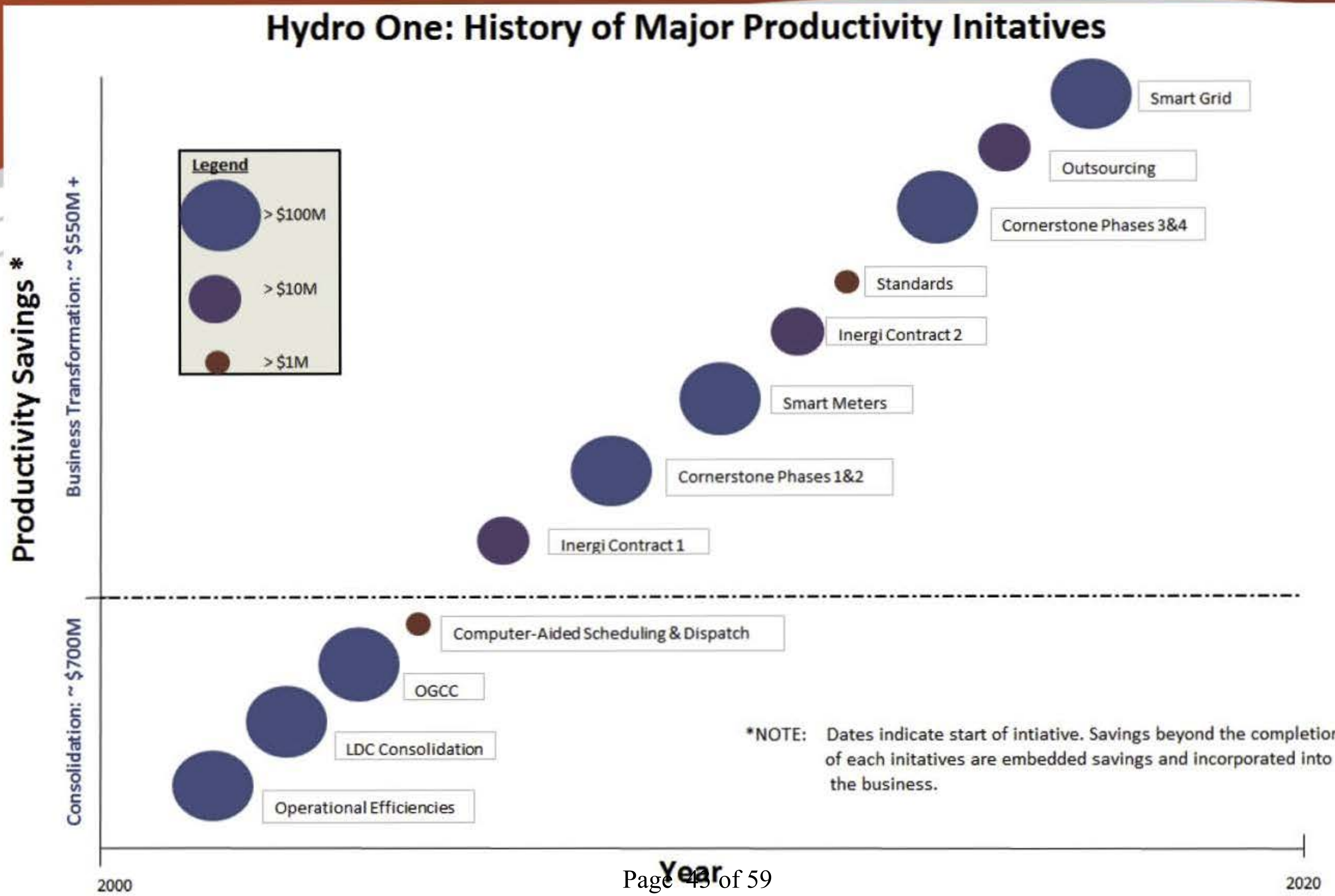
Our Unique Position: Ability to Scale

- The distribution business is changing, with increasing reliance on centralized “smart” systems and processes and technology
- The changing use of the distribution system requires distributors to invest in innovation to ensure ongoing success
- The LDC of the future requires the capital capacity to make these investments
- As such, scale is becoming increasingly important – new customers are added at variable cost, creating value now and into the future
- Hydro One has embraced this paradigm and is an industry leader in innovation



Cost per Customer (est.)	
Fixed	$809
Variable	$173

Our Unique Position: Innovating to Drive Productivity



Value Created Based on Further Consolidation by Hydro One

- Hydro One is the vehicle to capitalize on geographic synergies:
  - Maximize productivity gains of 30% through the reduction of operating costs in embedded territory
  - Resulting in an increase in overall efficiencies post consolidation
- Protection of payments in lieu of taxes going forward
- Savings associated with regional planning and standardized equipment/design as we renew distribution assets
- Share Hydro One's strong operating history and low cost of debt
- Reduced regulatory costs and efficiency in regulation
- Improved customer satisfaction
- Decreased industry costs (e.g. wholesale settlements, CDM, and MDMR)

PART 3: RISKS

Risk: Other Considerations

- Further fragmentation
- Regulatory
- Municipal buy-in
- Cherry-picking

Risk: Value Lost Through Further Fragmentation

- Sale of Hydro One Networks' fringe customers would cause the rates of remaining Hydro One Networks' customers to increase significantly
- Costs to disintegrate Hydro One's Tx and Dx business are significant: will trigger debt covenants (~$2B impact) and debt refinancing and loss of $100M in synergies
- Potential loss of payments in lieu of taxes to the Province
- Hydro One cost to serve urban customers is competitive when scale of operations is considered

Risk: Rates

- Prior to the early 1990's, Ontario Hydro (Hydro One) was a vehicle for the development of rural electricity infrastructure.
  - In accordance with government policy, new customers could be allotted up to two kilometres of line extension free of charge
  - This resulted in a much higher rate base per customer (Hydro One Networks $4,635/customer vs LDC average of $2,300/customer) and much lower customer density (almost 5x times less dense)
- The upward pressure on rates continues as these low density assets reach end of life.
- In recognition of this, Hydro One continues to develop rates and density-based rate classes that reflect the cost to serve, which allows the Company to be competitive with its urban counterparts.

PART 4: THE LDC OF THE FUTURE

LDC of the Future: Engaging Our Customers

Delivers	Hydro One's Approach
Opportunities to take part in a green energy economy	• Make investments (e.g. Smart Grid) and use acquired intelligence to enable DG
The continued delivery of reliable power at reasonable rates	• Make investments to automate the distribution system, allowing for increased efficiency • Use smart meters to reduce trouble call costs and improve response times • Leverage asset analytics to avoid unnecessary capital expenditures • Mobilize its workforce = more wrench time; less travel time
Opportunities for customers to be engaged partners; having access to information to realize benefits	• Use smart meters to provide customers with real-time in-home monitoring and new CDM programs

5. Facts and Figures

Facts and Figures

Context: Ontario's Local Distribution Company Landscape

LDC Data for Year ended Dec 31st, 2010	Hydro One Networks Inc.	Hydro One Brampton Networks Inc.	Private Ownership	Small LDCs Rate Base <$10M	Medium LDCs Rate Base $10M-$100M	Large LDCs Rate Base >$100M	Total
Number of LDCs	1	1	5	18	36	15	76
# of Service Territories	1	1	26	27	107	46	208
Non-Financial Stats							
Avg. Customers per LDC ('000)	1,203	134	13	4	22	168	63
Total Customers ('000)	1,203	134	65	68	799	2,516	4,785
Total Service Area (km^2)	650,000	269	14,502	1,304	8,476	7,063	681,614
Total GWh Purchased	25,146	3,911	1,273	1,681	18,584	75,774	126,368
Total km of Line	120,921	2,823	3,225	1,886	20,230	48,326	197,411
Financial Stats ($million)							
Revenue	3,297.1	381.6	151.9	153.6	1,790.2	7,064.8	12,839.3
Net Income	194.0	13.1	5.2	2.2	52.6	205.0	472.1
Net Book Value of Assets	1,976.3	110.6	82.2	61.7	678.7	2,557.8	5,467.3
Capex	933.4	32.0	19.8	6.1	121.8	758.8	1,871.8
OM&A	547.1	20.2	21.8	21.6	180.9	559.0	1,350.6
Avg. Rate Base	5,562.8	309.6	37.4	4.7	37.4	426.6	182.7
Rate Base	5,562.8	309.6	186.8	83.9	1,346.1	6,398.9	13,888.1
Monthly LDC Revenue / Customer ($)	49.8	22.7	30.6	25.8	26.2	26.3	26.7
Ratios							
OMA per km of Line ($/km)	4,524	7,150	6,751	11,456	8,944	11,568	6,842
Customers per km^2 of Svc Area	2	499	4	52	94	356	7
Customers per km of Line	10	48	20	36	39	52	24

Figure 1: Snap Shot of Ontario's LDCs

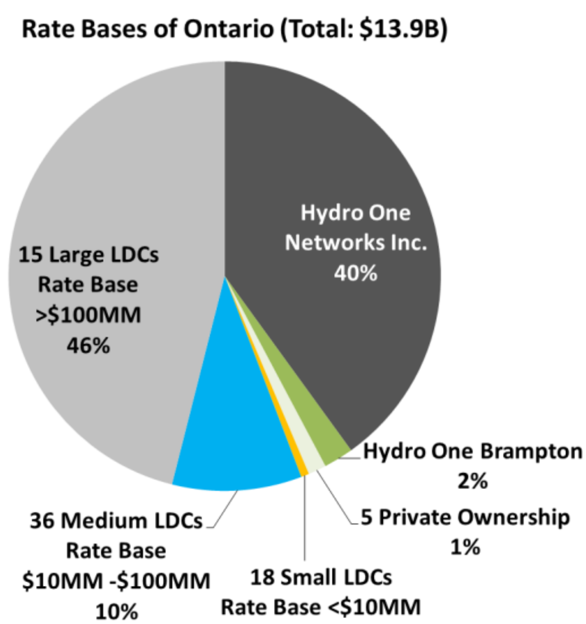


Figure 2: Rate Bases of Ontario

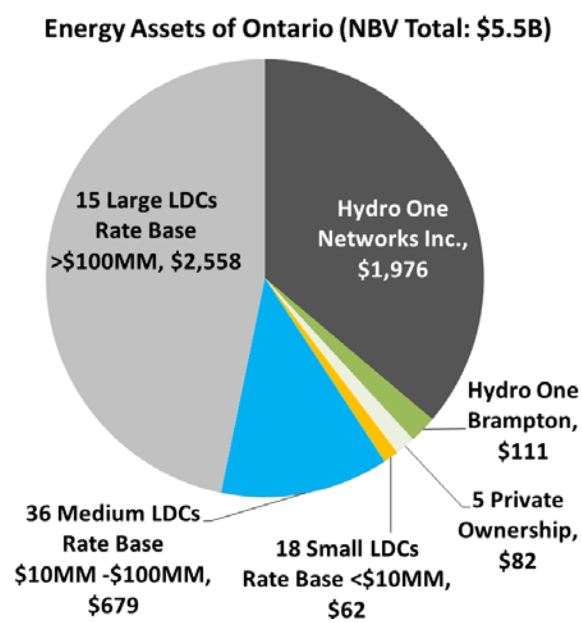


Figure 3: Energy Assets of Ontario

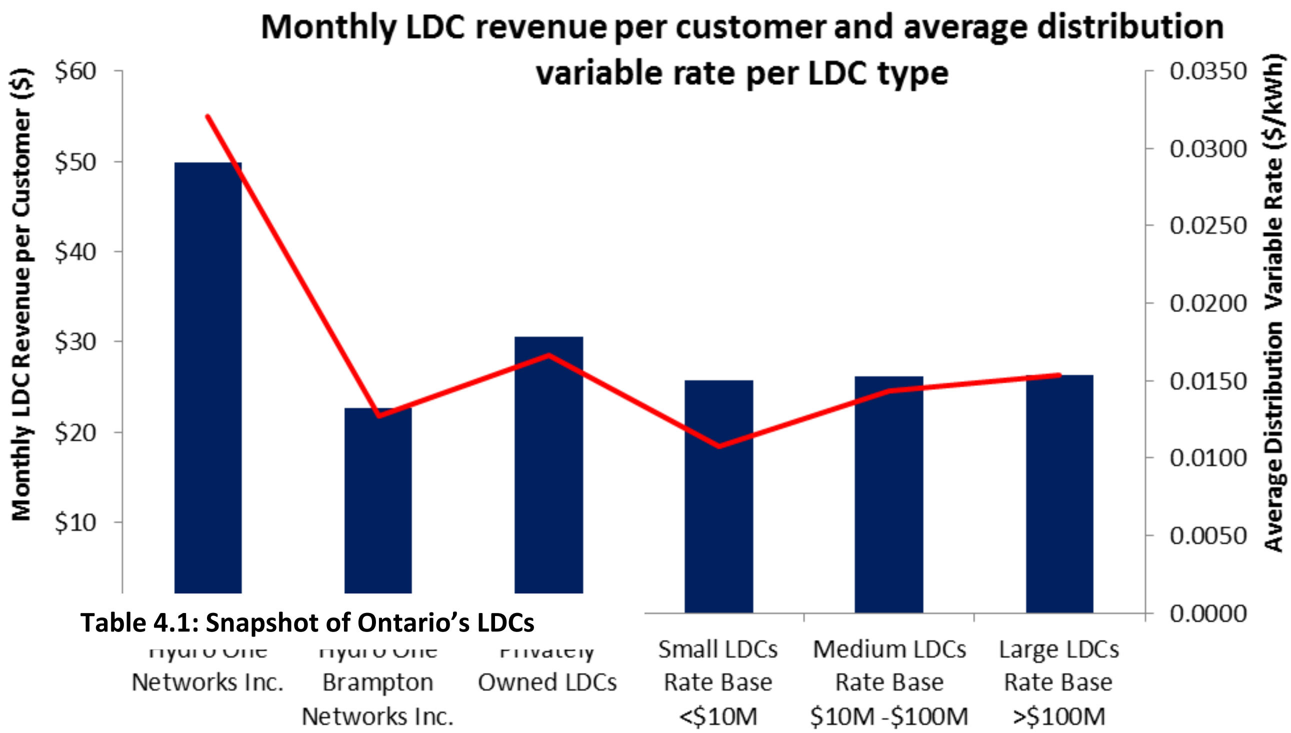
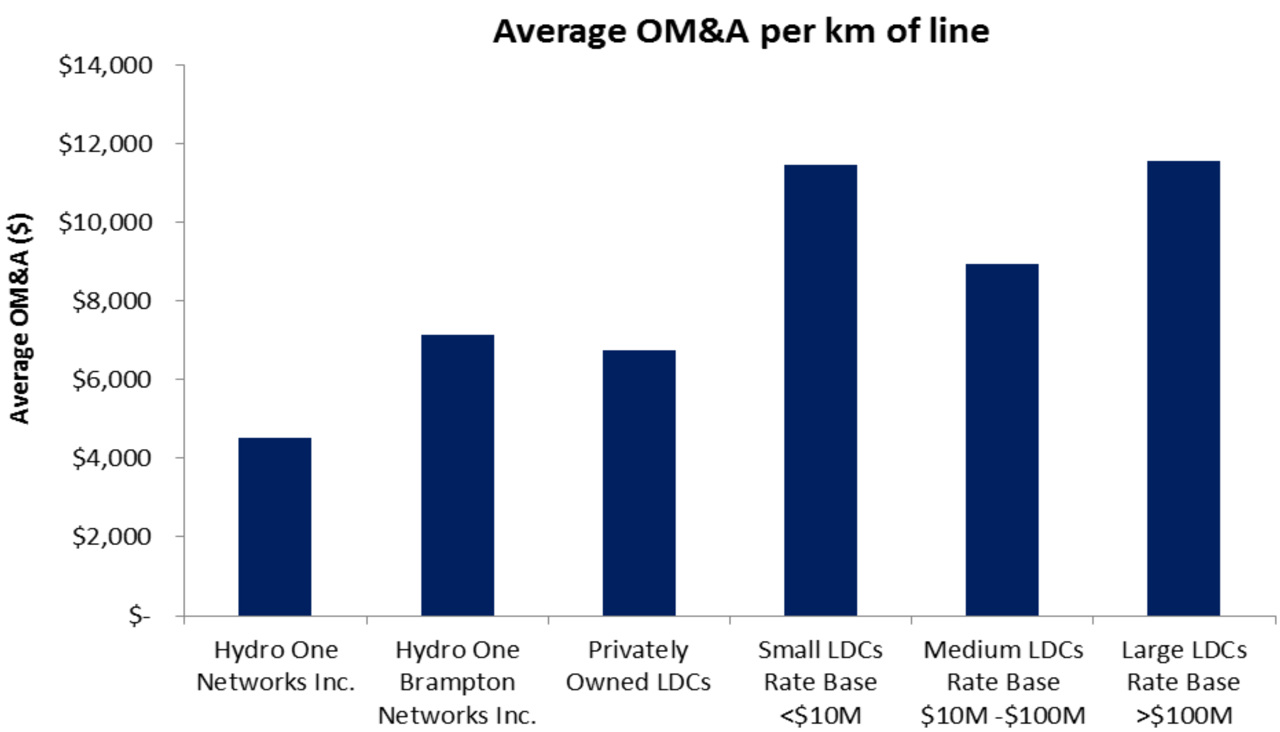
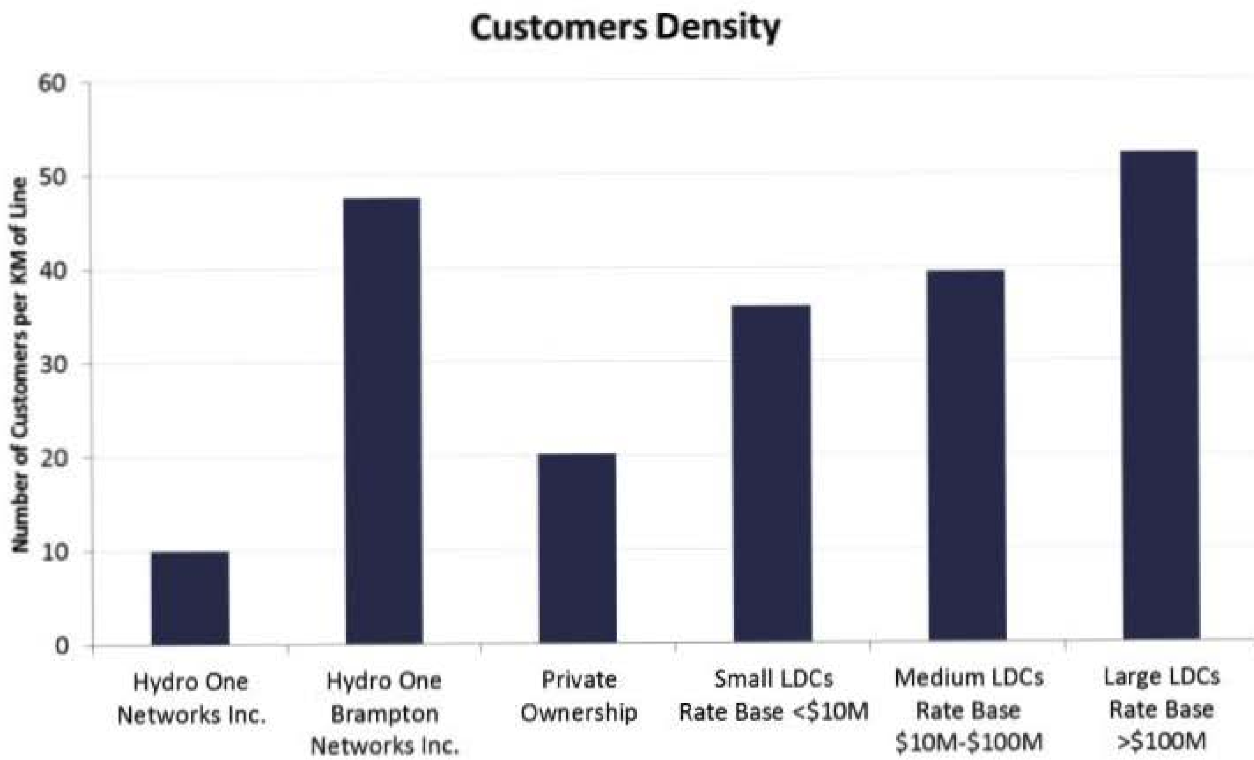


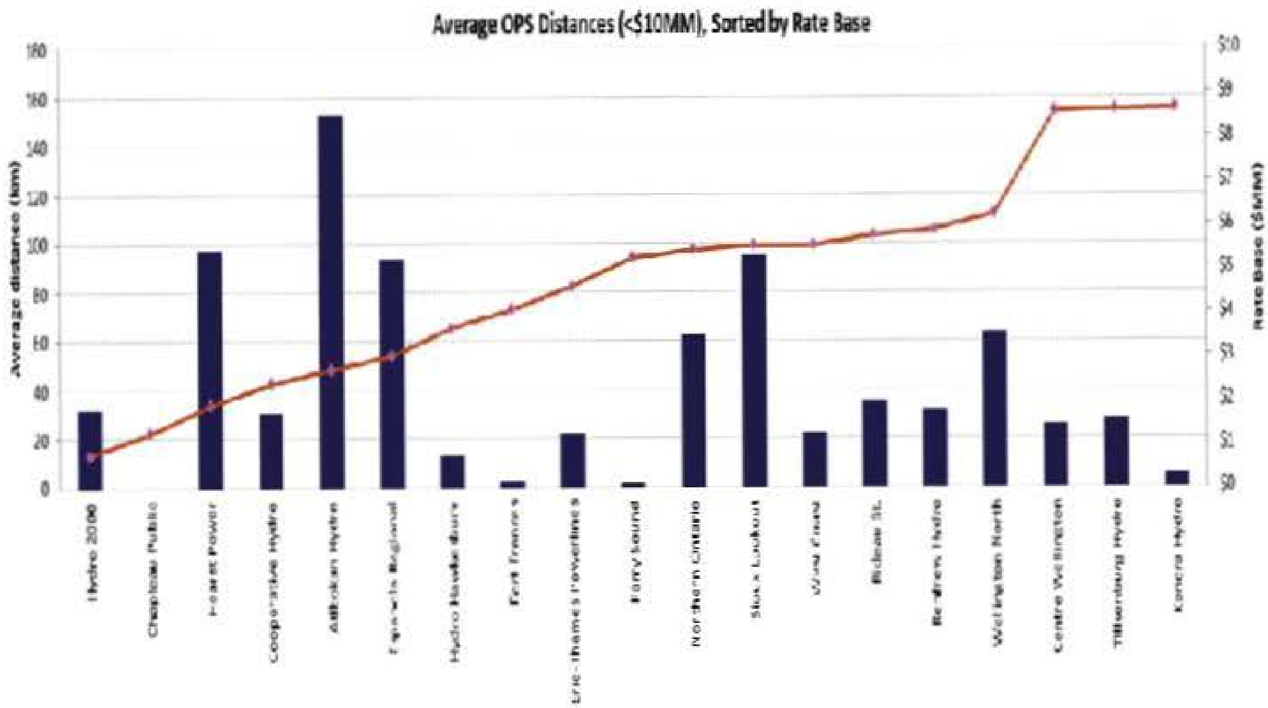
Table 4.1: Snapshot of Ontario's LDCs

Figure 4: Monthly LDC revenue per customer and average distribution variable rate per LDC type

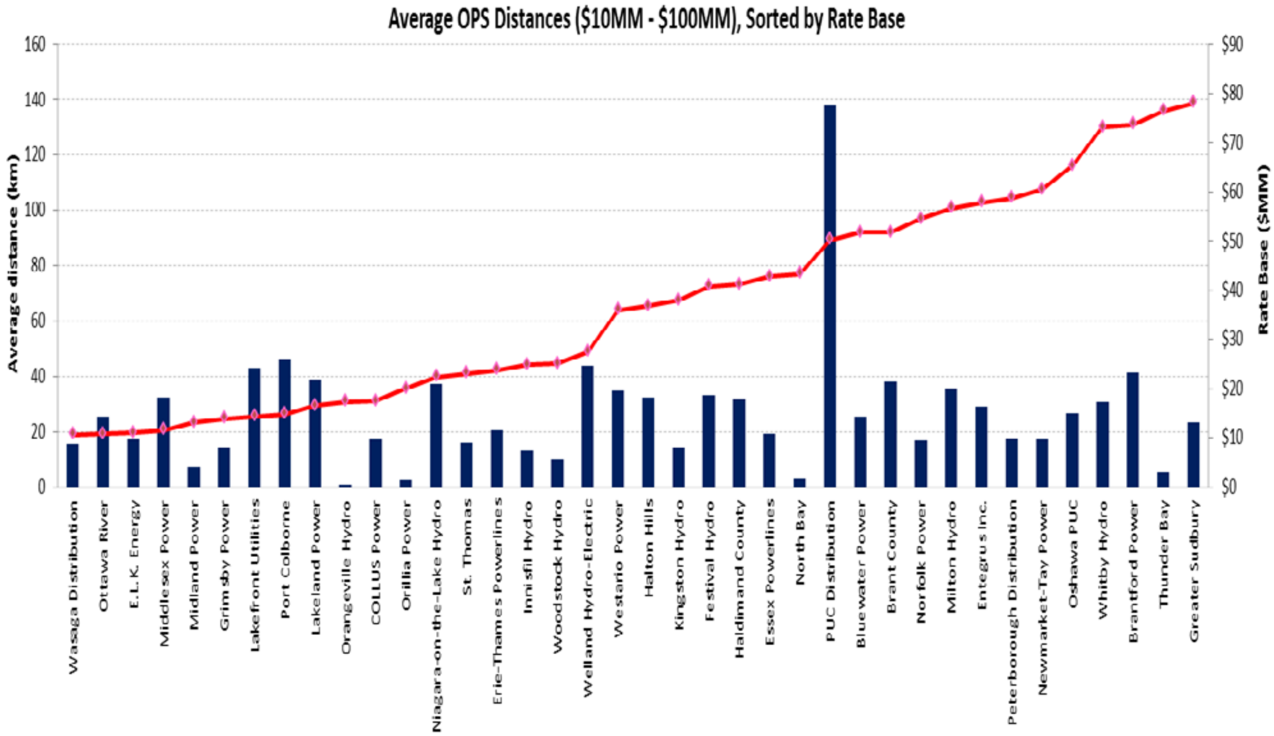




Customers Density
Number of Customers per KM of Line
60
50
40
30
20
10
0
Hydro One Networks Inc.
Hydro One Brampton Networks Inc.
Private Ownership
Small LDCs Rate Base <$10M
Medium LDCs Rate Base $10M-$100M
Large LDCs Rate Base >$100M

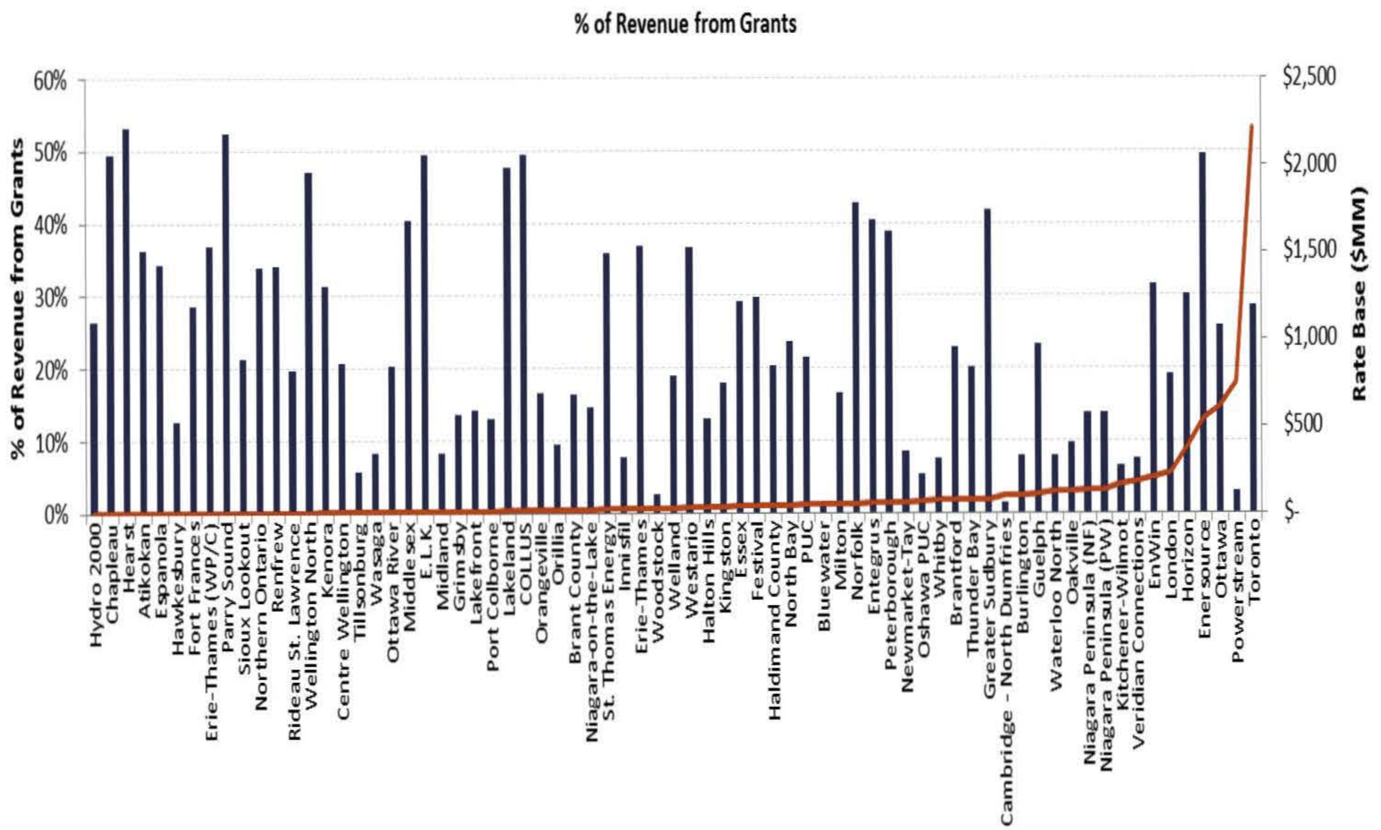


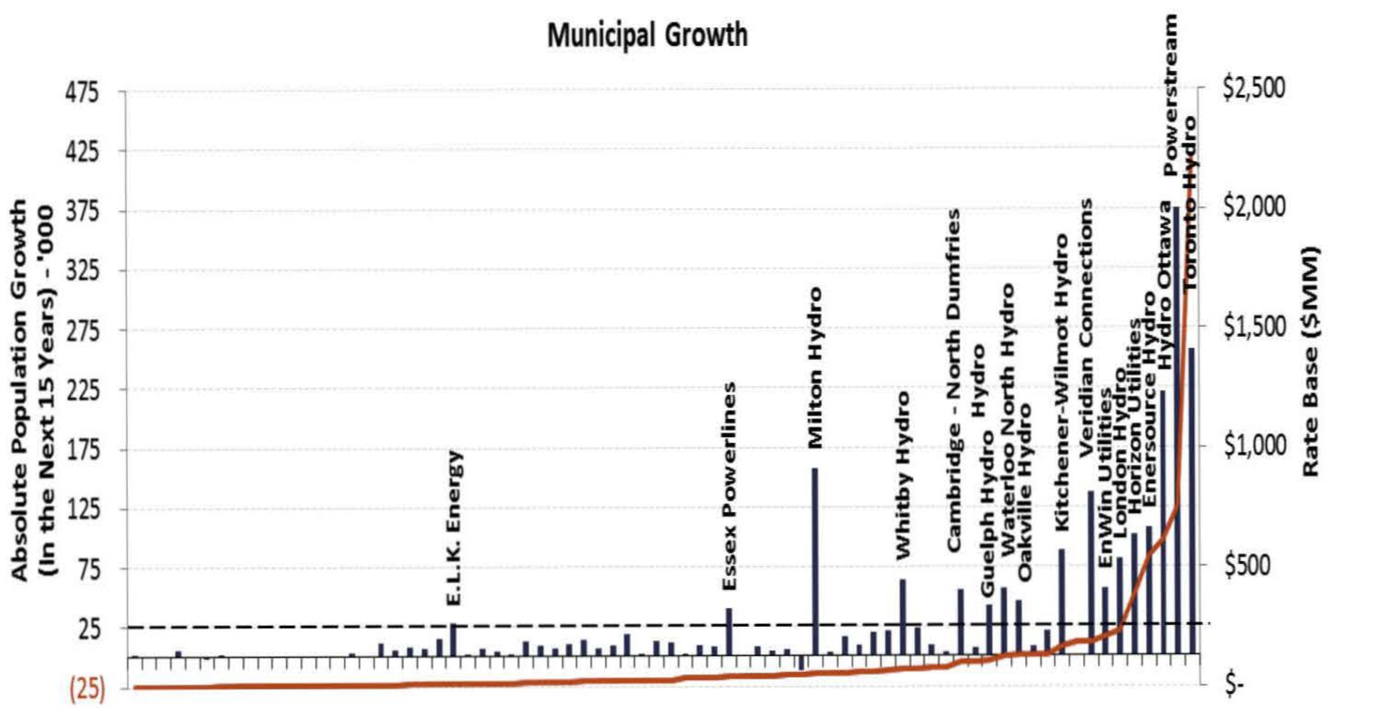
Average OPS Distances (<$10MM), Sorted by Rate Base
Average distance (km)
Rate Base ($MM)
Hydro 2000
Chapleau Public
Hearst Power
Cooperative Hydro
Atikokan Hydro
Hydro Hawkesbury
Fort Frances
Erie-Thames Powerlines
Parry Sound
Northern Ontario
Sioux Lookout
Renfrew Hydro
Wellington North
Centre Wellington
Tillsonburg Hydro
Kenora Hydro



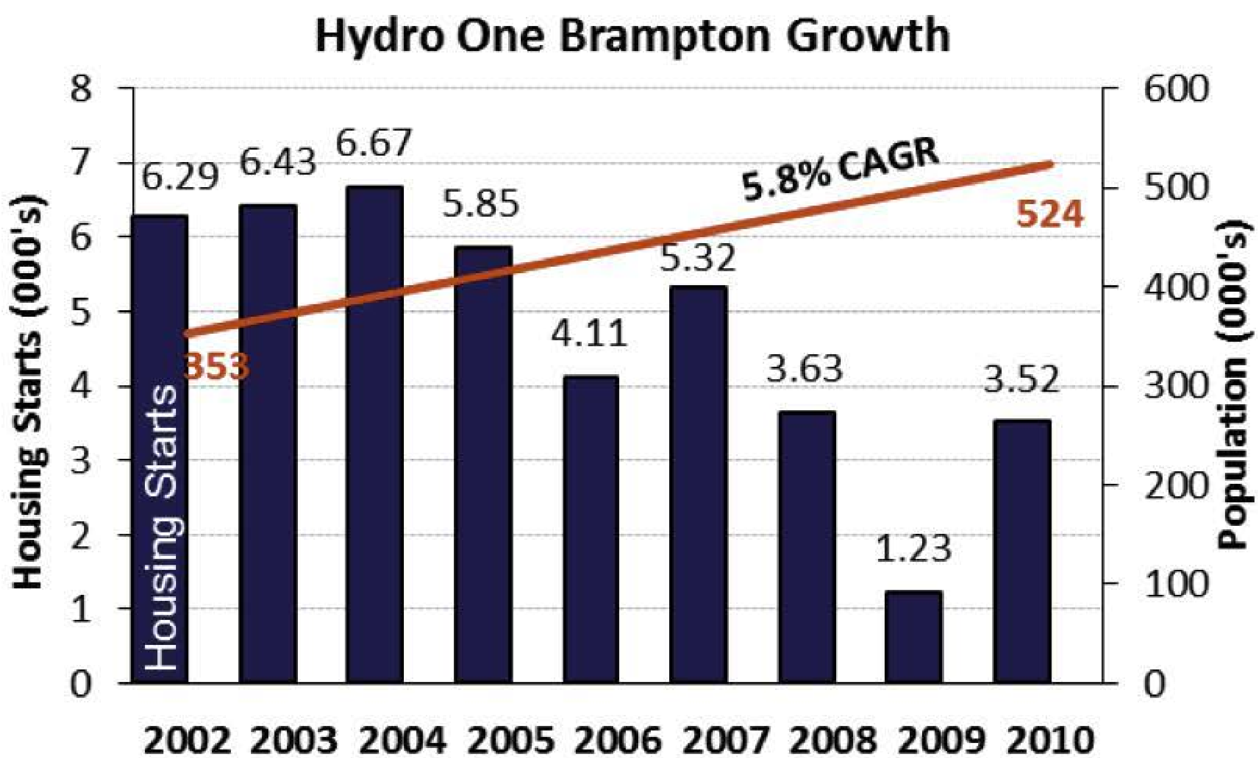
Average OPS Distances ($10MM - $100MM), Sorted by Rate Base
Average distance (km)
Rate Base ($MM)
160
140
120
100
80
60
40
20
0
$90
$80
$70
$60
$50
$40
$30
$20
$10
$0
Wasaga Distribution
Ottawa River
E.L.K. Energy
Middlesex Power
Midland Power
Grimsby Power
Lakefront Utilities
Port Colborne
Lakeland Power
Orangeville Hydro
COLLUS Power
Orillia Power
Niagara-on-the-Lake Hydro
St. Thomas
Erie-Thames Powerlines
Innisfil Hydro
Woodstock Hydro
Welland Hydro-Electric
Westario Power
Halton Hills
Kingston Hydro
Festival Hydro
Haldimand County
Essex Powerlines
North Bay
PUC Distribution
Bluewater Power
Brant County
Norfolk Power
Milton Hydro
Entegrus Inc.
Peterborough Distribution
Newmarket-Tay Power
Oshawa PUC
Whitby Hydro
Brantford Power
Thunder Bay
Greater Sudbury

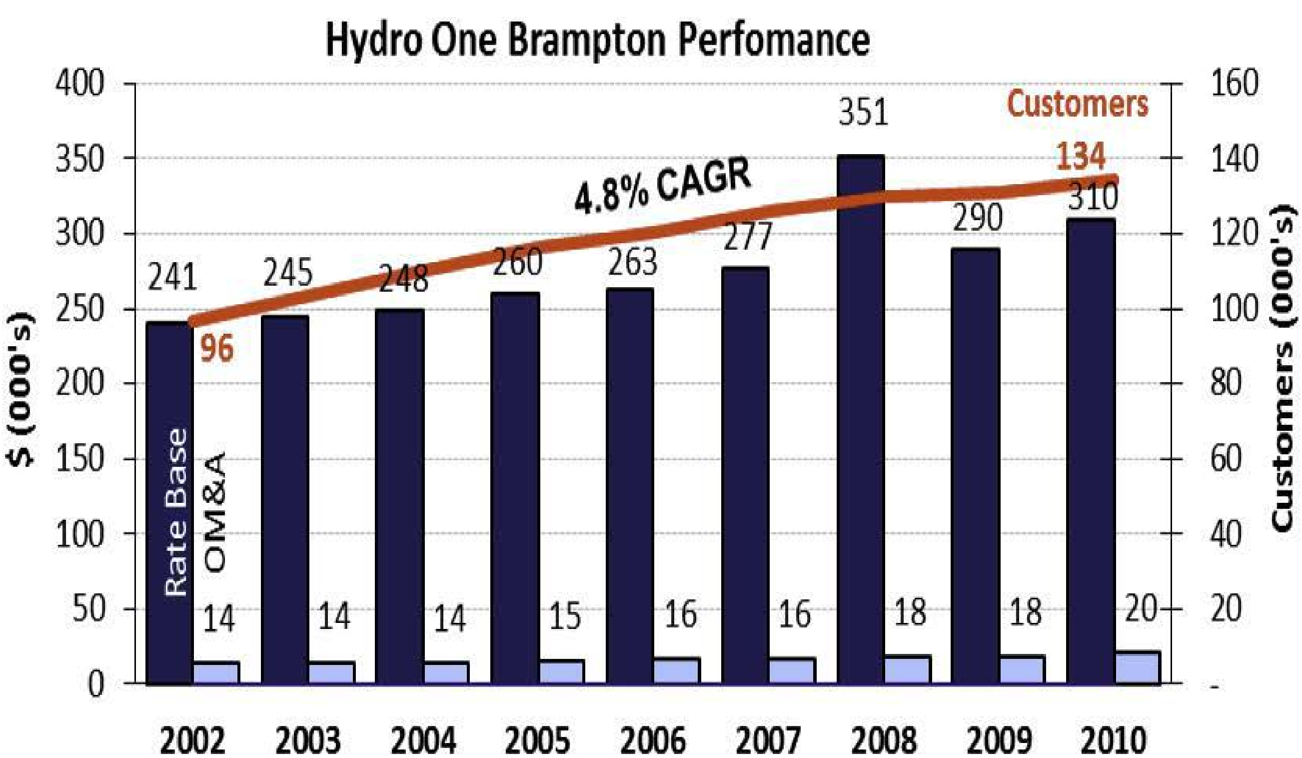
Municipal Information





Hydro One Brampton





ACQUISTION SAVINGS FROM PAST EXPERIENCE

One-time

- Estimated one-time OM&A savings (forecast MEU operations versus HONI's incremental cost) = $170M NPV[1]
  - o Eliminating duplication
  - o Rationalizing service workforce and of administrative functions
  - o Key value drivers: buildings – 30%; staff – 30%; B&C – 10%; general administration – 9%; other/miscellaneous – 21%
- $30M NPV of additional capex savings before system optimization benefits[2]

Ongoing[3]

- Most LDCs are within reach of HONI facilities
  - o 85 of 88 MEUs' facilities (net) not required[4]
- 11% lower annual distribution-related OM&A costs due to a better use of existing assets
- O&M unit cost/customer reduced from $200 to $178 (-11%)
- Service optimization permits better work planning, and more wrench-time and less travel-time from staff

PAST ACQUISTION PROGRAM

- **Acquired 89 LDCs for $500M (excluding excess cash)**
  - o Total rate base – $431M; Total price paid – $503M; Premium – 17%
- **Acquired Staff**
  - o 202 of 300 hired; 121 required, 81 surplus
- **Impact on customer/staff**
  - o HONI pre-acquisition – 198; Combined – 226 (+14%)

	HONI Before	**MEU Acquisitions**	**HONI After**	**% Change**
Customers	957,000	245,000	1,202,000	26%
PP&E (NFA)	$2,593M	$397M	$2,990M	15%
Staff	4,815	392	5,207	8%
Customers/Staff	198	625	230	-16%
OMA/Customer	200	49	178	-11%

[1] Net of one-time integration costs and industry transition and restructuring costs incurred by MEU; excluding Brampton

[2] Expect to achieve a 15% cost savings in capex

[3] Incremental costs do not include corporate overheads, assumes sufficient infrastructure capacity to take on more business, and assumes additional capacity to do more work

[4] 3 locations added to HONI to service 88 acquisitions, including Carleton Place, Clarence Rockland, and Deep River; 14 MEU acquisitions resulted in duplicate facilities

SYNERGIES ACHIEVED FROM ROUND ONE

- Weighted average (by customer) synergies were ~32%
    - CF&S – 4%
    - Services – 7%
    - Back-Office – 11%
    - Customer Care – 10%

- Additional savings from billing, DSM, and Smart Meter synergies

School Energy Coalition (SEC) INTERROGATORY #5 List 1

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

Interrogatory

[A-13-2/p.107/ ss.11.2.8]
Has the Applicant considered the "recommendations and implications of the Report of the Commission on the Reform of Ontario's Public Services ("Drummond Report, 2012)"? If so, please provide HONI's response to the Drummond Report.

Response

The Drummond Report on public-service reform provided recommendations to eliminate the $16-billion Ontario deficit within five years. Since this report was prepared for the Ontario government, Hydro One did not prepare a response to the recommendations.

School Energy Coalition (SEC) INTERROGATORY #6 List 1

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

Interrogatory

[A-17-2/p.2]
Please clarify what 'associated working group" the Applicant is talking part in regarding the Staff Discussion Paper on "*Defining Measuring Performance of Electricity Transmitters & Distributors EB-2010-0379*".

Response

Subsequent to issuing the discussion paper, the OEB hosted two stakeholder conferences, a series of executive roundtable meetings, and an information session in 2011 and 2012 to invite input into the discussion papers. Hydro One participated in all sessions:

- February 2, 2011 – Stakeholder Conference at the OEB office
- December 8 - 9, 2011 – Information Session at the OEB office
- February and March 2012 – Executive Roundtable Meetings held by the OEB Chair
- March 28 - 30, 2012 – Stakeholder Conference at the OEB office

Consumers Council of Canada (CCC) INTERROGATORY #1 List 1

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

Interrogatory

Please provide the following:

- All of the correspondence between HONI and its shareholder regarding the 2013/2014 Transmission Rate Application;
- All presentations or reports provide to the HONI Board of Directors related to the 2013/2014 rate application.

Response

Hydro One has filed the attached Interrogatory request respecting shareholder correspondence regarding the 2013/2014 Transmission Rate Application pursuant to the Board's Practice Direction on Confidential Filing. Hydro One's Disclosure Policy, as well as applicable securities legislation, prohibits the release of non-public, financial information on a selective basis to individuals or groups of individuals. In addition the material requested includes information with respect to matters that are outside the scope of this proceeding. Hydro One is prepared to share a copy of the confidential filing with intervenors who sign the Board's confidential undertaking form. A redacted version of the requested information is included as Attachment 3.

The reports to the Hydro One Board of Directors related to the 2013/2014 rate application are included as Attachments 1 and 2.

6c

Hydro One Inc.
Submission to the Regulatory and Public Policy Committee of the Board of Directors

hydro One

Date: February 8, 2012

Subject: Rate Application Status Update

Submitted by:

Susan Frank

Susan Frank
Vice President and
Chief Regulatory Officer

REASON FOR REPORT

This Report is submitted to the Regulatory and Public Policy Committee of the Hydro One Board of Directors to inform the Committee about Hydro One's proposed strategy considerations for the filing of transmission and distribution rate applications with the Ontario Energy Board (the OEB), given the OEB's recent Toronto Hydro distribution decision and anticipated favourable decision for the adoption of US GAAP by Hydro One Distribution.

KEY HIGHLIGHTS

- Transmission Cost-of-Service (COS) Rate Application for 2013 and 2014 rates should be filed in April 2012.
- Hydro One should file a Distribution Incentive Rate Mechanism (IRM) Rate Application for the 2013 test year including an Incremental Capital Module, in July of 2012, and file a similar IRM application in July of 2013 for the 2014 test year.
- Hydro One will likely file a Combined Transmission and Distribution application in April of 2014 for the 2015 and 2016 test years.

BACKGROUND

At the last RPPC meeting held on November 8, 2011, this Committee reviewed four potential filing alternatives. Management indicated that the option selected would be influenced by the OEB's Transmission US GAAP Decision and its Toronto Hydro early rebasing application Decision. The current business plan assumes a combined Transmission and Distribution COS application filed in April of 2012 to establish distribution and transmission rates for the 2013 and 2014 test years.

The OEB denied Toronto Hydro's COS application and invited them to re-submit an IRM filing with an Incremental Capital Module (ICM) (refer to Agenda Item 6b).

Hydro One filed its last Distribution COS rate filing in 2009 and received approval for 2010 and 2011 rates. While Hydro One has received approval for the use of US GAAP for Transmission, the Distribution US GAAP review is still ongoing with a decision not expected until the end of March 2012. As part of the US GAAP Distribution application, Hydro One requested no change to the approved 2011 rates, at this time, to ensure that the Distribution US GAAP decision not be confused with rate implications for 2012.

Hydro One Transmission has OEB-approved rates for 2012 which reflect the OEB's acceptance of US GAAP for Transmission and the approval from Hydro One's 2010 Transmission Rate Application.

Given the continuing demands to invest in our aging transmission system and the corresponding need for higher transmission rates, Hydro One continues to recommend the filing of a COS Rate Application for Transmission 2013 and 2014 rates in April 2012. This application will include both the compensation and productivity benchmarking studies directed by the OEB (Refer to Agenda Item 8).

In 2010, the OEB directed Hydro One to carry out a study of the relationship between customer density and distribution service costs. The study confirmed that as customer density decreases, the cost to serve the same number of customers increases (refer to Agenda Item 7). It is expected that density-related changes to cost allocation, as per the study, could result in a reduction of UR (urban) rates by about 14% and a compensating increase in R2 (rural) rates of 2%.

FILING OPTIONS

The recent Toronto Hydro decision and the delay to the Distribution US GAAP decision has led Hydro One to consider four distribution filing options including:

1. File a Combined Distribution and Transmission COS application for 2013 and 2014, as per the approved business plan, by June 2012
2. Do not file a distribution application for the 2012-2014 period.
3. File annual IRM applications for 2012, 2013 and 2014 test years. An IRM application for 2012 distribution rates would be filed in May 2012 following approval of the Distribution US GAAP application. An additional IRM filing would be submitted for 2013 rates in December 2012 and in July 2013 for 2014 Distribution rates.
4. File an IRM application for 2013 distribution rates including an ICM for discrete, non-discretionary capital projects, in July 2012 and an IRM filing in 2013 for 2014 rates with an ICM. No application would be filed for 2012 rates. The inclusion of a Z- factor adjustment for pension costs is still under consideration. The OEB-directed Density Study, while not normally part of an IRM filing might be filed to initiate the correction needed to urban rates.

After review with the Executive Committee on January 19, 2012, options 2 and 3 were dismissed. Option 2 with no change to rates over a three year period would require cuts to the work program that are expected to have a negative impact on system performance and require a large increase in rates in 2015. While option 3, with three IRM filings in a 2-year period for 2012, 2013 and 2014 is possible, this option was dismissed as the incremental effort required would detract from the Transmission COS proceeding.

The two remaining options are summarized in the tables below. The timelines, effort, rate impacts, net income, risks and opportunities for each option are provided in the attached Scenarios.

Net Income

Option ($M)	2012	2013	2014	2015	Cumulative
Option 1 Business Plan	237	264	298	317	**1116**
Option 4 2013/14 IRM	257	269	255	309	**1090**

Total Bill Impact for Distribution and Transmission Applications

(%)	2012	2013	2014	2015	Cumulative
Option 1 Business Plan	0.6	0.6	3.1	4.2	**8.5**
Option 4 2013/14 IRM	0.5	2.1	1.6	3.8	**8.0**

There is little difference between the two options with respect to Net Income or Rates. However the risks of a successful filing are quite different.

Risks

Option 1 Combined COS Application (Business Plan)	Option 4 2013 and 2014 IRM Applications
• OEB rejection of the distribution component of the joint application for failure to meet the threshold test is highly probable given the Toronto Hydro decision. The arguments for hardship for Hydro One are much inferior to Toronto Hydro's situation. • Hydro One would have to absorb all internal, OEB and intervenor costs of the distribution portion of the application when the OEB denies the Dx COS filing. • Dealing with the hearing to consider if a Distribution COS application should be accepted would delay the Transmission application. • If the Distribution COS application was accepted by the OEB, the added complexity of a joint hearing would likely mean that rates for both transmission and distribution would not be effective until March 1, 2012.	• The ICM application requires annual filings which do not provide the same ability to plan expenditures that a multi- year COS application provides. • Adding elements to the IRM filing such as an ICM application, particularly related to the new CIS, will likely require an oral hearing. • Seeking recovery for Z factors, such as the pension costs, would add to the likelihood of an oral hearing • May reject a review of the density study and any proposed rate adjustments, thereby continuing rate inequities until the next COS application.

Ranking of Options

	Chance of OEB Approval	FTEs Required for Dx (Person Weeks)	External Costs*
Option 1 Business Plan	Low	525	$800,000
Option 4 2013/14 IRM	High	250	$350,000

* External Costs include intervenor , OEB, consultant and legal costs.

RECOMMENDATION

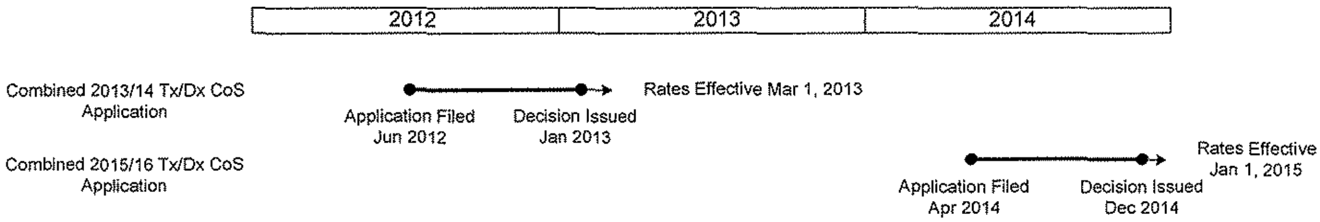
Given the recent Toronto Hydro Decision and a detailed analysis of the OEB's findings and applicability to Hydro One, it is recommended that Hydro One proceed with Option 4 and the filing of a stand-alone transmission application for the 2013 and 2014 test years in April 2012. Under Option 4, Hydro One would file a distribution IRM application in July of 2012 for 2013 rates and in July 2013 for 2014 rates. In April of 2014, we would likely file a combined distribution and transmission COS application for the 2015 and 2016 test years. The 2015 test year would be the distribution rebasing year after three years under IRM.

In addition to the lower risk, less effort with no material difference in net income or rates, Option 4 also allows for a concentration of resources on the Transmission proceeding during 2012.

Finally, IRM normally does not allow cost allocation or rate design changes. However, due to the wide gap between current rates and the cost-based rates identified in the density study, Hydro One could apply for a phased implementation of the study recommendations. For example, if the approved IRM rate was 3%, Hydro One might suggest that the R2 customer rates go up by 3.5% and the UR customer rates remain the same. In addition to being more reflective of the Density Study directions, these adjustments would assist with distribution rationalization.

Scenario 1 – Combined 2013/2014 Distribution and Transmission COS Application

Timeline



Effort

Total Incremental FTEs required for Distribution – 525 person weeks

Incremental External Costs - $800,000

Rates Impact (%)

	2012	2013	2014	2015
Dx Rate Increase	0.0	0.2	7.0	10.5
Total Bill increase – Dx only	0.0	0.1	2.3	3.5
Total Bill increase – Dx and Tx	0.6	0.6	3.1	4.2

Net Income Impact ($M)

	2012	2013	2014	2015
Net Income – Business Plan	237	264	298	317

Risks and Opportunities

Risks:

- Following the Toronto Hydro Decision, the OEB would likely reject the Distribution COS since Distribution should be on a 3-year IRM as we do not meet the threshold for rebasing.
- Will not be able to file an application until June, 2012 and will not receive an OEB Decision in time for January 1, 2013 Transmission and Distribution rates. Would expect to receive an OEB Decision in time for new rates to be effective on March 1, 2013 which would delay the Transmission rate implementation by 3 months.

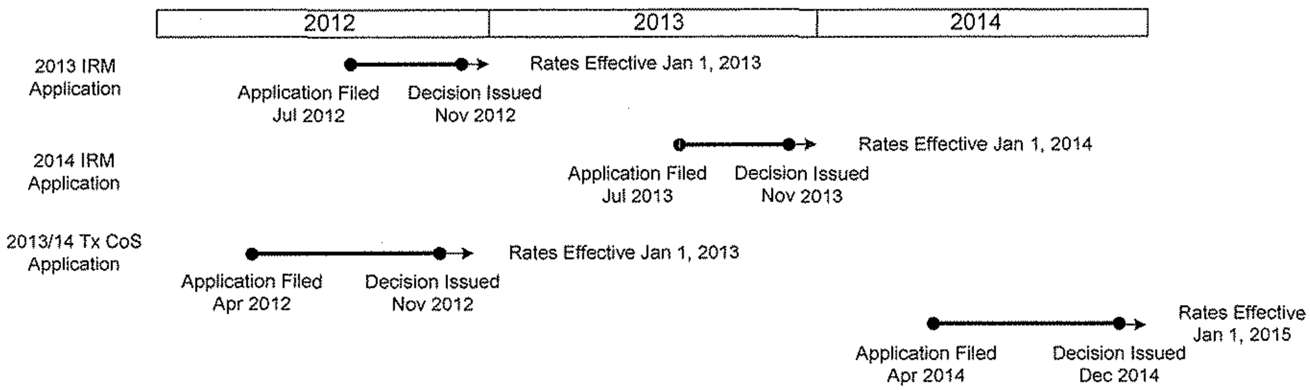
Opportunities:

- This option would result in approved rates for 2013 & 2014 for Transmission and Distribution, which would likely commit Hydro One to filing combined applications going forward.

Recommendation: This option is not recommended.

Scenario 4 – Transmission COS for 2013/2014 and Distribution IRM for Only 2013 and 2014

Timeline



Effort

Total Incremental FTEs required for Distribution – 250 person weeks

Incremental External Costs – $350,000

Rates Impact (%)

	2012	2013	2014	2015
Dx Rate Increase	-0.2	4.9	2.5	9.3
Total Bill increase - Dx only	-0.1	1.6	0.8	3.1
Total Bill increase - Dx and Tx	0.5	2.1	1.6	3.8

Net Income Impact ($M)

	2012	2013	2014	2015
Net Income – Business Plan	237	264	298	317
Net Income – Scenario 4	257	269	255	309
Net Income Delta	20	5	(43)	(8)

Risks and Opportunities

Risks:

- It is possible that the OEB will reject all or part of the ICM requests.

Opportunities:

- An ICM could be used in the 2013 IRM to recover the CIS costs.
- This option requires less resources than option 1.
- The increase in rates in 2013 and 2014 reduces the large rate increase in 2015.

Recommendation: This is the recommended option.

Hydro One Inc.
Submission to the Board of Directors

hydroOne

Date: April 5, 2012

Subject: Hydro One Application for the 2013 – 2014 Transmission Rates

Submitted by:

Sandy Struthers
Executive Vice President and
Chief Financial Officer

Approved for Submission to the Board by:

Laura Formusa
President and Chief Executive Officer

RECOMMENDATION

THAT the Board of Directors of Hydro One Inc. approve Hydro One's 2013 – 2014 Transmission Revenue Requirement and Rate Application for submission to the Ontario Energy Board in mid-April 2012.

KEY HIGHLIGHTS

- The Transmission Business Revenue Requirement for 2013 and 2014 is $1,467M and $1,561M respectively, consistent with the 2012 – 2016 Budget and Business Plan update for which approval is also being sought from the Board of Directors today.
- The resulting increase in transmission rates is 0.8% in 2013 and 9.2% in 2014. This represents an estimated increase on total customer bills of 0.05% in 2013 and 0.7% in 2014.
- The major factors contributing to the rate increases are the addition of in-service transmission investments in the asset rate base for the expansion of our infrastructure; maintenance costs to sustain the current system; as well as changes in the load forecast.
- It is anticipated that the major focus of the Ontario Energy Board hearing will be on the growing capital budget, overall compensation levels and productivity.

This Board Memorandum was reviewed and approved for submission to the Board of Directors of Hydro One Inc. by the Regulatory and Public Policy Committee at its meeting on April 4, 2012.

EXECUTIVE SUMMARY

1. Strategic Significance

Hydro One plans to file an application, following Hydro One Board approval with the Ontario Energy Board in April 2012, for new transmission rates effective January 1, 2013 and January 1, 2014. The rates requested are consistent with the Company's strategy of building and maintaining a reliable, cost effective transmission system and supporting the facilitation of the Government initiatives. The Regulatory and Environment Committee has guided the development of the 2013 – 2014 Transmission Rate Application since November 2011.

This Application is consistent with the Business Plan update approved by the Board today. The Business Plan approved by the Board in November 2011 included a rate increase of 7.0% for 2013 and 10.2% for 2014. The reduction to 0.8% in 2013 in the update is the result of a lower cost of capital forecast, an adjusted increase in the load forecast and increases in the non-tariff revenue forecast. The level of capital and OM&A work remains unchanged from the November 2011 approved Business Plan. The reduction in 2014 is largely due to a lower cost of capital forecast.

2. Purpose

Hydro One requires Board approval to file a Transmission Rate Application with the OEB seeking a revenue requirement for 2013 of $1,467M and $1,561M for 2014. The revenue requirement is composed of annual OM&A as well as the carrying costs for assets in-service including the depreciation of the assets and cost of capital (interest payments and return on equity). The requested level of funding balances system requirements and concern for customer rate increases given customer sensitivities. Table 1 provides a summary of the key financial metrics which will be requested in the Application.

Table 1

Revenue Requirement (M$)

	OEB Approved 2012	2013	2014
OM&A	427	452	460
Carrying Costs of Assets			
Depreciation	333	349	376
Cost of Capital	607	621	670
Income Tax	51	45	55
Total Base Revenue Requirement	**1,418**	**1,467**	**1,561**
Capital Expenditures	**981**	**1,070**	**1,089**
Rate Base	**8,774**	**9,460**	**10,073**
ROE %	**9.42**	**9.16**	**9.44**
Net Income	**384**	**390**	**433**

The details of the contributing factors, as updated, are shown in Table 2

Table 2

MAJOR CONTRIBUTING FACTORS	CHANGE IN TX RATES (%) 2013	2014
Growth in Assets (Rate Base)	4.1	5.7
Increase in OM&A	1.6	0.5
System Requirements	**5.7**	**6.2**
Change in Cost of Capital	(2.3)	0.6
Change in Load Forecast	(0.4)	2.3
Riders & Export Credit	(2.2)	0.1
Total	**0.8**	**9.2**

The annual rate increases are mainly attributed to the growth in the asset base and OMA increases to support the ongoing business and the facilitation of distributed generation connections. In 2013 the requested rate increase is largely offset by a downward adjustment in the cost of capital, an increase in the load forecast and refunds to customers of increased miscellaneous and export transmission revenues. In 2014, the lower load forecast is related to achieving the CDM targets.

Stakeholder sessions with the intervenor community, industry associations, local distribution companies, end-use transmission customers and other transmitters were held in 2011 to seek input on the design of the compensation and productivity studies and upon completion, to provide them with a summary of the study findings.

It is anticipated that stakeholders will focus on the proposed level of capital and OM&A spending and the ability of Hydro One to complete this work. Compensation levels and the reflection of productivity offsets will also be explored.

After full and lengthy discussions with the Ministries of Energy and Finance, the shareholder has reached an understanding of Hydro One's need to file the transmission rate application and has no further questions.

4. Risk Analysis

- Hydro One is requesting a $0.7 billion increase in rate base for 2013 and an additional $0.6 billion increase for 2014. Anticipated intervenor concerns regarding the appropriateness of this level of work especially the increase in sustainment capital work in the test years, will be addressed with extensive evidence on capital projects and programs. Intervenors may challenge our ability to complete our capital work programs in 2013 and 2014 and will require assurance regarding our in-service addition forecasts. Our evidence will reinforce the fact that the requested increases in rates are largely the result of previous OEB approved capital programs which come into service and into rate base in the test years (e.g. full year impact of the Bruce to Milton project completed in 2012, rebuild of Hearn TS and the Mid-Town Toronto reinforcement project) and government direction on the need to expand the transmission system to accommodate renewable generation. The evidence will also demonstrate our enhanced capability to execute work through strategic sourcing initiatives and the practice of awarding turn-key projects to third party contractors.

- The evidence will emphasize initiatives undertaken by the Company to improve productivity and efficiency thus offsetting forecast compensation increases and thereby minimizing rate impacts to customers. This evidence, coupled with the results of the Mercer Study, which show Hydro One has made progress in bringing compensation levels closer to its utility peers, will be used to alleviate OEB concerns from the last transmission filing with respect to overall compensation levels at Hydro One.

- The final Cost of Capital established for the test years will be established by the OEB in November of 2012 and 2013 and may differ from what is reflected in the current outlook.

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James Arnett
Chair

hydroOne

January 4, 2012

The Honourable Chris Bentley
Minister of Energy
Hearst Block, 900 Bay Street, 4th Floor
Toronto, ON M7A 2E1

The Honourable Dwight Duncan
Minister of Finance
Frost Building South
7 Queen's Park Crescent, 7th Floor
Toronto, ON M7A 1Y7

Dear Minister Bentley and Minister Duncan:

2012 Budget and 2013/2014 Outlook

In accordance with the Memorandum of Agreement of March 27, 2008 with the Province of Ontario, as shareholder, please find the 2012 Budget and 2013/2014 Outlook with which we hope you will concur. Our Board of Directors approved the 2012 budget and 2013/2014 financial outlook on November 10, 2011.

The 2012 Budget and 2013/2014 Outlook have been discussed with the Assistant Deputy Ministers in the Ministry of Energy and Ministry of Finance and a draft copy of this document was provided to Ministry of Finance and Ministry of Energy Staff.

Recognizing that the Company must obtain productivity in its operations and still deliver the required work program, OM&A costs over the period from 2012 to 2014 have been contained to an average annual increase of less than 1.5%. Included in the 2012 Budget and 2013/2014 Outlook are initiatives which result in some $280 million of operations and capital savings that the Company would otherwise have sought to recover through higher electricity rates. Mindful of its customers, the Company will not seek an increase in its existing electricity distribution rates for 2012 and has sought and recently received approval from the Ontario Energy Board for a 15% reduction in its already-approved electricity transmission rates for 2012.

I trust you will find the document in order and provide your concurrence.

Yours truly,

James Arnett

Encl.

give copy to Sandy Stratton

c: Laura Formusa
David Lindsay
Steve Orsini

hydro One

November 2011

HYDRO ONE INC.

2012 BUDGET AND 2013/2014 OUTLOOK

EXECUTIVE SUMMARY

The Budget establishes the level of operations, maintenance and administration ("OM&A") and capital expenditures over the planning period, as well as net income and critical financial metrics. The Budget reflects the Company's mandate, vision, values, and drives towards meeting the strategic objectives. The Budget also considers the Corporate Risk Profile. A long-term investment plan has been developed for transmission and distribution that includes the investments required to support distributed generation ("DG"). End-of-life ("EOL") assets are driving the need for a ramp-up in investments over the longer term. This trend has been tempered with program and cost reductions to address customer rate concerns in the shorter term. With these reductions, the Company anticipates maintaining Q1 reliability performance for its transmission assets but customers may experience some slippage within the Q3 performance of the Company's distribution assets. We will monitor the impact of these program and cost reductions on the reliability and safety of the aging electricity grid.

The Budget is consistent with the Company's mandate, vision, values and strategic objectives. A scorecard is used to measure annual progress toward the strategic objectives. The 2012 Scorecard uses weighting to place specific emphasis on productivity, reliability, customer satisfaction, employee engagement and financial performance. While these elements reflect the outcome of the work program, the safety aspects of how the work program is delivered are also considered in the Scorecard. A one page summary of the Hydro One Strategic Plan is attached as Appendix A. The work plan was developed on the basis of balancing our strategy, while recognizing the uncertainty of the Green Energy Plan, the global economy, and the new realities and challenges our customers face.

To address customers' concerns regarding bill impacts, increases in work programs over the Budget period have been limited, resulting in an average impact on total bill of less than 1.5% for both transmission and distribution customers. Rate increases are primarily driven by new infrastructure projects (Bruce x Milton) being included in rate base during the Budget period and reflect moderate growth in OM&A and capital spending. OM&A costs increase by less than inflation on average over the Budget period.

In developing the 2012 budget and 2013/2014 outlook, the company has identified approximately $280 million in productivity improvements and cost reductions.

- SAP tools are providing the information necessary to more effectively manage work, optimize investments in the assets and provide the necessary visibility to managers to control costs. The original SAP implementations are also providing effective platforms for seamless integration of new tools and applications, which support greater analytics and increase productivity. Cornerstone Phase 1, 2 and portions of Phase 3 that are complete are tracking to plan and are set to deliver approximately $135 million in benefits.

- Outsourcing Cost Savings. Additional savings have been achieved through the Inergi renegotiations; including project spend rebates, reduced charges for minor enhancements, and rate card savings, totalling approximately $65 million.
- Non-labour cost savings enabled by enhancements to telephone, video and web conferencing have reduced the cost and coordination required to effectively communicate across the organization while reducing travel expense and time. These total approximately $15 million.
- We continue to expand our SAP enabled transformation across the areas of Asset Analytics, Asset Investment Planning, Business Planning, Customer Information Systems, GIS and ongoing continuous improvement initiatives. These initiatives have a plan to achieve in the range of $50-60 million.
- Updates to the Wide Area Network to reduce leased line costs and increase bandwidth will result in savings of approximately $8-10 million.
- Business Transformational Initiatives. During the Business Plan period we will implement new initiatives in the areas of engineering design, work planning, scheduling, dispatch and mobility to further drive productivity and reduce cost.

Focus is maintained on reducing support expenditures for the Company by limiting salary and wage increases to reflect government guidelines. The Budget assumes a moderate growth in work program, but no increase in regular staff over the period. It includes several productivity initiatives and a resourcing strategy aligned with our focus on mitigating rate impact to our customers.

The Budget maintains Hydro One's focus on striking a balance amongst the expenditures associated with the implementation of the Long Term Energy Plan ("LTEP"), the costs and challenges of connecting distributed generation ("DG"), the execution of our sustainment programs and the realities of rate impacts on our customers. The Budget assumes no substantial change in the nature of the Company's role in the Ontario electricity industry, corporate mandate, or structure

The Budget delivers financial returns consistent with the return on equity ("Regulated ROE") permitted by the OEB while balancing, where possible, customer rate impacts and the requirements associated with aging infrastructure and government policy requirements. The Company continues to maintain strong credit ratings and has the ability to access capital at cost effective rates. The Budget continues to support those objectives and maintains acceptable levels of debt, financial metrics, return on equity and growth in corporate value as construction work in progress is converted into an increasing rate base over the Budget period.

[redacted]

The Company sought and received an exemption from the Ontario Securities Commission allowing it to file its Consolidated Financial Statements and MD&A in US GAAP for the period January 1, 2012 to December 31, 2014. Hydro One Networks has subsequently applied to the OEB to have rates set on the basis of US GAAP rather than modified IFRS for its Transmission business. A decision is expected by the end of November. The requests for the OEB to approve the use of US GAAP for the Distribution business and Hydro One Remotes are outstanding.

1. Purpose

The purpose of the Hydro One Board approved Budget submission, including the detailed analysis attached as Schedule A, is to ensure that the mandate of the Company regarding the safe, reliable and cost-effective transmission and distribution of electricity to Ontario's electricity users is achieved. The submission supports the governance, financial, and performance requirements of the Shareholder, while recognizing the needs of our customers.

The Corporate Business Plan is developed from Management's and the Hydro One Board of Directors' agreed Corporate Strategy and from the Hydro One Board of Directors' and Management's review of the risks that the Company faces. The Business Plan, as reflected in the Budget, attempts to mitigate the identified risks and to deliver a work program and financial performance that supports the Company in delivering the Corporate Strategy while at the same time recognizing rate impacts on customers. The Corporate Scorecard measures the Company's progress in achieving the Business Plan and the Budget metrics as it progresses forward in achieving the Corporate Strategy.

The Budget sets out the financial requirements for 2012 and requests approval to release work programs for the years 2012-14 through a structured process. Programs represent known recurring work and the structured multi-year release process is necessary to maximize critical skill sets, increase productivity and enable long lead-time materials to be acquired on a timely and cost effective basis. Work program flexibility to reprioritize work programs and projects, as required, will be maintained. Projects are released on the basis of individual business cases, as there may be several alternatives available with respect to scope and design. Implicit in the work program approval is the approval to purchase long-lead materials that support project work and work programs. Once approved, authority will be delegated to implement these requirements in accordance with the Organizational Authority Register.

2. Cost Estimate and Recovery

Key financial results in U.S. generally accepted accounting principles ("US GAAP") are as follows:

$M except where noted	**2011**(1)		[redacted]
Revenue	5,467		
Income before PILs	771		
Net Income	613		
EBITDA	1,723		
Cash Flow	(427)		
Debt Ratio	56%		
FFO Coverage	3.9x		
Total Rate Base	13,161		
ROE (GAAP)	10.1%		
Capital Expenditures	1,510		
OM&A	1,106		
Dividends	168		
PILs	157		
Total Long-Term Debt	8,132		
Total Equity	6,427		

(1) Projected

The Budget reflects growth in net income from 2012 to 2014. This growth reflects increases in transmission and distribution revenue requirements, consistent with work program requirements. Rate base growth, reflecting the in-servicing of ongoing capital work programs, is the primary cause for the increased revenue requirement and net income. The Shareholder reflects the Company's net income and PILs in the Province's books and records. Over the 2012 to 2014 period, these amount to [redacted] Common dividends have been managed to maintain capital structure and enterprise value.

The Budget continues to include significant funding requirements reflecting Government policy decisions and investments to maintain system reliability and safety. Highlights include:

- Transmission expenditures including component replacements, such as circuit breakers and metalclad switchgear, high voltage underground cable replacement, EOL transformer replacement, and other major EOL equipment replacements.
- Transmission sustainment investments at several critical stations (e.g. Manby, Leaside, Cherrywood, Burlington) to ensure operating reliability and development expenditures in Smart Grid to upgrade protections to enable DG. The Budget assumes that approvals required for planned work will be received by the distributed generators. In 2011, many of the approvals required to proceed with DG work and system expansion were delayed.
- Transmission development expenditures, including completion of Bruce x Milton, Commerce Way TS, Hearn TS, Leaside x Bridgeman 115kV circuit, SW Ontario Series Compensation Milton TS SVC, and a new 500/230kv station at the Oshawa Area TS, for which we recently received a communication from the Ontario Power Authority to begin planning for possible in-service date of 2015.
- Distribution sustainment work programs continue to reflect reduced expenditures consistent with the Ontario Energy Board's ("OEB") decision on our 2010/11 distribution application. The plan-over-plan reductions in vegetation management and line maintenance programs are partially offset by additional investments in Customer Care to support DG and smart metering activity.
- Distribution development expenditures primarily related to customer demand work, DG connections, and investments related to the rollout of Smart Grid as the development of the technical solution (Distribution Management System and intelligent field devices for monitoring and control) continues and will start to be implemented in areas of the Province where operational need is the greatest.
- Funding to address Environment Canada's final regulations governing the management, storage, and disposal of polychlorinated biphenyls ("PCBs").
- Funding for Phase 4 of the Cornerstone Project which will replace the Company's Customer Information System ("CIS") and further the productivity realization of the entity-wide platform. The project commenced in 2011 and remains on schedule for go-live in October 2012, with inclusion in rate base in 2013.
- Funding to comply with NERC cyber security requirements.

The Long-term Energy Plan ("LTEP") was released by the Government on November 23, 2010. The plan identified five priority transmission projects and Hydro One was instructed to undertake three of the projects. On February 17, 2011, the Government directed the OEB to include these three projects as part of our licence condition. The government also included an additional project, outside of the LTEP, to upgrade up to 15 transmission stations to accommodate small scale renewable generation (e.g. MicroFIT). The OEB updated Hydro One's transmission licence with these four conditions on February 28, 2011. As a result of delays related to environmental approvals and other items, the levels of investment in DG connections have been reduced to include only those projects where there is a clear line of sight to connection.

The LTEP also identified a new East-West tie ("EWT") line as a priority project to maintain long-term system reliability in Northwest Ontario. On March 29, 2011 the government expressed an interest that the OEB undertakes a designation process to select the most qualified and cost-effective licensed transmission company to develop the EWT project. Hydro One has entered into a partnership with Brookfield and affected First Nations to participate in the designation process. The plan provides $12 million in funding, in HOI, to participate in the OEB's designation process for the EWT project. Any funding requirements sought for the project will be brought forward to the Hydro One Board for approval as required.

The plan does not include funding for LDC acquisitions or assume any disposition of the Company's service territory. These opportunities will be managed as they arise.

3. Regulatory

The electricity industry in Ontario has undergone significant change during the past several years which has impacted customers' bills. The OEB has recognized customer concerns about rising costs and consequently, Hydro One will continue to face increased regulatory scrutiny of any request for rate increases.

An OEB decision on our request to adopt US GAAP for our Transmission business effective January 1, 2012 is expected by the end of November. Hydro One will file a request to have distribution rates declared interim on January 1, 2012. As part of the interim rate request, Hydro One will seek approval to adopt US GAAP for the Distribution business. A request will also be made to have Hydro One Remote Communities file for use of US GAAP in its rate applications.

In April of 2012, in order to support Business Plan and Budget requirements, Hydro One intends to file a combined transmission and distribution multi-year rate application that would cover transmission and distribution rate requirements for 2013 and 2014 and distribution rate requirements for 2012.

If approved, transmission rates would increase by approximately 7.0% in 2013 and 10.2% in 2014, (an average of 0.65% increase on the total bill, each year). These increases support aging infrastructure and government supply mix initiatives.

[redacted] No increase is proposed for 2012 with existing rate riders and variance accounts remaining in place until 2013. [redacted]

In the event the OEB imposes an Incentive Rate Mechanism ("IRM") on Hydro One's Distribution business, or significantly reduces the work program for either the Distribution or Transmission business, system reliability will decline.

4. Risk Summary

There are a number of risks which could impact the accomplishment of this Budget. Although most of the risks are consistent with prior business plans, the level of certain risks has increased. First Nations and Métis Relationship uncertainty remains a very high risk. We anticipate the likelihood of this risk to increase and to impact our ability to complete work programs and projects. The United

Nations Declaration on the Rights of Indigenous Peoples and the concept of "free prior and informed consent" are increasingly used by First Nations and Métis as leverage for consultation, which the Company is required to undertake. There is a very real risk that both future work and work in progress could be delayed until First Nations and Métis expectations are met.

Additionally, four new risks have been identified since the last Budget: Labour Relations Uncertainty, Outsourcing Risks, Cost Reduction/Productivity and Human Resources Risk. These risks are, to some extent, interrelated. It is anticipated that there will be continued pressure from the Shareholder and the OEB to reduce labour and work program costs. Reduced labour costs and/or productivity improvements are critical to support a growing work program without an associated growth in regular staff. These pressures will converge as we approach expiry of both the PWU and Society collective agreements in 2013 and the issuing of an RFP in 2013 for the renewal of the outsourcing services agreement, which expires February 2015.

Other significant risks that Hydro One faces include: uncertainty of government policy; increased risk of equipment failure due to increased age; uncertainty regarding future investments prompted by the Green Energy Act; an increasingly complex regulatory environment; availability of staff resources to execute the work program; increasing reliance on information technology; cyber threats and virus attacks; and the possibility of new NERC compliance requirements which may be applicable to our transmission and distribution systems.

SCHEDULE A

HYDRO ONE INC.
2012 BUDGET & 2012 to 2014 OUTLOOK

1. INTRODUCTION

The 2012 Budget and 2013/2014 Outlook ("Budget") summarize the financial results reflecting Hydro One Inc.'s ("Hydro One" or "the Company") commitment to making necessary investments in core Transmission and Distribution infrastructure, consistent with the Strategic Plan. Hydro One's focus continues to be on the operating, productivity and economic performance of the core utility operations (comprising Hydro One Networks Inc.'s ("Networks") Transmission and Distribution businesses, Hydro One Brampton Networks Inc. ("Brampton") and Hydro One Remote Communities Inc. ("Remotes")) to provide safe, cost-effective and reliable electricity delivery services to our customers, and providing increasing enterprise value to our shareholder, the people of the province of Ontario. Productivity, value for money and improved employee and customer communications will be key areas of focus. The Budget includes investments required to connect and support Distributed Generation ("DG") and investments made consistent with the Long Term Energy Plan ("LTEP").

This Budget and the underlying business plan are based on a number of assumptions which are included in Section 3 "Key Planning Assumptions". If, subsequent to approval of the Budget, information arises or decisions are made that materially impact these assumptions, including from regulatory decisions, this Budget will be revised and resubmitted to the Hydro One Board of Directors for consideration and approval.

2. STRATEGY

ii) Productivity and Cost-Effectiveness

Productivity improvements and cost-effectiveness, together with innovation, are the keys to delivering a work program that ratepayers can afford. Productivity cost reductions of approximately $280 million across the 2012 to 2014 period have been embedded in the plan.

Effective use of human resources and ensuring correct skills will be critical to attaining the balance between meeting the asset needs and mitigating rate impact on the customer. Although the work program will grow by an average of 3% per year through 2016, regular headcount will be maintained at 2011 levels. As attrition occurs, staff mix will be reviewed to ensure that support costs are being minimized through the effective use of tools and technology. We will continue to hire new staff through the apprenticeship programs based on the required staffing ratios.

Union contractual limitations to operational flexibility will be identified with a view to negotiating alternatives that meet the needs of both Hydro One and the Unions. Our focus must continue to be the timely effective training of new resources, documented procedures and job aids to maximize knowledge transfer. Managing costs associated with benefits, and rising labour costs will also be a priority.

Emphasis will be placed on management to be more effective in their use of staff. Management will be held accountable in ensuring required work programs are delivered efficiently and effectively. Management effectiveness programs and measures, currently being piloted through the Craft of Management program, have been well-received and will be further deployed across the Company to aid in achieving these objectives.

iii) Reliable Transmission and Distribution

To ensure the electricity system's reliability in the public interest, we are planning significant investments in the transmission and distribution infrastructure. The Budget includes investments to maintain, refurbish and replace existing assets that have reached their end-of-life ("EOL"). These investments will continue to focus on specific mission critical equipment and stations that support generation facilities and the unrestricted supply of energy to customers throughout the Province, as well as responding to customer supply issues.

The success of the SAP system replacement has created an opportunity to access and manage large amounts of data enabling the asset managers to perform comprehensive reviews of asset performance. The preliminary results of major asset categories indicate that Hydro One's assets are in the midst of a profound demographic change: the rapid aging of its infrastructure as reflected by an increasing proportion of assets reaching EOL and an increasing average asset age. The table below identifies the EOL statistics for our major asset categories.

EOL Demographics by Asset Portfolio

Asset Portfolio	**Current EOL** % of Fleet Currently at Demographic EOL	**10yr EOL*** % of Fleet at Demographic EOL in 10yrs
Tx Protections	32%	54%
Dx Stations Transformers	32%	50%
Tx Circuit Breakers	30%	51%
Tx Power Transformers	27%	49%
Tx Wood Poles	27%	33%
Tx Underground Cables	19%	36%
Tx Overhead Lines	16%	32%
Tx Steel Structures	14%	25%
Dx Wood Poles	5% + 3% [redacted] (degrading prematurely)	29% + 3% [redacted]

* Assumes assets are not upgraded, refurbished or replaced over 10-year period.

Ongoing analysis of asset requirements using the SAP tools will continue to be conducted and evaluated to ensure safety and reliability of the system is optimized within financial and resource constraints.

iv) Satisfying Our Customers

Various initiatives will be undertaken during the planning period to maintain or move toward the target of 90% overall customer satisfaction. Customer satisfaction is currently tracking lower than target. Results are being pressured due to industry rate increases required to implement Government Policy initiatives and to fund necessary investments. Hydro One's customers have experienced an unprecedented period of change (e.g. smart meters, time-of-use ("TOU") billing) and a six-year period of rising rates to support much needed electricity infrastructure reinvestment. This activity against a backdrop of a poor economy and high levels of unemployment continues to erode customer satisfaction.

At the heart of customer discontent is the lack of awareness and understanding of electricity and Ontario's electricity sector and the value customers receive in return for their rates. We are focused on proactive customer interactions at all levels, such as calls to customers to triage abnormally large TOU bills prior to issuance and through the use of a special team of agents to handle distributed generator inquiries and requirements. In addition, the implementation of our new Customer Information System ("CIS") will allow us to address current needs and realize immediate value by replacing a costly stand-alone system with a more flexible platform. The capability enhancements of CIS will allow us to improve on key metrics directly linked to our 90% Customer Satisfaction goal as it will provide analytic and segmenting capability to establish customer profiles and ensure customer communications are targeted, meaningful and timely.

As part of our strategic plan, innovation is a key enabler to address aging infrastructure needs with technological advances in the utility sector. Hydro One strives to balance being an industry leader in developing innovations that better serve our customers with the economic reality of increasing rate pressures. Hydro One is a world leader in Smart Metering and the implementation is essentially complete with 1.05 million customers converted to TOU as of June 30, 2011, all of which is unprecedented in North America. The current plan provides for further conversion of customers to TOU using the smart meter communications networks and technical variations to increase network reach where it is commercially justifiable to do so. It also includes an allowance to develop a tool to manually extract the interval data for the smaller number of customers where the development of the communication network is uneconomic.

Smart Grid leverages the Smart Meter data and the communications network already deployed to address the integration of DG in our distribution network. The technical solution for Smart Grid continues to be developed and a Distribution Management System ("DMS") combined with intelligent field devices will start to be implemented in areas of the Province where the operational and customer need is greatest. Smart Grid not only supports DG, but can be leveraged in many ways to increase productivity such as automated crew dispatch and effective outage management, also benefiting our customers. Through the use of Smart Grid technology we will be able to better manage the amount of system rebuild required to support embedded renewable generation.

v) Employee Engagement

Employee engagement is a critical success factor given the challenges of leadership succession and retention, labour demographics and development of critical staff. An engaged staff has been identified as a key element in driving work efficiency and effectiveness and high levels of customer satisfaction. The Q12 survey will continue to be utilized as both a gauge of current employee sentiment, and a platform from which to implement improvements.

As the Craft of Management Program continues to be rolled out, the resulting clarity in accountability is improving decision-making. It is also highlighting areas where the organizational structure is not enabling effective work practices. Organizational changes are being made as a result.

vi) Shareholder Value

Consistent with the Memorandum of Agreement with our Shareholder, the Province of Ontario and as a reporting issuer under the Ontario Securities Act, we are required to operate on a financially sustainable basis and to maintain or increase the value of assets for our Shareholder. The Budget delivers financial returns consistent with the return on equity ("Regulated ROE") permitted by the OEB while balancing, where possible, customer rate impacts and the requirements associated with aging infrastructure and government policy requirements. The Company continues to maintain strong credit ratings and has the ability to access capital at cost effective rates. The Budget continues to support those objectives and maintains acceptable levels of debt, financial metrics, return on equity and growth in corporate value as construction work in progress is converted into an increasing rate base over the Budget period.

vii) Injury-Free

Given the nature of our work, safety remains the Company's top priority. We continue to focus on creating an injury-free workplace and maintaining public safety through several health and safety initiatives, including Journey to Zero. We continue to build on programs like Employee Health and Wellness for mental health issues, and Ergonomic assessments for musculoskeletal disorders to positively impact our employees' well-being. The Company has passed the WorkWell audit and is targeting OHSAS 18001 registration in 2013.

3. KEY PLANNING ASSUMPTIONS

The Budget is based upon a number of key assumptions. Given the level of uncertainty in the industry, new information, such as rate decisions and policy direction, could materially impact the validity of the underlying assumptions and ultimately the achievement of the Budget. The key planning assumptions are outlined below.

i) Regulatory

The financial results being put forward are predicated on obtaining timely OEB approval for rate increases for the 2013 and 2014 test years consistent with infrastructure requirements. No increase is proposed for 2012 with existing rate riders and variance accounts remaining in place until 2013. The Regulated ROE for 2012 is 9.42% down from 9.66% in 2011. In 2013 and 2014, the Regulated ROE is projected to be 9.7% and 10.2%, respectively.

ii) Government Policy and Green Energy

Hydro One's expenditures in the Budget for DG Green Energy initiatives are based on the experience gained since 2009 and the changes to the Feed-in-Tariff (FIT) program that have occurred. For the larger Non-Capacity Allocation Exempt (CAE) projects, only expenditures for projects with FIT contracts and signed connection agreements that are expected to connect to Hydro One's distribution system are included in the Budget. The Budget also includes expenditures for CAE and MicroFIT projects that are expected to connect. Incorporation of distributed generators on the distribution network is being assisted by the results of Hydro One's Smart Grid Advanced Distribution System ("ADS") initiative. The integration of a DMS, combined with intelligent field devices, will provide the platform to address challenges posed by distributed generators. For 2012 through to 2014, Hydro One is requesting the continuation of the variance accounts approved by the Board in the previous proceeding along with the rate riders.

The Ministry of Energy released Ontario's LTEP on November 23, 2010. The LTEP identifies five priority transmission projects as follows:

- Devices to enhance the transfer capability, such as series or static var compensation or similar devices, in Southwestern Ontario; – in-service 2015
- Re-conductor circuits West of London; – in-service 2014
- New Line West of London; – in-service 2017
- East-West Tie ("EWT") line; – in-service 2016-17
- New Line to Supply Pickle Lake; – in-service pending consultation

On December 22, 2010, the Minister of Energy provided an update to the September 21, 2009 letter. The update does not specify the disposition of all the projects that the then Minister of Energy and Infrastructure asked Hydro One to immediately plan, develop and implement in anticipation of the Feed-in-Tariff program. The letter requests Hydro One to immediately proceed with the necessary planning and development work to advance the first three of the priority projects; devices to enhance transfer capability in Southwest Ontario such as series or static var compensation; re-conductoring of Sarnia to London Circuits and; a new transmission line west of London.

On February 17, 2011, the Minister of Energy directed the OEB to amend the licence conditions of Hydro One to include a requirement that Hydro One proceed with the first three priority projects stated in the letter of December of 22, 2010 and also included the requirement to increase the short circuit and/or transformer capacity at up to 15 of Hydro One's transmission stations. These licence amendments were executed by the OEB on February 28, 2011.

The Supply Mix Directive was issued to the Ontario Power Authority ("OPA") on February 17, 2011 by the Minister of Energy. The Supply Mix Directive outlines the Government's goals to be achieved through long term Integrated Power System Plan to be developed by the OPA and submitted to the OEB for approval.

Hydro One has included funding for the development and implementation of the three priority transmission projects in the Budget. On June 30, 2011 Hydro One started work on the re-conductoring of the West of London circuits based upon the OPA's recommendation. On October 3, 2011, work began on installing a static var compensation device at the Milton Switching Station based on the recommendation of the OPA. Work on the New Line West of London will commence once an appropriate letter is received from the OPA. The current plan assumes that preliminary work will commence in 2013.

The OEB released a new policy paper on August 26, 2010, *Framework for Transmission Project Development Plans*, which provides for competitive bidding for various types of new build projects. This process also allows the OEB to designate projects to the incumbent transmitter in certain situations.

On March 29, 2011, the Minister of Energy sent a letter to the OEB to "express the Government's interest that the OEB undertake the designation process to select the most qualified and cost effective transmission company to develop the EWT." In response to the OEB's request to the OPA, the OPA has submitted a report to the OEB regarding the preliminary assessment of the need for the EWT line. On August 22, 2011, the OEB invited licensed transmitters to register their interest in filing a plan to develop the EWT project by September 21, 2011. As a result, seven licensed transmitters registered including EWT LP of which Hydro One is a partner. Hydro One Networks did not register. The Budget does not provide funding for the EWT project.

As per the OEB's approval, we are continuing to account for allowance for funds used during construction on the Niagara Reinforcement Project and monitoring for changes in the status of the project.

iii) Load

The transmission load is forecast to decline by 1.1% in 2012, 2.5% in 2013 and 0.6% in 2014 primarily due to the effects of CDM. The transmission load forecast reflects the current OPA CDM forecast. Similarly, the distribution load is forecast to decline by 0.5% in 2012 and 0.3% in 2013. The distribution load is forecast to increase by 0.4% in 2014.

iv) Employees

Staff Headcount	2012	2013	2014
2012-14 Budget	5,913	5,913	5,916
2011-13 Budget	6,182	6,217	6,306
Variance	(269)	(304)	(390)

Although the Budget assumes a moderate growth in work program, there is no increase in regular staff over the period. On a plan-over-plan basis, staff levels have been reduced significantly due to a lower work program and the limitations placed on support staff. Salary and wage levels reflect government guidelines. Management salaries were frozen in 2010 with the exception of first level managers to address compression with union staff.

The Company has reviewed the employee benefit cost forecasts and the assumptions relating to health care trend rates, demographics, and claims data have been updated. Although Hydro One has not granted new benefits to employees, benefit costs (excluding pension costs) have increased in aggregate compared to last year (2012 Budget of $188 million versus $173 million in the 2011 Budget). The increase is primarily due to the lower discount rate at the end of 2010.

Annual pension contributions are established as a result of a pension valuation which is completed tri-annually. A new pension valuation was received in 2010, resulting in increased annual pension contributions (2012 Budget of $149 million versus $143 million for 2011). No new pension entitlements have been granted. The next valuation for the Hydro One defined benefit plan is December 31, 2012 with a new annual contribution amount payable in 2013. It is anticipated that if long-term interest rates remain low and stock markets do not perform that this amount will increase significantly from the existing levels. Similarly with limited smoothing options available, employee benefits will also be impacted by lower interest rates which increase the present value of the future liability, increasing annual contribution amounts. The Company is looking at how it can mitigate these increased costs as they directly impact customer rates. In previous contract negotiations, the Company has worked with its Unions to change the benefits payable under the plans or increase employee contributions.

v) Financial

Consistent with the 2012 financing plan, authority has been sought from the Board of Directors to borrow [redacted] This will be sufficient to meet the remaining [redacted]o meet long term debt maturities in 2012-13, and provide funding for unexpected requirements. To maintain enterprise value and to address the requirements of the capital program, while maintaining financing ratios and the deemed regulated equity structure, common dividends have been managed to maintain the capital structure. [redacted] Payments to the Shareholder through payments in lieu of taxes and dividends, over the Budget period are, [redacted]

For 2012 to 2014, the statutory tax rate has declined from last year's budget based on rates enacted in 2011. The Budget reflects the statutory tax rates of 26.25% in 2012 decreasing to 25.50% and 25.00% in 2013 and 2014, respectively.

This Budget also assumes that work program execution strategies to address identified risks will be successful. These strategies include a variety of initiatives dealing with work program execution, and include the procuring of materials and land acquisition, various regulatory and other required approvals, obtaining funding and the ongoing maintenance of First Nation and Métis relationships.

4. Regulatory Issues

An OEB Decision on Hydro One's request to adopt US GAAP for our Transmission business effective January 1, 2012 is anticipated by the end of November. A similar request will need to be made for US GAAP to also be applicable for distribution as part of the interim rate request. If successful, previously approved transmission rates for 2012 would be approximately 15% lower pending an OEB cost of capital update expected to be announced in November. The plan assumes after Board approval of the reduction that approved transmission rate increase will be 8.2% for 2012.

Similarly, if US GAAP is allowed for regulatory filing purposes for the Distribution business distribution rates will avoid an approximate 14% increase.

If approved by the OEB, the Company's initiative to move its financial reporting to US GAAP basis will have a beneficial impact on reducing customer rates.

A combined cost-of-service application is planned for 2013 and 2014 with proposed Regulated ROEs of 9.7% in 2013 and 10.2% in 2014 based on the application of the OEB's cost of capital report. If approved, transmission rates would increase by approximately 7.0% in 2013 and 10.2% in 2014, (an average of 0.65% increase on the total bill, each year). These increases support aging infrastructure and government supply mix initiatives.

[redacted] No increase is proposed for 2012 with existing rate riders and variance accounts remaining in place until 2013. The increase in 2014 follows an effective rate freeze in 2012 and 2013. Rate increases in 2014 and beyond are driven primarily by additions to rate base and moderate increases to work programs.

5. Financial Accounting Framework

The International Accounting Standards Board, which sets IFRS, did not reach a consensus on whether, when or how regulatory assets and liabilities will be recognized for financial reporting purposes as part of a future standards setting project. In light of this indecision, the Company sought and received an exemption from the Ontario Securities Commission allowing it to file its Consolidated Financial Statements and MD&A in US GAAP for the period January 1, 2012 to December 31, 2014. It is currently unclear what accounting framework will by used in 2015 and later years. If indecision continues with IFRS accounting the Company has the option, in the future, to become a Securities Exchange Commission registrant and continue to file and prepare its financial statements under US GAAP.

For subsidiary reporting, all units except Hydro One Brampton and Hydro One Telecom will also adopt US GAAP. Brampton and Telecom will use IFRS.

US GAAP is very similar to legacy Canadian GAAP (CGAAP) with the exception of minor differences in the presentation of preferred shares on the balance sheet and adjustments related to accounting for employee future benefits costs. The Company's preferred shares, which are held entirely by the Province of Ontario, will be classified as mezzanine equity under US GAAP. In accordance with OEB rate orders, pension costs are recorded under CGAAP when employer contributions are paid to the pension fund in accordance with the *Pension Benefits Act* (Ontario). Pension costs will be recorded in the same way under US GAAP. Employee future benefits other than pension are, and will continue to be recorded on an accrual basis. There are minor differences between Canadian and US GAAP for certain employee future benefits costs. However, Hydro One does not expect any significant change to the net asset position on our Consolidated Balance Sheet. Nor does it expect significant impacts on the Consolidated Statement of Operations following the application of US GAAP to employee future benefits costs.

In addition to the external reporting change, Hydro One Networks has applied to the OEB to have rates set on the basis of US GAAP rather than modified IFRS. A decision is expected at the end of November. Hydro One Remotes is expected to make a similar request in future. Brampton will retain modified IFRS for rate making purposes.

6. FINANCIAL RESULTS

The adjacent table summarizes key financial results for the 2011 to 2014 period. Revenues, net income, and EBITDA increase over the planning period reflecting a growing rate base in both transmission and distribution as a result of core infrastructure investments.

The financial results support our credit fundamentals and our credit metrics have improved due to the reduction in the capital program. Bearing any negative industry impacts, the Company's "A" credit rating should remain stable.

Dividends are managed to maintain capital structure and enterprise value.

Hydro One Inc. (USGAAP)	**2011 Projn**	[redacted]
Revenue ($M)	5,467	
Income before PILs ($M)	771	
Net Income ($M)	613	
EBITDA ($M)	1,723	
Cash Flow ($M)	(427)	
Debt Ratio (%)	56%	
FFO Coverage (X)	3.9x	
Total Rate Base ($B)	13,161	
ROE (GAAP) (%)	10.1%	
Capital Expenditures ($M)	1,510	
Dividends ($M)	168	
PILs ($M)	157	
Cash Requirements Incl. Refinancing ($M)	(1,422)	
Long-Term Debt ($M)	8,132	
Regular Staff	5,888	

7. SUBSIDIARY HIGHLIGHTS

7.1 Hydro One Networks – Transmission

Networks Transmission (USGAAP)	2012 Budget	2013	2014
Net Income ($M)	379	417	470
Regulatory ROE (%)	9.4%	9.7%	10.2%
OM&A ($M)	443	452	460
Capital ($M)	962	1,070	1,089

Net income and ROE for 2012 reflect the transmission cost-of-service decision rendered by the OEB on December 23, 2010, assuming we are successful with our subsequent request to adopt US GAAP. Net income and ROE for 2013 and 2014 are based on planned cost-of-service applications. Net income is based on assumed rates consistent with the OEB-prescribed formula to calculate allowed returns along with the interest forecast and a rising rate base.

Our Transmission system is aging and a significant portion of the assets are deteriorating at an increasing rate. Plan over plan, Transmission OM&A expenditures are reduced. Funding limitations will be addressed by implementation of asset analytics to target investment needs. Investments are risk based considering: asset condition; safety; performance; system function; customer impact and statutory requirements. Over the Budget period, Hydro One plans to make investments at several critical stations (e.g. – Manby, Leaside, Cherrywood, Burlington) to ensure operating reliability. Other significant sustainment investments are planned to address asset condition or additional requirements in the following areas:

- Stations – reinvestments to replace end of life equipment, such as air blast circuit breakers, metal clad and gas insulated switchgear
- Replace end of life high voltage underground cables
- Transformer fleet – replace transformers that are at end of life or in poor condition
- Auxiliary telecommunication equipment – replace end of life tone equipment, copper cable and power line carrier systems which are critical elements in the operation of protection systems,
- Stations PCB inspection and testing program required to meet PCB regulations by 2014 extension deadline. The Company remains at risk for completing work programs designed to meet the PCB deadlines.
- Increased investments to comply with NERC cyber security requirements

Transmission development investments over the Budget period are primarily in response to government policy initiatives, system investment needs or customer requirements. Our major capital investments over the Budget period include (net $): Bruce x Milton ($695 million), Commerce Way TS ($43 million), Hearn TS ($101 million), Leaside x Bridgeman 115kV circuit ($76 million), SW Ontario Shunt Compensation Milton TS SVC ($100 million), and a new 500/230kv station at the Oshawa Area TS ($270 million). Transmission investments for Smart Grid and requirements to enable DG are also included in the Budget.

Year-over-year, transmission OM&A expenditures increase marginally from 2012 to 2014 but ramp up in the later years as aging infrastructure needs accelerate. These expenditures address corrective and preventive maintenance, including power transformers (auto and step-down), and regulators as maintenance and mid-life refurbishments on the fleet of approximately 280 high-voltage transmission stations, 29,000 circuit-kilometre high voltage network and 20,700 kilometres of rights of ways are addressed.

Transmission capital expenditures increase from 2012 to 2013 mainly due to increased sustainment investments for system and stations reinvestment to replace end of life air blast circuit breakers, underground cable, auxiliary telecommunications equipment, aging power transformers and to comply with NERC cyber security requirements. These increases are partially offset by decreasing development spending primarily related to Bruce x Milton. From 2013 to 2014, Transmission capital expenditures increase due to the new 500/230kv station at the Oshawa Area TS and increased sustainment spending for system re-investment to replace end of life assets. This is partially offset by the completion of the rebuild of Hearn TS.

7.2 Hydro One Networks – Distribution

Net income and ROE for 2012 reflect no increase to the proposed 2012 distribution rates with existing rate riders and variance accounts remaining in place until 2013. Net income and ROE for 2013 [redacted] are based on planned cost-of-service applications. Net income increases over the period, reflecting the assumed rate changes based on the OEB-prescribed formula to calculate allowed returns along with the interest forecast and a rising rate base.

Networks Distribution (USGAAP)	2012 Budget	2013	[redacted]
Net Income ($M)	237	264	
Regulatory ROE (%)	9.4%	9.7%	
OM&A ($M)	566	582	
Capital ($M)	731	635	

Distribution OM&A expenditures for 2012 to 2014 period are mainly for sustainment programs such vegetation management across the Province, trouble calls and disconnect/reconnect requirements associated with our 123,500 circuit kilometres of low-voltage distribution lines, numerous stations and approximately 1.3 million rural and urban customers.

Consistent with the prior plan, Hydro One's distribution OM&A sustainment work program in 2012 continues to reflect reduced expenditures as per the OEB's decision on our 2010/11 rate application. The reductions were primarily applied to the vegetation management and line maintenance programs, and were scaled to accommodate additional investments in Customer Care that support DG customers and smart metering activity. The total reductions to the vegetation management program do not enable an eight-year forestry clearing cycle. This means that rights of way will contain denser brush that is more costly to manage and has a higher probability of producing tree-related outages. Currently, approximately 50% of customer outages are related to trees. Thus, system reliability could decline as a result of these reductions, and trouble calls could increase. In terms of line maintenance programs, the number of planned defect corrections has been reduced below historical levels. This increases the risk of failures and trouble calls. System reliability will be monitored closely and by leveraging asset analytics tools the limited investments will be prioritized to minimize customer impact while maintaining safety and reliability.

Distribution development capital expenditures over the Budget period are primarily related to Smart Grid development, customer demand work (connections and upgrades), DG connections, including station upgrades, protection and control, new lines and some contestable work for which we receive capital contributions. There is little flexibility with reducing this work as most of it is demand driven.

The roll out of Smart Grid will continue through the 2012 to 2016 period. In 2012, Smart Grid continues to focus on the development of the technical solution and the beginning of its implementation in areas of the Province where operational need is greatest. The early focus will be the integration of the DMS with power system intelligent electronic devices to support embedded

DG, but it will also leverage the integration of the existing outage management system and automate crew dispatch.

Plan over plan, the expenditures are significantly reduced. This is in part due to expenditures for DG as these expenditures have been reduced based on the experience gained since 2009 and changes to the FIT Program that have occurred. For the Mid-to Large Non-CAE Projects, the Budget only reflects expenditures for projects with FIT contracts that are expected to connect to Hydro One's distribution system. The Budget also includes expenditures for CAE and MicroFIT projects that are expected to connect.

In 2012, the reductions to sustaining and development are partially offset by a major capital expenditure compared to the last plan in Phase 4 of Cornerstone, which will replace the Company's CIS. The system is near end of life, and costly to maintain and operate. The discovery phase commenced in 2011 with implementation ongoing. The project commenced in 2011 and remains on schedule for go-live in October 2012, with inclusion in rate base in 2013. Under US GAAP the accounting in-service date, and the date when the assets will be included in rate base, is based on the completion of system testing which is expected to occur in 2013.

We continue to focus on support expenditures for the Company as a whole by maintaining salaries and wages consistent with Government guidelines and reductions in non-labour costs to mitigate the impact of the work programs as well as upward pressure from new and emerging obligations.

Distribution capital decreases from the 2012 to 2013 period mainly due to the conclusion of the replacement of the Company's CIS and lower investments for Smart Meters as the program comes to completion. The lower costs are partially offset by the required higher investments for wood pole replacements and the sustainment of distributing and regulating stations as assets continue to age. The wood pole replacement program increases by roughly $20 million (net) annually from 2012-2016 as the Company increases the investment to replace 15,000 poles on average each year. This addresses an aging population of 1.7 million poles of which 32% are approaching EOL over the next ten years.

Investments in Smart Grid and DG are significant throughout the planning period, but decline as the programs reaches maturity in later years.

7.3 Hydro One Brampton Networks Inc. ("Brampton")

[redacted]

[redacted]

7.4 Hydro One Remote Communities Inc. ("Remotes")

[redacted]

7.5 Hydro One Telecom Inc. ("Telecom")

[redacted]

[redacted]

8. BORROWING REQUIREMENTS

[redacted]

Issuance conditions deteriorated in the second half of 2011 with increasing concerns over Europe's debt crisis and an increased risk of a global recession or slowdown. There are numerous sources of uncertainty that could adversely affect market conditions over the medium term. As such, volatility and intermittent market disruptions are expected to remain a feature in the financing environment for some time. [redacted]

[redacted]

9. RISKS

As reflected in the Corporate Risk Profile, there are a number of risks that could impact the accomplishment of this Budget. In developing its business plan and Budget, Hydro One has sought to minimize the quantity and magnitude of the risks it faces. Although most of the risks are consistent with prior business plans, the level of certain risks has increased. The newly identified risk sources (Labour Relations Relationship Uncertainty, Outsourcing Risks, Cost Reduction/Productivity and Human Resources Risk) are likely to pose significant challenges.

Labour Relations Uncertainty
Collective Agreements with both the Power Workers' Union and the Society of Energy Professionals expire in 2013. Pursuant to Government direction, the Society of Energy Professionals' contract will be under a net zero guideline. Outcomes of those collective bargaining negotiations will be critical to increasing the effectiveness of the existing cost structure in light of continuing Shareholder and OEB expectations regarding cost reduction. It is also expected that the expiry of the Inergi Outsourcing contract in February 2015 will be of significant interest to the unions as the majority of the Inergi staff are represented by the two unions.

The plan assumes that we can resource the work programs and projects partially by replacing the retiring work force with those whose skills are more appropriate to completing the planned programs. If we do not get the expected level of attrition, or experience labour union pushback, we may not be able to complete the program.

Human Resources Risk
Execution of the plan is contingent upon the Company's ability to obtain the necessary staffing resources. The demand for experienced professional engineers in disciplines such as Protection and Control is high and resources within the Company and available externally with the knowledge of our system are limited. Over the next five plus years, Hydro One faces the possibility of a shortfall of qualified resources as we move forward with the large volume of work to meet asset needs and is faced with the increasing loss of qualified staff due to retirements.

Ignoring eligibility to retire and looking at the current work force who will be 60 and over in each year, currently 328 employees are 60 years of age or older or 6% of the existing work force. In 2012 the number increases to 419 (increase of 91). In 2013, the number increases to 533 (increase of 114). In 2014, the number increases to 688 (increase of 158). In 2015, the number increases to 1,014 (increase of 168) or approximately 18% of the existing work force.

At present, approximately 1 in 4 staff are eligible to retire. Five years from now, more than 1 in 3 could have retired. Although actual retirements have significantly lagged eligibility, the retirement rate has recently increased and could accelerate if the economy improves. Continued compensation freezes, coupled with wage compression with represented staff and future uncertainty may pose an MCP retention risk. Despite the effectiveness of hiring, training, and succession planning, the knowledge loss is likely to be impactful.

First Nations and Métis Relationship Uncertainty remains a very high risk. The expectation is that this risk will likely increase. The United Nations Declaration on the Rights of Indigenous

Peoples and the concept of "free prior and informed consent" are increasingly used by First Nations and Métis as leverage for consultation. There is a very real risk that both future work and work in progress could be delayed until First Nations and Métis expectations are met. Recent court rulings continue to support First Nations where First Nations territory or ancestral rights are impacted. Hydro One has a duty to consult where First Nations rights may be impacted. Further, the Shareholder has stated an expectation for First Nations and Métis to become equity partners in energy projects as well as to have employment and procurement opportunities. Hydro One has entered into such a partnership for the purpose of bidding on the East West tie line, however the outcome, complexity and effectiveness of First Nations partnerships as they relate to electricity transmission projects is unknown.

Government policy uncertainty remains a significant risk to the Company. Over the past several years, significant changes have been introduced in the electricity sector. Customer rates have increased dramatically due to the combined impact of rate harmonization, harmonized sales tax, higher costs of power, conservation programs, smart meter costs, higher returns on equity for regulated utilities, and increased investment by electrical utilities in maintenance and capital replacement. The cost of new generation, Green Energy Act costs, and continued investments required to maintain an aging system are likely to increase costs further. Coupled with hotter weather, customers are reacting to the higher costs for electricity. Any significant implications to rates could impact our ability to maintain the network, our ability to maintain our financial fundamentals and could have a detrimental effect on our own productivity and efforts to improve cost effectiveness. Hydro One will continue to consider customer rate impacts, to educate customers on how to be more effective in their use of electricity and to manage customer expectations.

The **Green Energy Act** remains uncertain. The LTEP formed the basis of the Government's Supply Mix Directive, dated February 17, 2011, that directed the OPA to prepare an Integrated Power System Plan (IPSP). The IPSP requires approval by the OEB and it is unclear when this process will be complete and what the work requirements will be for Hydro One. We are concentrating our efforts on DG and may not be able to react to an unplanned requirement on a timely basis, putting in-service dates at risk.

The DG program also poses significant challenges to Hydro One which could impact the quality, reliability and safety of the system as well as customer satisfaction. Our distribution system was not designed to support large scale connection of Distributed Renewable Generators. For example, it was designed for unidirectional flow. Consequently, reinforcements, protection upgrades and operating tools are being developed to monitor and manage these connections. Our Distribution system does not have the load level consistent with jurisdictions that have distributed generation and it is not clear how the mix of generation formats will work together. The required solutions to connect DG are new to our system and therefore riskier. In addition, the Distribution System Code is not specific as to who pays for upgrades. Additional upgrades may be required after generators are connected. Hydro One has requested and been granted that certain upgrades be funded by all rate payers.

The risk to our ability to fully process all generator applications on a timely basis could continue to be high and is difficult to estimate. Hydro One has developed and executed processes to address connection requirements. However, if volume continues or timelines compress, increases in staff will need to be redirected from the work programs which could impact system reliability.

Infrastructure
Many of our Transmission and Distribution assets are close to or beyond their expected life which could result in a multitude of unexpected equipment failures. In addition, portions of our

Transmission system require upgrades to safeguard redundancy in the network and to handle new generation. Property owner resistance to new development as well as First Nations and Métis interests contribute to this risk. Mitigation is provided by higher planning priority for mission-critical parts of the system, real time system monitoring, emergency response capability and stakeholdering with Government agencies and the public on the challenges of new transmission.

As the electrical utility industry moves to automation on the Distribution network the vendor community continually develops digital technologies that leverage IT systems. As Hydro One moves to replace aging infrastructure it is not possible to replace components on a "like-for-like" basis. Hydro One is increasingly more reliant on **complex computer technology** which is subject to cyber threats and virus attacks. In addition new technologies such as the Advanced Distribution System place considerable dependence on new developing information technology which represents an industry leading way to operate, manage and maintain key distribution assets.

The U.S. Federal Energy Regulatory Commission (FERC) is focused on having the same of level of security and Systems Control and Data (SCADA) that applies to 500KV transmission lines apply to lines with a rating of 100 KV or more. Hydro One is actively participating in two working groups to influence the applicability of these proposed rules. If the new rules are adopted, and if Hydro One is required to adhere to these rules, our costs will increase significantly as we upgrade SCADA and cyber security infrastructure to be compliant.

Customer Relationship
Despite a focus on mitigating customer rate impact, factors both internal and external to Hydro One will continue to exert upward pressure on rates. While CIS is expected to have long term benefits which will increase customer satisfaction, it is considered to be the highest risk Phase of Cornerstone.

The **regulatory environment** that Hydro One faces has become increasingly complex and the demands of the regulators (e.g. ESA, OEB, FERC, NERC) have become more detailed and costly to comply with. At the same time, the OEB has become more aggressive in challenging our costs; as a result there is serious concern regarding our ability to recover the costs needed to sustain our assets. This risk may increase as a result of filing combined cost-of-service applications.

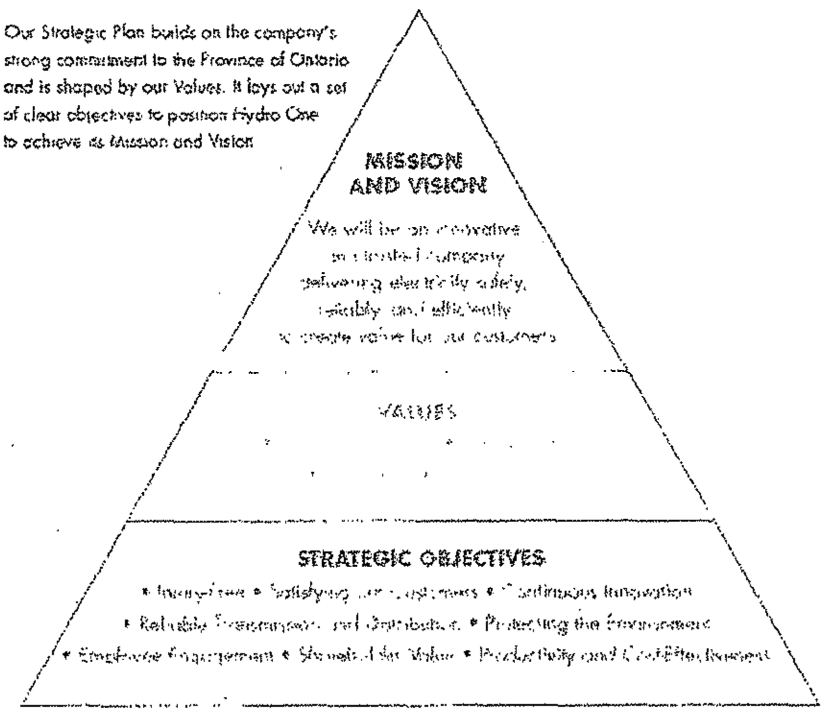
The OEB's *Framework for Transmission Development Plans* policy is being applied to the EWT project. There is concern that this new policy framework may erode our position as the primary builder and operator of Transmission assets in Ontario. To mitigate these risks, Hydro One will file comprehensive rate applications and develop a strategy, including entering into other partnerships, to obtain competitive projects.

The electricity delivery industry inherently carries a high risk to **worker safety**. In addition to instilling core health and safety values in new employees and apprentices, Hydro One continually stresses the importance of work safety audits, and implements safety initiatives such as Journey to Zero and OHSAS 18001. Safety targets continue to be aggressive, consistent with the belief that an Injury Free Workplace is the only acceptable result.

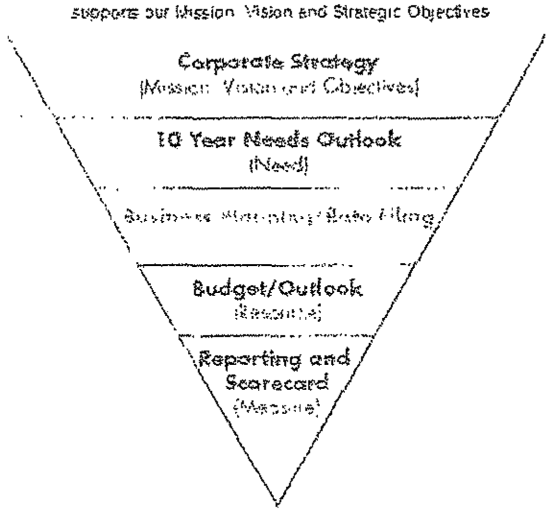
The Corporate Risk Profile reflects residual risk exposure of the largest credible sources of risk, after consideration of the mitigating controls in place or in progress. There are many other risks which are monitored within the Hydro One Enterprise Risk Management Policy and Framework.

HYDRO ONE STRATEGIC PLAN:
The Five-Year Mission and Vision (2012 – 2016)

Our Strategic Plan builds on the company's strong commitment to the Province of Ontario and is shaped by our Values. It lays out a set of clear objectives to position Hydro One to achieve its Mission and Vision



In planning and executing our work, everything we do supports our Mission, Vision and Strategic Objectives



Consumers Council of Canada (CCC) INTERROGATORY #2 List 1

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

Interrogatory

(Ex. A/T2/S 1/pp. 1-2) HONI is proposing to refund regulatory assets totalling $30.3 million over a two year period. Has this been factored into the proposed rate increases of .6% and 9%? If so, what are the rate increases without the regulatory assets rebate?

Response

Yes, the refund of regulatory assets over the 2013 and 2014 period have been factored into the rate increases of 0.6% and 9.1%, as shown in the response to interrogatory Exhibit I, Tab 2, Schedule 1.03 Staff 4.

The increases without the refund of the regulatory assets would be 1.7% in 2013 and 9.0% in 2014.

Consumers Council of Canada (CCC) INTERROGATORY #3 List 1

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

Interrogatory

(Ex. A/T8/S l/p. I) Please indicate ifHONI's corporate organization has changed since the 2011-2012 application. If it has changed, how has that impacted the revenue requirements?

Response

HONI's corporate organization has changed since the 2011-2012 application. The organizational changes were done to streamline decision-making at the executive level and enhance alignment within and between corporate and operational groups. There has been no impact to revenue requirement as a result of these organizational changes.

Consumers Council of Canada (CCC) INTERROGATORY #4 List 1

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

Interrogatory

(Ex. A/T13/S l/p. 2) The evidence indicates that with respect to planning that in November 2011 the HONI Board of Directors approved the 2012-2016 Business Plan. In April 2012 the HONI approved an "Updated" Business Plan. Please provide copies of the November 2011 Business Plan and the Updated Plan approved in Apri1 2012. Please indicate the extent there were any significant changes. If changes were made how have they impacted the 2013 and 2014 revenue requirements?

Response

Refer to Exhibit I Tab 2 Section 3.01 EP 01 part a) for the November 2011 and Updated April 2012 HONI Board Approved Business Plans.

Slide 12 in the ‘2012-14 Business Plan: April Update’ Presentation outlines the key updates from the November 2011 Business Plan. Changes denoted in slide 12 lowered revenue requirement by approximately $50M in 2013 and $70M in 2014 mainly due to the updated consensus forecast.

Consumers Council of Canada (CCC) INTERROGATORY #5 List 1

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

Interrogatory

(Ex. A/T17/S l/p. 1) HONI has cited that there is approximately $1 billion in aggregate savings of initiatives incorporated into its operations and embedded in the business plans along with ongoing operational efficiency improvements. Please provide a complete breakdown of the $1 billion.

Response

The y-axis of Figure 1 provides a partial breakdown of the over $1 billion in aggregate savings with the broad category of Consolidation representing approximately $700m in savings and Business Transformation providing over $550m. A further breakdown is provided below. Please note that the timeframe for the Business Transformation category extends well past the test years and out to the year 2020. As a result some of the values provided below are approximate and directional at this point in time. This analysis was derived from savings realized from the following categories:

Consolidation:
- Operational Efficiencies: ~$375m
- OGCC Consolidation: ~$160m
- LDC Consolidation: ~$150m
- Computer Aided Scheduling and Dispatch*: ~$20m

* The bubble related to this category in Exhibit A, Tab 17, Schedule 1, Figure 1 was presented in error. It should have been >$10 M.

Business Transformation:
- All Cornerstone Phases ~$280m
- Smart Grid ~$200m
- All Inergi Contracts ~$160m
- Smart Meter ~$100m
- Outsourcing ~$10m
- Standards ~$1m

Canadian Manufacturers & Exporters ("CME") INTERROGATORY #1 List 1

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

Interrogatory

Preamble

In prior proceedings, the Board has indicated that its approval of electricity infrastructure planning should take place with the Total Bill Impacts on consumers in mind. In prior proceedings, and most recently in the Renewed Regulatory Framework for Electricity ("RRFE") proceeding, CME and others sponsored and presented the year-over-year 5-year electricity price forecasts that electricity consumers are likely facing. The latest price increase forecast presented in the RRFE proceeding covers the period December 2011 to December 2016. The Report, dated March 21, 2012, was prepared by Bruce Sharp of Aegent Energy Advisors Inc. ("Aegent"). Its preparation was sponsored by CME, Consumers Council of Canada ("CCC"), Federation of Rental-housing Providers of Ontario ("FRPO"), School Energy Coalition ("SEC") and Vulnerable Energy Consumers Coalition ("VECC"). The Report can be found by following the link below, or by clicking on the RRFE link found under *"OEB Initiatives"* under *"Quick Links"* on the Ontario Energy Board's ("OEB") Home Page (bottom left-hand corner):

http://www.ontarioenergyboard.ca/OEB/_Documents/EB-2010-0377/CME_SUB_Ontario%20Elec%20Price%20Increase%20Forecast%202012.pdf

Ontario manufacturers are particularly sensitive to large year-over-year increases in their total electricity bills. Significant year-over-year total bill increases have a demand destruction potential that CME regards as material.

CME wishes to ascertain the extent to which Hydro One monitors the prospective year-over-year total electricity bill increases that consumers will likely be facing over the course of Hydro One's 5-year planning cycle, including the extent to which such price increases influence Hydro One's infrastructure planning and spending for the 2013 and 2014 test periods.

Questions

Having regard to the foregoing and in the context of the total bill impacts referenced, *inter alia*, at Exhibit A, Tab 2, Schedule 1 and at page 57 of Exhibit A, Tab 13, Schedule 2, where they are described as the "realities of rate impacts on customers", CME seeks the following further information from Hydro One:

(a) Please produce copies of any electricity price forecasts that Hydro One has in its possession that include the 2013 and 2014 test periods in the range of years covered by the forecast. CME seeks production of such price increase forecasts in Hydro One's possession that have been prepared by or on behalf of the OEB, the Minister of Energy, the Ontario Power Authority Inc. ("OPA"), Hydro One and/or Ontario Power Generation Inc. ("OPG").

(b) Please advise whether Hydro One accepts as reasonable the 5-year price increase forecasts faced by different categories of electricity consumers between December 2011 and December 2016, as described by Mr. Sharp in his Report dated March 21, 2012, as follows:

(i) Large consumers who qualify for a demand-related allocation of the Global Adjustment ("GA") and served directly off transmission are facing increases over the next 5 years totalling between 36% and 46%;

(ii) Similar large consumers served by LDC's are facing year-over-year increases for the next 5 years of between 39% and 48%;

(iii) Consumers who neither qualify for the demand-related allocation of the GA, nor the Ontario Clean Energy Benefit ("OCEB") are facing increases over the next 5 years totalling between 41% and 49%; and

(iv) The remaining customers, consisting primarily of residential consumers, are facing price increases over the next 5 years ranging between 46% and 58% assuming the discontinuance of the OCEB by 2016.

(c) As in prior cases, please produce, in confidence, unredacted copies of the presentations made to Hydro One's Board of Directors during the course of the planning process for this application referenced at Exhibit A, Tab 13, Schedule 1, page 2, including the written and slide presentations that provide Hydro One's Business Plans for the ensuing 5-years.

(d) Please provide a schedule that shows the year-by-year actual and forecasted transmission revenue requirement and rate increases for the period 2009 to 2014 inclusive.

(e) Having regard to the communications that Hydro One has with its customers referenced at Exhibit A, Tab 15, Schedule 2, pages 17 and18, please provide any information Hydro One has in its possession related to the level of total electricity bill increases to Ontario industrial consumers, including manufacturers, that are likely to trigger material demand destruction.

(f) Please produce the report pertaining to the prices in neighbouring jurisdictions referenced at Exhibit H1, Tab 5, Schedule 2, Appendix B at page 48 and provide any other information that Hydro One has in its possession that relates to the sensitivity of electricity consumers to significant year-over-year electricity price increases.

(g) What would be the impact on the proposed 2013 and 2014 spending plans, revenue requirements and transmission rate increases if the industrial production forecast at Exhibit A, Tab 15, Schedule 2 at page 6 for 2013 and 2014 was assumed to remain either flat or to decline for each of the two (2) years, rather than to grow by 4.2% in 2013 and 4.6% in 2014 respectively.

(h) Having regard to the totality of its spending plans for the next five (5) years, including Green Energy Plan ("GEP") spending plans reflected in Exhibit A, Tab 14, Schedule 1, please provide a schedule that shows the mix of renewable and non-renewable generation available and used to satisfy actual electricity demand in 2009 and the year-over-year changes in that mix that have occurred to date, along with the supply mix that Hydro One expects to be available and used to satisfy total electricity demand in Ontario by 2016, being the end of its current 5-year planning cycle.

(i) Making pricing assumptions that Hydro One considers to be reasonable, please provide a schedule that shows the approximate impact on the "all in" unit cost of electricity for General Service customers of the change in supply mix that will take place between 2009 and the end of Hydro One's current 5-year planning cycle in 2016. Use the General Service customers of Hydro One Distribution as the sample group for this particular calculation.

(j) What proportion of the 89 end-use customers shown in the Tables at Exhibit H1, Tab 2, Schedule 1, page 3 are classified by Hydro One as manufacturers.

Response

a) Hydro One is providing a summary of all price forecasts for the 2013 and 2014 time period that are available and in its possession. These forecasts are from three sources:

1. **Ontario Energy Board (OEB):** The two most recent Ontario Wholesale Electricity Market Price Forecast Reports prepared by Navigant Consulting on behalf of the OEB (April 2012 and October 2011) include price forecasts for the 2013 period. The reports can be found on the OEB website:
   http://www.ontarioenergyboard.ca/OEB/Industry/Regulatory+Proceedings/Policy+Initiatives+and+Consultations/Regulated+Price+Plan/Regulated+Price+Plan+(RPP)#20120419

2. **Ontario Ministry of Energy (MoE):** Section 7 of Ontario's Long Term Energy Plan prepared by the Ontario Ministry of Energy includes price projections for residential and industrial customers for the 2010-2030 time period. The report can be found on the MoE website:
   http://www.energy.gov.on.ca/en/ltep/

3. **Hydro One Networks:** The forecasted wholesale spot power prices for Ontario from IHS CERA Market Briefing Northeast Power Market Fundamentals, December 2011 are shown below.

Ontario Wholesale Spot Power Prices (Annual Average)
(nominal dollars per megawatt-hour)

Year	On-peak	Off-peak
2006	56.8	37.4
2007	60.3	36.9
2008	64.0	40.0
2009	37.3	25.3
2010	38.7	28.7
2011	36.5	27.9
2012	34.5	25.4
2013	36.6	23.7
2014	44.2	28.5
2015	45.9	28.9
2016	49.2	35.4

IHS CERA Market Briefing *Northeast Power Market Fundamentals,* December 2011.
Notes: On-peak is defined as Monday through Friday, 7:00 AM to 11:00 PM; off-peak is defined as Monday through Friday, 00:00 AM to 7:00 AM and 11:00 PM to 00:00 AM, and all day Saturday and Sunday.

b) Hydro One is unable to comment on the reasonableness of the 5-year price increase forecasts in Mr. Sharp's Report dated March 21, 2012 for the four categories of customers as described in parts i) to iv). Key assumptions presented in the appendix to the report are based on estimated values (i.e. capacity factors and various rates for generation additions; cost escalators and installed capacities for current generation; NUG prices and energy generation; 2011 CDM expenditure and CDM cost escalators; transmission and distribution cost escalators; increases for Wholesale Market Service Charges). Hydro One cannot verify how Mr. Sharp arrived at these estimates and as such cannot comment on the final results of the report.

c) Please refer to attachments to Exhibit I, Tab 2, Schedule 3.01 EP 1, part a)

d) The schedule below shows year-by-year OEB-approved and forecasted transmission revenue requirement and rate increases for the 2009 to 2014 periods. Please also see the response at Exhibit I, Tab 17, Schedule 13.01 AMPCO 11 for actual revenues.

	2009 Board Approved	**2010 Board Approved**	**2011 Board Approved**	**2012 Board Approved**	**2013 Forecast**	**2014 Forecast**
Revenue Requirement	1,179.0	1,257.3	1,345.6	1,418.4	1,464.5	1,557.7
Rate Increase	1.5%	9.2%	7.0%	7.8%	0.6%	9.1%

e) In reference to Exhibit A, Tab 15, Schedule 2, pages 17 and 18, Hydro One is not aware of any customers reporting material demand destruction due to the level of total electricity bill increases.

f) Please refer to Exhibit I, Tab 23, Schedule 1.02 Staff 85, Attachment 1

g) If the industrial production forecast in Exhibit A, Tab 15, Schedule 2, page 6 were assumed to remain flat in 2013 and 2014 the transmission rate increases would increase by 0.2% in 2013 (from 0.6% to 0.8%) and 0.4% in 2014 (from 9.1% to 9.5%). If the industrial forecast were to decline, an increase in rates proportionate to the impacts noted above is expected. A change in the industrial production forecast would have no impact on the spending plans or revenue requirements over the plan period.

h) Please see table below for a schedule of the mix of renewable and non-renewable generation by installed capacity and by capacity contribution to meet summer peak demand.

Schedule 1: **Generation Resources (Not Assuming Pickering Continued Operation)**

Installed Capacity by End of Year (MW)

Generation that is available at the end of the year (December).

	2009	2010	2011	2012	2013	2014	2015	2016
Renewables	9,722	10,151	11,016	11,408	12,631	16,586	18,015	18,543
Non-Renewables	27,352	26,278	25,287	27,400	26,407	25,232	24,702	19,911
Total	**37,074**	**36,429**	**36,304**	**38,808**	**39,038**	**41,818**	**42,718**	**38,455**

Capacity Contribution to Meet Summer Peak Demand (MW)

Generation that we can depend on to meet summer peak demand.

The summer by defined by the month of June, July and August.

	2009	2010	2011	2012	2013	2014	2015	2016
Renewables	6,189	6,246	6,473	6,600	6,894	7,465	7,881	8,393
Non-Renewables	24,735	25,815	23,722	24,665	25,358	23,383	22,422	20,097
Total	**30,923**	**32,061**	**30,196**	**31,265**	**32,252**	**30,848**	**30,303**	**28,490**

Yearly Changes (MW)

	2009	2010	2011	2012	2013	2014	2015	2016
Renewables	--	429	865	392	1,223	3,955	1,429	528
Non-Renewables	--	- 1,074	- 991	2,112	- 993	- 1,175	- 530	- 4,791
Total	--	**- 645**	**- 126**	**2,504**	**230**	**2,780**	**900**	**- 4,263**

Yearly Changes (MW)

	2009	2010	2011	2012	2013	2014	2015	2016
Renewables	--	57	227	127	294	571	416	512
Non-Renewables	--	1,080	- 2,092	943	693	- 1,974	- 961	- 2,325
Total	--	**1,137**	**- 1,865**	**1,070**	**986**	**- 1,403**	**- 545**	**- 1,814**

Source: OPA

Schedule 2: **Generation Resources (Assuming Pickering Continued Operation)**

Installed Capacity by End of Year (MW)

Generation that is available at the end of the year (December).

	2009	2010	2011	2012	2013	2014	2015	2016
Renewables	9,722	10,151	11,016	11,408	12,631	16,586	18,015	18,543
Non-Renewables	27,352	26,278	25,287	27,400	26,407	26,264	25,734	23,005
Total	**37,074**	**36,429**	**36,304**	**38,808**	**39,038**	**42,850**	**43,750**	**41,549**

Capacity Contribution to Meet Summer Peak Demand (MW)

Generation that we can depend on to meet summer peak demand.

The summer by defined by the month of June, July and August.

	2009	2010	2011	2012	2013	2014	2015	2016
Renewables	6,189	6,246	6,473	6,600	6,894	7,465	7,881	8,393
Non-Renewables	24,735	25,815	23,722	24,665	25,358	23,899	23,454	23,191
Total	**30,923**	**32,061**	**30,196**	**31,265**	**32,252**	**31,364**	**31,335**	**31,584**

Yearly Changes (MW)

	2009	2010	2011	2012	2013	2014	2015	2016
Renewables	--	429	865	392	1,223	3,955	1,429	528
Non-Renewables	--	- 1,074	- 991	2,112	- 993	- 143	- 530	- 2,729
Total	--	**- 645**	**- 126**	**2,504**	**230**	**3,812**	**900**	**- 2,201**

Yearly Changes (MW)

	2009	2010	2011	2012	2013	2014	2015	2016
Renewables	--	57	227	127	294	571	416	512
Non-Renewables	--	1,080	- 2,092	943	693	- 1,458	- 445	- 263
Total	--	**1,137**	**- 1,865**	**1,070**	**986**	**- 887**	**- 29**	**248**

Notes

- Renewable generation includes hydroelectric, bioenergy, wind and solar.
- Non-Renewables generation includes nuclear, coal, gas/oil, and demand response.
- In 2016, the amount of non-renewable generation that we can depend on is expected to be available during the summer months, but will not be available by the end of the year, as this amount of generation is expected to come offline in the fall. As a result, the capacity contribution to meet summer peak demand by 2016 is greater than the amount that is availble by the end of the year.

Source: OPA

i) Hydro One does not forecast the impact on electricity prices as a result of changes in supply mix.

j) Approximately 80% of the 89 end-use customers are manufacturers based on the North American Industry Classification System (NAICS).

Ontario Energy Board (Board Staff) INTERROGATORY #16 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

Ref: Exhibit A/Tab 15/Sch 1
The forecasts for Ontario CPI and Cost Escalation appear to be more recent than in Exhibit 13, dated February 2012 and January 2012. Have more recent forecasts been released? If so, please provide these forecasts and also indicate if the changes in the forecasts are material and how the application would be affected.

Response

The latest forecasts from Global Insight for Ontario CPI (released in June 2012) and Cost Escalation (released in August 2012) are provided below. The changes in the forecasts are immaterial and do not impact this application.

	Historic			**Bridge**	**Test**	
	2009	**2010**	**2011**	**2012**	**2013**	**2014**
CPI-Ontario (%)	0.4	2.4	3.1	2.0	2.2	1.9
Transmission Cost Escalation for Construction (%)	-2.6	1.9	3.7	2.3	2.5	2.3
Transmission Cost Escalation for Operations & Maintenance (%)	-0.1	1.6	3.6	2.3	2.4	2.4

Ontario Energy Board (Board Staff) INTERROGATORY #17 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

Ref: Exhibit A/Tab 15/Sch1/p 4
Please update the forecast for Allowance for Funds Used During Construction using the most recently available Consensus Forecast

Response

Table 1 be low shows the updated forecast for Allowance for Funds Used During Construction using the August 2012 Consensus Forecast (for 2012 and 2013) and the April Bank of Canada Long-term Forecast (for 2014). However, as noted in the footnote to Exhibit A, Tab 15, Schedule 1, p.4, the appropriate rate to use is the Interest Capitalization rate, which is shown in Exhibit D1, Tab 2, Schedule 1.

Table 1

	Bridge	**Test**	
	2012	**2013**	**2014**
10-year Government of Canada %	1.80	2.05	3.60
All Corporate Mid-Term Bond Spread	1.52	1.52	1.52
CWIP Account Rate %	3.32	3.57	5.12

Ontario Energy Board (Board Staff) INTERROGATORY #18 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

Ref: Exhibit A/Tab 15/Sch2/Table 3
This table shows that Ontario Demand (before deducting impacts of Embedded Generation and CDM) grows by 0.9% in 2012, 1.3% in 2013 and 1.3% in 2014. At pages 5 and 6 of this same exhibit it appears that Provincial GDP and particularly Industrial Production are forecast to grow at much higher rates. Given the latter, why is the demand forecast so low?

Response

Ontario demand reflects the peak load of all customers in Ontario. As shown in the table below, Ontario demand before deducting impacts of embedded generation and CDM has been growing slower than Ontario GDP historically. The forecast for Ontario demand in Table 3 of Exhibit A, Tab 15, Schedule 2 reflects this relationship and the economic recovery of our industrial customers over the forecast period.

Ontario GDP vs. Ontario 12-Month Average Peak Demand:
Comparison of Average Annual Growth Rates for Historical and Forecast Periods

	Historical (1999-2011)	Forecast (2012-2014)
Ontario GDP	2.3%	2.3%
Ontario 12-Month Average Demand	0.9%	1.2%
Difference	1.4%	1.1%

Ontario Energy Board (Board Staff) INTERROGATORY #19 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

Ref: Exhibit A/Tab 15/Sch2/p 8
Hydro One indicates that its forecast CDM peak impacts are consistent with the Long-Term Energy Plan released by the Ontario Government in November 2010 with a provincial target of achieving peak savings of 4,550 MW by 2015 and 7,100 MW by 2030. The CDM savings information is provided in ExhibitA-15-2/Attachment 1/AppendixA. Did Hydro One analyse the information provided on a program by program basis to determine whether the CDM targets could be met in the test years? What level of confidence does Hydro One have in the OPA CDM targets which were incorporated in the forecast? Please provide any analysis conducted on the CDM targets to determine their achievability.

Response

Hydro One did not analyze the information provided by the OPA on a program by program basis to determine whether the CDM targets could be met in the test years. As documented in Attachment 1 of Exhibit A, Tab 15, Schedule 2, Hydro One worked closely with the OPA to derive the CDM impacts used in this rate application.

Hydro One is working with the OPA on establishing new CDM programs and Hydro One believes that the 4- year LDC CDM targets for Hydro One are achievable. Hydro One believes that the OPA is monitoring progress for all LDCs in the province. The OPA has not communicated to Hydro One that the CDM targets are not achievable. Hydro One has not undertaken any analysis to determine the achievability of the provincial CDM targets.

Ontario Energy Board (Board Staff) INTERROGATORY #20 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

Ref: Exhibit A/Tab 15/Sch2/Table 5
In this table, for 2010 a larger than typical variance of 1.00% is shown for Peak Demand. What are the reasons for this variance in 2010?

Response

The forecast for the average monthly peak demand in 2010 was 20,891 MW and the weather corrected actual was 20,684 MW, which resulted in a 1% variance of the forecast being higher than the actual. The main reasons for this variance can be attributed to the slow economic recovery from the severe 2008-2009 recession and the impacts of CDM programs. The 1% variance is within one standard deviation (1.77%) of the forecast.

Ontario Energy Board (Board Staff) INTERROGATORY #21 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

Ref: Exhibit A-15-2/Attachment 1/p 74
Under E.5 Comparison of the Three Methods, Hydro One cites two specific challenges for Method 3. Please show how Hydro One addressed/overcame those challenges to determine that Method 3 should be chosen.

Response

As documented in Attachment 1 of Exhibit A, Tab 15, Schedule 2, the two challenges associated with Method 3 pertain to getting accurate CDM impacts for both the historical and forecasted periods. Hydro One has addressed and overcome these two challenges by using the provincial CDM impacts provided by the OPA for the historical and forecasted periods. Using Method 3, Hydro One is able to explicitly account for historical and forecasted CDM impacts and use consistent historical data for the regression analysis.

Ontario Energy Board (Board Staff) 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

Ref: Exhibit A-15-2/Attachment 1/p 75
Hydro One indicates that Method 3 is 'technically sound and efficient'. Please provide the specific reasons for this.

Response

Method 3 is considered "technically sound and efficient" because only this method, of the three methods, generates unbiased and efficient estimates of regression coefficients and forecasts from the perspective of statistical analysis as compared to Method 1 a nd Method 2.

London Property Management Association (LPMA) INTERROGATORY #2 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

Ref: Exhibit A, Tab 15, Schedule 2

a) Please expand Table 3 to reflect actual data starting in 2007.

b) Please provide a version of Table 3 that shows the averages based on the months currently available for 2012, along with the averages for the same period in 2011.

Response

The requested information is provided in the following tables;

Table 3 Expanded to Include Actual for 2007-2011
Load Forecast Before and After Embedded Generation and CDM
(12-Month Average Peak in MW)

		Charge Determinant		
Year	Ontario Demand (MW)	Network Connection (MW)	Line Connection (MW)	Transformation Connection (MW)
Load Forecast before Deducting Impacts of Embedded Generation and CDM				
2007	22,604	22,028	20,971	18,131
2008	22,803	22,269	21,148	18,271
2009	22,666	22,167	20,841	18,249
2010	22,155	21,777	20,477	17,823
2011	22,498	22,164	20,944	18,089
2012	22,696	22,359	21,128	18,248
2013	23,003	22,662	21,415	18,495
2014	23,309	22,963	21,699	18,741
Load Impact of Embedded Generation				
2007	146	143	10	10
2008	179	176	10	10
2009	211	208	10	10
2010	275	271	10	10
2011	346	337	10	10
2012	467	455	10	10
2013	538	524	10	10
2014	568	554	10	10
Load Impact of CDM				
2007	982	957	917	792
2008	1,051	1,026	982	848
2009	1,115	1,090	1,034	906
2010	1,196	1,176	1,119	974
2011	1,605	1,582	1,517	1,310
2012	1,890	1,862	1,760	1,520
2013	2,147	2,115	1,998	1,726
2014	2,899	2,856	2,699	2,331
Load Forecast after Deducting Embedded Generation and CDM				
2007	21,476	20,928	20,044	17,329
2008	21,574	21,067	20,156	17,413
2009	21,340	20,868	19,796	17,333
2010	20,684	20,330	19,348	16,839
2011	20,547	20,245	19,417	16,769
2012	20,339	20,042	19,359	16,718
2013	20,319	20,023	19,406	16,759
2014	19,841	19,552	18,990	16,400

Note. All figures are weather-normal.

Table 3 Updated to include Estimates for June 2012
Load Forecast Before and After Embedded Generation and CDM
(6-Month Average Peak in MW)

		Charge Determinant		
Year	Ontario Demand (MW)	Network Connection (MW)	Line Connection (MW)	Transformation Connection (MW)
Load Forecast before Deducting Impacts of Embedded Generation and CDM				
2011	22,152	21,681	20,351	17,576
2012	22,193	21,814	20,568	17,699
Load Impact of Embedded Generation				
2011	346	338	10	10
2012	467	459	10	10
Load Impact of CDM *				
2011	1,499	1,467	1,399	1,208
2012	1,759	1,728	1,664	1,432
Load Forecast after Deducting Embedded Generation and CDM				
2011	20,307	19,875	18,942	16,358
2012	19,968	19,627	18,894	16,258

Note.
(1) All figures are weather-normal.
(2) There is more CDM impact during the summer compared to other months. Consequently, January- June average CDM impact presented in this table exceeds 12-month average.
(3) CDM values provided are based on forecast and not actual.

London Property Management Association (LPMA) INTERROGATORY #3 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

Ref: Exhibit A, Tab 15, Schedule 2, Appendix E

a) Please update the forecasts shown to reflect the most recent forecasts from each of the sources shown.

b) What is the impact on the forecasts for 2013 and 2014 based on the updated forecasts requested in part (a) above?

Response

a) Please see the response to Exhibit I, Tab 2, Schedule 3.06 EP 6 part c).

b) Since the updated GDP forecasts for 2013 and 2014 are lower, it would result in slightly lower load forecast for 2013 and 2014.

London Property Management Association (LPMA) INTERROGATORY #4 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

Ref: Exhibit A, Tab 15, Schedule 2, Appendix F

a) For each rate case shown in the tables (i.e. EB-2006-0501, EB-2008-0272 and EB-2010-0002) please indicate which years were the test years.

b) Please provide a set of tables that show the forecast, the actual weather corrected and the % difference for the first test year from each of the applications shown for each of Tables 6a, 6b and 6c. Please also provide a second set of tables that show the same information for the second test year from each of the applications shown for each of Tables 61, 6b and 6c.

Response

a) The requested information is provided below:

- For EB-2006-0501, the test years are 2007 and 2008;
- For EB-2008-0272, the test years are 2009 and 2010;
- For EB-2010-0002, the test years are 2011 and 2012.

b) The requested information is provided in the following 3 tables:

Table 6a Rearranged
Comparison of Network Connection Forecast with Weather Corrected Actual

Rate Application	Forecast	Actual: Weather Corrected	Difference (%)
For the first test year			
EB-2006-0501	20,827	20,928	-0.48
EB-2008-0272	20,842	20,868	-0.13
EB-2010-0002	20,150	20,245	-0.47
Average			-0.36
For the second test year			
EB-2006-0501	20,872	21,067	-0.92
EB-2008-0272	20,199	20,330	-0.64
EB-2010-0002	n.a.	n.a.	n.a.
Average			-0.78

Table 6b Rearranged
Comparison of Line Connection Forecast with Weather Corrected Actual

Rate Application	Forecast	Actual: Weather Corrected	Difference (%)
For the first test year			
EB-2006-0501	19,875	20,044	-0.84
EB-2008-0272	20,100	19,796	1.53
EB-2010-0002	19,500	19,417	0.42
Average			0.37
For the second test year			
EB-2006-0501	19,940	20,156	-1.07
EB-2008-0272	19,555	19,348	1.07
EB-2010-0002	n.a.	n.a.	n.a.
Average			0.00

Table 6c Rearranged
Comparison of Transformation Connection Forecast
with Weather Corrected Actual

Rate Application	Forecast	Actual: Weather Corrected	Difference (%)
For the first test year			
EB-2006-0501	17,086	17,329	-1.40
EB-2008-0272	17,376	17,333	0.25
EB-2010-0002	16,850	16,769	0.48
Average			-0.22
For the second test year			
EB-2006-0501	17,142	17,413	-1.56
EB-2008-0272	16,905	16,839	0.39
EB-2010-0002	n.a.	n.a.	n.a.
Average			-0.59

London Property Management Association (LPMA) INTERROGATORY #5 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

Ref: Exhibit A, Tab 15, Schedule 1, Attachment 1

Hydro One has a forecast of CDM impacts on the charge determinants shown in Table 3. Does Hydro One believe it should an LRAM variance account based on these forecasted figures which are built into the forecast? If not, why not?

Response

The above reference should read Exhibit A, Tab 15, Schedule 2, Attachment 1.

Hydro One does not believe it should have an LRAM variance account on CDM impacts for this rate application because critical Evaluation, Measurement and Verification (EM&V) results for CDM savings pertaining to codes and standards and other influences are not available.

Energy Probe (EP) INTERROGATORY #8 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

Ref: Exhibit A, Tab 15, Schedule 2, Page 9 &
Exhibit A, Tab15, Schedule 2, Attachment 1 A.1, Tables 4-9

a) With respect to Page 9, Table 2 please provide the load forecast as filed in EB-2010-0002 for 2011 and please provide:
   i) 2011 actual load and
   ii) CDM impact for 2011-2012.YTD plus estimate.

b) Please provide a copy of OPAs latest CDM projections for the test years.

c) Are Hydro One's projected CDM impacts consistent with the OPA's latest outlook? In responding please provide details for the OPA CDM projections for each year through to 2015, contrast/compare with Hydro One's CDM impact forecast for 2011 through 2014 and explain any differences.

d) What other variables in the econometric forecast are affected by CDM reductions? Please list and discuss if the models are rerun for these effects (loads/demand, line losses etc).

Response

a)
   i. The table below presents the 2011 load forecast (12-month average peak of Ontario demand in MW) approved in EB-2010-0002 and the 2011 weather corrected actual as presented in EB-2012-0031.

Year	Forecast (12-month avearge in MW) EB-2010-0002	Weather Corrected Actual (12-month avearge in MW) EB-2012-0031
2011	20,613	20,547

   ii. The table below presents the 2011 and 2012 CDM impacts approved in EB-2010-0002 and latest CDM impacts provided by the OPA as presented in EB-2012-0031. Please note the latest 2011 and 2012 CDM impacts should be considered as forecast because actuals are not available.

	EB-2010-0002 Forecast		EB-2012-0031 Forecast	
	Cumulative CDM impact Peak Demand	Cumulative CDM impact 12-month Average Peak Demand	Cumulative CDM impact Peak Demand	Cumulative CDM impact 12-month Average Peak Demand
2011	2,486	2,138	2,351	1,605
2012	3,064	2,628	2,749	1,890

b) The latest CDM projections for the test years from the OPA are provided in pages 24-25 in Attachment 1 of Exhibit A, Tab 15, Schedule 2.

c) Yes, it is confirmed that Hydro One used the latest forecast of CDM impacts from the OPA in this rate application. Please see the response to (b) for the CDM impacts provided by the OPA.

d) The only variable affected by the CDM impacts in the econometric model is the actual load. No other variables in the econometric model are affected by the CDM impacts. Hydro One adds back the CDM impacts to the actual load for the historical period before running the regression to ensure the relationship between the load (left-hand-side variable) and explanatory variables such as economic factors (right-hand-side variables) in the regression model is not distorted by the CDM impacts over the historical and forecast periods. Using this approach, there is no need to rerun the model for the CDM effects. For detailed discussion on methods of incorporating CDM in the load forecast, please see Pages 63-73, Appendix E in Attachment 1 of Exhibit A, Tab 15, Schedule 2.

Energy Probe (EP) INTERROGATORY #9 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

Ref: Exhibit A, Tab 15, Schedule 2 &
Exhibit A, Tab 15, Schedule 2, Tables ES1 and Tables A1 4-9 &
Exhibit A, Tab 15, Schedule 2, Table 15

a) Please describe in some detail the methodology used to go from the OPA 2012-2015 data (2,749; 3,292; 4,186; 4,590 MW) to the CDM impacts in ES1.

b) How does Hydro One map the OPA CDM results to its service area and delivery points? Describe the adjustments made to the historic and forecast data.

c) Please outline what historical years' data were used to test each of the CDM forecasting methods.

d) What modeling/tests of the three methods in Table 15 did Hydro One perform and what were the results of the three methods in terms of accuracy of the forecast(s)?

Response

a) Detailed description of the methodology used to derive the CDM impacts from the OPA data is provided in pages 18-30 in Exhibit A, Tab 15, Schedule 2, Attachment 1.

b) Hydro One maps the OPA CDM impacts to its service area using the charge determinants applicable to Hydro One.
Hydro One uses the following allocation methodology to map the CDM impacts to each delivery point (DP):

- Total annual CDM impacts (energy and peak) were assigned to each individual LDC and TX-connected industrial customer using their respective energy and peak share.
- CDM (energy and peak) impacts by DP are calculated as:

$$\text{CDM impacts for the customer} * \frac{\text{Energy/peak share of the customer for that DP}}{\text{Total energy/peak of the customer}}$$

As discussed in Exhibit A, Tab 15, Schedule 2, Attachment 1, Appendix E, Hydro One uses Method 3 to incorporate CDM impacts in the load forecast. Hydro one adjusts historical load by adding back CDM impacts to yield a consistent data set over time for modeling and deducts historical and forecasted CDM impacts from the gross load forecast.

c) Hydro One used 2005-2011 monthly data of Ontario demand to test the 3 methods.

d) Regression analysis was undertaken to test the statistical properties of the 3 methods discussed in Table 15. Key findings of the regression analysis undertaken by Hydro One are summarized below:
   - Method 1 shows a negative coefficient for the GDP variable;
   - Method 2 has multi-collinearity issues; and
   - Method 3 yields unbiased and efficient coefficients.

Hydro One did not use the above analysis to check the forecast accuracy of the 3 methods.

Energy Probe (EP) INTERROGATORY #10 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

Ref: Exhibit A, Tab 15, Schedule 2, Figures 3&4

a) Please discuss how Pearson Airport data are used to derive the individual loads at the delivery points (weighting etc).

b) Are line losses modeled/corrected for in the weather normalization? If not, why not. If so, please describe how this is done.

Response

a) In addition to Toronto Pearson International Airport weather data, 4 other weather stations in Ontario (Ottawa, North Bay, Thunder Bay and Windsor) are used in preparing the weather normalization analysis by delivery point. Each delivery point is assigned to closest weather station noted above.

b) Transmission line losses are modeled and weather normalized as part of the Ontario demand. Distribution line losses associated with each delivery point are modeled and weather normalized as part of the load at that delivery point. There is no separate model/weather normalization associated with line losses.

Vulnerable Energy Consumers Coalition (VECC)INTERROGATORY #15 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, pages 2 (1. 15) and 13 (Section 4.1.2)

a) Have any of the neighbouring utilities that Hydro One interacts with and/or is familiar with changed their period for weather normalization since 2008? · If yes, please indicate which utilities and the nature of the change.

Response

a) Hydro One is not aware of any neighbouring utilities that have changed their period for weather normalization since 2008.

Vulnerable Energy Consumers Coalition (VECC)INTERROGATORY #16 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, page 5 and Appendix E

a) Please update the surveys of Ontario GOP Forecasts and Ontario Housing Starts using the most recent forecasts available from each source noted.

Response

a) Please see the response to Exhibit I, Tab 2, Schedule 3.06 EP 6, part c).

Vulnerable Energy Consumers Coalition (VECC)INTERROGATORY #17 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, pages 9- 10

a) The text states that 346 MW of self-generation was assumed to be in place in 2011. What was the actual amount of self-generation in-place in 2011 and how does this compare with the amount in place in 2009 and 2010?

b) Please confirm that the 346 MW of self-generation for 2011 is all "behind the meter" (i.e., the self-generation that reduces the amount purchased from the IESO) ..

c) The text states that the incremental self-generation assumed for 2012- 2014 is based on renewable energy projects initiated by the OPA. Are these projects where the OPA is buying the renewable generation from the customers?

d) If yes, why is it considered "behind the meter" generation that will reduce transmission billing determinants?

Response

a) Hydro One does not have the actual amount of embedded generation by-pass (self-generation that reduces the amount purchased from the IESO) for 2011 and the amount of embedded generation by-pass in 2011 was estimated to be 346 MW. The actual amount of embedded generation for 2009 and 2010 is estimated to be 211 MW and 275 MW respectively.

b) It is confirmed that the 346 MW of embedded generation projects for 2011 are connected directly to the distribution system (or as referred to in this Interrogatory as “behind the meter”) and hence do not pay transmission network charges.

c) Yes. However, it should be noted that some of these renewable projects will be connected directly to the transmission grid and some projects will be connected directly to the distribution system.

d) As mentioned in c), some of these embedded generation projects will be connected directly to the distribution system.

Vulnerable Energy Consumers Coalition (VECC)INTERROGATORY #18 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, pages 8-9

a) Please confirm whether the data reported for years 2006-2011 in Table 2 is the actual weather normalized impact of CDM in those years.

b) What is the starting year from which the results shown in Table 2 are "cumulative"?

Response

a) Yes, the CDM impact reported for years 2006-2011 in Table 2 is weather normalized. The 2006-2010 CDM impact provided by the OPA includes actual for those programs with EM&V results and estimates for those programs without EM&V results. The 2011 CDM impact is a forecast because the final 2011 EM&V results of LDC CDM programs will only be available in August/September 2012.

b) 2006

Vulnerable Energy Consumers Coalition (VECC)INTERROGATORY #19 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, page 21

a) At what point on the system are the Ontario Demand values and the Charge Determinant values set out in Table 3 (page 21) measured?

b) Please provide a monthly break down for each of 2013 and 3014 for each of the four forecasts set out in the Table.

Response

a) The Ontario Demand is measured at the generation level and the Charge Determinants are measured at the transmission delivery point level.

b) The requested information (monthly breakdown of load forecast after deducting embedded generation and CDM) is provided in the following table.

Forecast of Ontario Demand and Charge Determinants
(MW)

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2013												
Ontario Demand	21,622	21,549	20,425	17,921	18,201	20,973	22,319	21,302	20,503	18,252	19,693	21,064
Network Connection	20,776	21,309	20,155	18,030	17,550	20,592	22,432	20,871	20,075	18,276	19,236	20,972
Line Connection	20,099	20,335	19,790	18,059	17,100	20,160	21,400	20,167	19,111	18,146	18,713	19,794
Transformation Connection	17,649	17,780	16,899	15,247	14,768	17,409	18,776	17,457	16,517	15,423	15,926	17,258
2014												
Ontario Demand	21,290	21,263	20,168	16,992	17,335	20,468	21,818	20,820	20,162	18,061	19,023	20,691
Network Connection	20,522	21,090	19,962	17,148	16,662	20,035	21,863	20,336	19,680	18,030	18,638	20,664
Line Connection	19,886	20,160	19,636	17,231	16,289	19,658	20,899	19,693	18,774	17,939	18,176	19,539
Transformation Connection	17,461	17,626	16,766	14,547	14,068	16,974	18,335	17,046	16,225	15,246	15,468	17,034

Nore. All figures are weather-normal.

Vulnerable Energy Consumers Coalition (VECC)INTERROGATORY #20 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 13-14

a) Please indicate into which of Hydro One's three CDM categories (per page 13) each of the six categories of CDM listed on page 14 fall.

Response

a) The requested mapping is provided below.

Categories used in the survey	Categories used in Hydro One's transmission load forecast
Energy efficiency programs	Programs
Appliance and lighting efficiency standards	Codes and Standards
Building codes	Codes and Standards
Demand management programs	Programs
Time-of-Use prices or dynamic pricing	Pricing
Customers' conservation actions (not captured by specific programs)	Not used

Vulnerable Energy Consumers Coalition (VECC)INTERROGATORY #21 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, S chedule 2, page 20 EB-2012-0033, Technical Conference July 31, 2012, page 137, lines 13-22

Preamble: The text states that Hydro One obtained province-wide CDM savings from the OPA. It is noted (see second reference above) that the OPA reports annualized CDM savings and therefore its reports will overstate the actual impact of CDM in the year that a program is implemented.

a) Is Hydro One aware of the OPA's approach to reporting CDM savings for the programs in the year they are initiated?

b) Has Hydro One adjusted the reported savings (both historical and forecast) to account for this reporting approach?

c) If yes, how was it done?

d) If no, what is the impact of correcting for this on the forecast COM savings for 2013 and 2014?

Response

a) Yes.

b) No, Hydro One has not made any adjustments to the CDM savings (both historical and forecast) provided by the OPA in this rate application because there is no need to make any adjustments. EB-2012-0033 Technical Conference July 31, 2012, page 137, lines 13-22 pertain to the EM&V results of actual CDM program savings achieved by Enersource in 2011. T he CDM forecast savings provided by the OPA for use by Hydro One in its load forecast for the years 2011-2014 in this rate application requires no a djustments because the CDM forecast has taken the expected EM&V results from all LDCs into consideration in order to meet the CDM targets set by the Government of Ontario.

c) See response to b).

d) See response to b).

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

Vulnerable Energy Consumers Coalition (VECC)INTERROGATORY #23 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

Preamble: At step 5 (page 21), Hydro One states that the impact of CDM on each of the three charge determinants was calculated by multiplying the monthly CDM savings for Ontario with the ratio of gross forecast for charge determinant and Ontario demand.

a) Please provide an illustrative calculation using January 2013. In doing so. please clarify whether the "monthly CDM savings" referred to are monthly peak savings or monthly energy savings.

Response

The “monthly CDM savings” referred to are monthly peak savings.

The following provides an illustrative calculation of Step 5 using CDM demand saving (MW) for charge determinants in January 2013:

Step 5(a): Use Ontario Monthly peak saving in the following table.

Month	CDM Demand saving (MW)
Jan 2013	2,190

Step 5(b): Calculate ratios of gross demand of each charge determinant to that of Ontario demand in Jan 2013

		Charge Determinant		
	Ontario Demand	Network Connection	Line Connection	Transformation Connection
Gross load forecast (MW)	24,350	23,398	22,097	19,404
Ratio (charge determinant/Ontario demand)		96%	91%	80%

Step 5(c): The impact of CDM on each of the three charge determinants is calculated by multiplying the CDM demand saving in MW for Ontario (Step 1) with the ratio of gross forecast for charge determinant and Ontario demand in Jan 2013 (Step 2).

		Charge Determinant *		
	Ontario Demand	**Network Connection**	**Line Connection**	**Transformation Connection**
CDM Demand saving (MW) in Jan 2013	2,190	2,104	1,987	1,745

** CDM for Network Connection= 2,190 * 96%=2,104*
** CDM for Line Connection= 2,190 * 91%=1,987*
** CDM for Transformation Connection= 2,190 * 80%=1,745*

Vulnerable Energy Consumers Coalition (VECC)INTERROGATORY #24 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, Appendix D

a) Please explain what is meant by the table footnote- "Charge determinant values are proxy numbers calculated based on actual data".

b) Please reconciled the 2011 maximum Ontario Demand value reported here (22,728 MW- July Weather Normalized) with the actual2011 Ontario Demand reported at Exhibit A, Tab 15, Schedule 2, Table 3 (20,547 MW). If the difference is losses, please explain the point of measurement used for each set of data and provide the loss factor that should be used to reconcile the two tables.

c) Please confirm that the average of the (2011 weather normalized) monthly values for the various charge determinants (as reported in Appendix D) reconciles with the values report in Exhibit A, Tab 15, Schedule 2, Table 3.

d) Please provide a table similar to that in Appendix D for the years 2012- 2014. Please reconcile any differences between the maximum Ontario Demand for each year as reported in this response versus that in Exhibit A, Tab 15, Schedule 2, Table 3.

e) Please provide a schedule that for the years 2010-2014 sets out the peak load by region by month (i.e, the maximum demand for the region in each month). Please also indicate where on the system the peak load values are deemed to be measured (e.g. regional bus, point of generation, etc.).

f) Please provide a schedule that for the years 2010-2014 sets out the demand for each region at the time of the system peak. Please ensure that the basis for these values (in terms of the point on the system where the load is deemed to be measured) is the same as that used in response to part (e).

Response

a) The footnote in Appendix D means the charge determinant values for the historical year are estimated based on actual load. Hydro One uses the term "proxy numbers" because they are not actual charge determinants but rather estimated charge determinants based on actual historical data.

b) 22, 728 MW pertains to the 2011 maximum Ontario Demand for the month of July, while 20,547 MW pertains to the 12-month average peak of Ontario Demand for the year 2011.

c) Yes, it is confirmed that average of the (2011 weather normalized) monthly values for various charge determinants (as reported in Appendix D) reconciles with the values reported in Exhibit A, Tab 15, Schedule 2, Table 3.

d) The monthly forecast for Ontario Demand and Charge Determinants are provided in the following Table. The 12-month average of these figures, are presented in Exhibit A, Tab 15, Schedule 2, Table 3.

Forecast of Ontario Demand and Hydro One Transmission Charge Determinants
(MW)

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2012												
Ontario Demand	21,650	21,529	20,420	17,860	17,993	21,140	22,507	21,443	20,527	18,159	19,723	21,114
Network Connection	20,740	21,223	20,088	17,911	17,403	20,818	22,686	21,074	20,159	18,235	19,207	20,957
Line Connection	20,001	20,191	19,661	17,876	16,895	20,310	21,575	20,293	19,125	18,041	18,620	19,716
Transformation Connection	17,562	17,654	16,788	15,093	14,592	17,538	18,928	17,566	16,529	15,332	15,846	17,189
2013												
Ontario Demand	21,622	21,549	20,425	17,921	18,201	20,973	22,319	21,302	20,503	18,252	19,693	21,064
Network Connection	20,776	21,309	20,155	18,030	17,550	20,592	22,432	20,871	20,075	18,276	19,236	20,972
Line Connection	20,099	20,335	19,790	18,059	17,100	20,160	21,400	20,167	19,111	18,146	18,713	19,794
Transformation Connection	17,649	17,780	16,899	15,247	14,768	17,409	18,776	17,457	16,517	15,423	15,926	17,258
2014												
Ontario Demand	21,290	21,263	20,168	16,992	17,335	20,468	21,818	20,820	20,162	18,061	19,023	20,691
Network Connection	20,522	21,090	19,962	17,148	16,662	20,035	21,863	20,336	19,680	18,030	18,638	20,664
Line Connection	19,886	20,160	19,636	17,231	16,289	19,658	20,899	19,693	18,774	17,939	18,176	19,539
Transformation Connection	17,461	17,626	16,766	14,547	14,068	16,974	18,335	17,046	16,225	15,246	15,468	17,034

e) The monthly figures for regional peak are provided in the following table, and are measured at delivery point level.

Monthly Regional Peak at Delivery Point Level
(MW)

Year/Regic	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2010												
Central	10,914	10,802	10,227	9,232	9,675	11,466	12,243	11,450	10,957	9,358	9,804	10,880
East	3,357	3,224	2,848	2,511	2,587	2,906	3,254	3,047	2,913	2,529	2,889	3,256
Northeast	1,221	1,226	1,192	1,128	852	1,025	970	998	927	1,145	1,178	1,248
Nonthwest	517	564	567	505	394	475	457	439	455	577	586	640
Southwest	4,701	4,623	4,460	4,074	4,040	5,178	5,402	5,157	4,825	4,123	4,384	4,696
2011												
Central	10,797	10,847	10,201	9,151	9,473	11,307	12,173	11,554	10,703	9,279	10,139	10,853
East	3,455	3,242	3,036	2,580	2,367	2,761	3,088	2,881	2,725	2,532	2,834	3,251
Northeast	1,277	1,242	1,201	1,101	862	905	918	1,091	1,051	1,093	1,109	1,301
Nonthwest	654	643	616	581	457	469	453	543	513	615	614	687
Southwest	4,651	4,617	4,431	4,021	4,278	4,999	5,287	4,970	5,043	4,059	4,435	4,810
2012												
Central	10,514	10,984	10,198	9,219	9,784	11,117	12,272	11,098	10,470	9,466	9,850	10,661
East	3,248	3,269	3,135	2,443	2,365	2,947	3,066	2,987	2,703	2,509	2,911	3,288
Northeast	1,161	1,204	1,135	969	855	801	897	973	1,022	976	1,036	1,145
Nonthwest	645	635	636	561	508	465	481	531	566	602	618	630
Southwest	4,638	4,696	4,348	3,877	3,709	4,980	5,415	4,914	4,731	4,396	4,424	4,692
2013												
Central	10,531	11,028	10,231	9,280	9,869	11,000	12,135	10,993	10,427	9,487	9,866	10,668
East	3,253	3,282	3,145	2,459	2,385	2,916	3,032	2,958	2,692	2,515	2,915	3,290
Northeast	1,163	1,209	1,139	976	863	793	887	963	1,018	978	1,037	1,146
Nonthwest	646	637	638	565	513	460	476	526	563	604	619	630
Southwest	4,645	4,715	4,362	3,903	3,741	4,927	5,355	4,867	4,712	4,406	4,431	4,695
2014												
Central	10,462	10,971	10,187	9,318	8,881	10,759	11,876	10,763	10,286	9,404	9,639	10,749
East	3,214	3,245	3,112	2,340	2,459	2,832	2,782	2,848	2,638	2,480	2,830	3,101
Northeast	1,110	1,159	1,092	879	831	742	850	896	961	934	951	1,066
Nonthwest	615	610	613	508	492	428	445	504	532	574	568	571
Southwest	4,580	4,658	4,317	3,709	3,809	4,785	5,209	4,849	4,610	4,344	4,275	4,450

f) The monthly figures for regional peak coincident with system peak are provided in the following table, and are measured at delivery point level.

Monthly Coincident Regional Peak at Delivery Point Level
(MW)

Year/Regic	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2010												
Central	10,914	10,802	10,222	9,232	9,554	11,466	12,204	11,436	10,921	9,250	9,781	10,880
East	3,242	3,224	2,825	2,396	2,578	2,899	3,182	3,020	2,913	2,515	2,889	3,183
Northeast	1,221	1,180	1,142	993	760	845	846	898	826	1,128	1,176	1,236
Northwest	497	485	534	411	314	357	353	362	302	491	479	536
Southwest	4,701	4,623	4,439	4,067	4,040	5,107	5,402	5,157	4,825	4,061	4,384	4,696
2011												
Central	10,797	10,847	10,171	9,151	9,466	11,297	12,155	11,554	10,703	9,279	10,139	10,853
East	3,403	3,242	3,033	2,557	2,358	2,734	3,045	2,598	2,630	2,532	2,834	3,097
Northeast	1,226	1,212	1,178	913	591	615	732	926	919	960	1,041	1,129
Northwest	484	534	533	449	316	347	335	423	389	499	481	493
Southwest	4,651	4,612	4,431	3,835	4,278	4,983	5,284	4,933	4,964	4,059	4,424	4,810
2012												
Central	10,514	10,984	10,198	9,219	9,784	11,106	12,268	11,098	10,470	9,466	9,850	10,661
East	3,209	3,256	3,135	2,443	2,157	2,756	2,845	2,944	2,618	2,323	2,674	3,237
Northeast	1,152	1,151	1,082	923	731	759	741	879	974	879	1,003	1,107
Northwest	542	499	577	505	355	372	358	425	517	385	512	495
Southwest	4,638	4,668	4,348	3,877	3,670	4,839	5,415	4,833	4,731	4,396	4,424	4,616
2013												
Central	10,531	11,028	10,231	9,280	9,869	10,988	12,131	10,993	10,427	9,487	9,866	10,668
East	3,214	3,269	3,145	2,459	2,176	2,727	2,813	2,917	2,607	2,328	2,678	3,239
Northeast	1,154	1,156	1,085	929	737	751	733	871	970	881	1,005	1,108
Northwest	543	501	579	509	358	368	354	421	515	386	513	495
Southwest	4,645	4,687	4,362	3,903	3,702	4,788	5,355	4,787	4,712	4,406	4,431	4,620
2014												
Central	10,462	10,971	10,187	9,099	8,881	10,749	11,872	10,743	10,286	9,404	9,639	10,749
East	3,173	3,232	3,112	2,340	2,167	2,649	2,733	2,773	2,555	2,295	2,602	3,101
Northeast	1,104	1,109	1,043	840	596	701	693	850	915	839	924	1,052
Northwest	521	483	557	458	341	347	337	402	486	371	479	479
Southwest	4,580	4,633	4,317	3,709	3,809	4,649	5,209	4,709	4,610	4,344	4,275	4,450

Vulnerable Energy Consumers Coalition (VECC)INTERROGATORY #25 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, Appendices D and E

a) Appendix E sets out 3 approaches to including CDM in a load forecast. Please describe how these three methods relate to the use of explicit and implicit modeling approaches as surveyed by Hydro One and reported on in Appendix D.·

b) What has Hydro One concluded from its survey regarding the use, by other utilities, of the three difference approaches described in Appendix E.

Response

a) Method 1 and Method 2 as described in Appendix E are two different forms of implicit modeling approach, while Method 3 is an explicit approach.

b) The results of the survey regarding the use of the three modeling approaches used by other utilities can be found in Exhibit A, Tab 15, Schedule 2, Attachment 1, Appendix D. It is evident from the survey results that each utility/entity uses one of the three methodologies described in Appendix E to incorporate CDM impacts into the load forecast that is most suitable to its unique situation (i.e. data availability, regulatory requirements, method used to recover lost revenue due to CDM etc.).

<u>Association of Major Power Consumers in Ontario (AMPCO) INTERROGATORY #1 List 1</u>

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

Interrogatory

Ref: Hydro One Application EB-2010-0002 Ex A/Tab 12/Sch 3/P19/Table 3
Ref: Hydro one Application EB-2012-0031 Ex A/Tab 15/Sch2/p21/Table 3

a) The forecast of net demand after embedded generation and CDM in 2012 appears to be different in these two documents. Please explain.

Response

The forecast of net demand after embedded generation and CDM in 2012 in EB-2012-0032 (20,339 MW) is 47 MW higher than the 2012 forecast in EB-2010-0002. The difference for these 2 forecasts can be explained by the following factors:

- Weaker economic forecast used in EB-2012-0031;
- Lower actual load for 2011 used in EB-2012-0031;
- Lower CDM impacts provided by the OPA used in EB-2012-0031;
- Higher embedded generation used in EB-2012-0031; and
- Higher adjustment for peak and energy used in EB-2012-0031.

Association of Major Power Consumers in Ontario (AMPCO) INTERROGATORY #2 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

Ref: Ex A/Tab15/Sch 2/p23/Table 5

a) Please reproduce this table for the years 1999-2011 with added columns for the forecast average monthly transmission peak demand, actual average monthly peak transmission demand that occurred (non-weather corrected) and percentage variation between the two.

Response

The requested information is provided in the following table.

Comparison of Average Monthly Transmission Peak Demand Forecast with Actual
(Variance of forecast as percentage of actual)

	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	Actual	Variance for Plan Year	Variance for Second Year	Variance for Third Year
1999	20,776													21,060	-1.35	-3.11	-2.76
2000	20,896	21,407												21,566	-0.74	-0.21	-3.87
2001	21,060	21,612	21,526											21,658	-0.61	-4.36	-1.27
2002		21,857	21,747	21,842										22,737	-3.94	-1.32	-1.08
2003			22,035	22,023	21,999									22,317	-1.42	-0.85	-2.79
2004				22,133	22,185	22,183								22,375	-0.86	-3.02	-2.55
2005					22,431	22,377	22,285							23,074	-3.42	-3.06	-5.67
2006						22,073	21,958	21,727						22,650	-4.08	-6.20	-0.98
2007							21,684	21,563	21,677					22,988	-5.71	-0.95	3.32
2008								21,606	21,613	21,492				21,820	-1.50	2.85	-3.88
2009									21,489	21,391	21,290			20,798	2.37	-4.96	-3.74
2010										20,734	20,503	20,891		21,572	-3.15	-2.62	n.a.
2011											20,376	20,613	20,465	21,168	-3.32	n.a.	n.a.
Mean															-2.13	-2.32	-2.30
One standard deviation (+/-)															2.54	3.35	3.58

Association of Major Power Consumers in Ontario (AMPCO) INTERROGATORY #3
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

Ref: Ex A/Tab15/Sch2/P24/Table 3

a) Please reproduce this table without weather correction (i.e., actual differences from forecast)

Response

The updated Table 3 without weather correction for 2011 is provided below.

Historical Board Approved Forecasts
vs. Historical Actual

Connection Type	Difference from Actual (%) *			
	EB-2006-0501 Forecast	EB-2008-0272 Forecast	EB-2010-0002 Forecast	**Average**
Network	-4.53	-1.30	-3.55	**-3.12**
Line	-4.75	0.37	-2.47	**-2.28**
Transformation	-5.25	-0.73	-2.80	**-2.93**
Average	**-4.84**	**-0.55**	**-2.94**	**-2.78**
One Standard Deviation (+/-) **	4.87	4.87	4.59	

* A negative (positive) variance shows that actual was above (below) forecast.
** Reflects expected deviation of forecast from actual based on historical variations. For EB-2006-0501 and EB-2008-0272, 2-year standard deviation is used, and for EB-2010-0002, 1-year standard deviation is used.

London Property Management Association (LPMA) INTERROGATORY #6 List 1

Issue 4 Are Other Revenue (including export revenue) forecasts appropriate?

Interrogatory

Ref: Exhibit C1, Tab 4, Schedule 6, Table 1 and Exhibit E1, Tab 2, Schedule 1, Table 1

a) Please provide a table for each of the Station Maintenance and Engineering & Construction categories for 2009 through 2014 that shows the revenues, costs and net margin associated with each of the two categories.

b) Please explain any trends or significant changes from year to year in the net margins shown in part (a) above.

Response

a)

	2009 Historic			2010 Historic			2011 Historic		
	Revenues	Cost	Margin	Revenues	Cost	Margin	Revenues	Cost	Margin
Station Maintenance	14.6	9.7	33.6%	14.7	11.4	22.4%	11.3	8.7	23.0%
Engineering & Project Delivery	3.2	2.9	9.4%	6.5	2.7	58.5%	3.6	3.8	-5.6%
Totals	17.8	12.6	29.2%	21.2	14.1	33.5%	14.9	12.5	16.1%

	2012 Bridge			2013 Test			2014 Test		
	Revenues	Cost	Margin	Revenues	Cost	Margin	Revenues	Cost	Margin
Station Maintenance	10.2	9.1	10.8%	8.1	7.3	9.9%	8.1	7.2	11.1%
Engineering & Project Delivery	11.8	11.2	5.1%	3.0	2.9	3.3%	3.0	2.9	3.3%
Totals	22.0	20.3	7.7%	11.1	10.2	8.1%	11.1	10.1	9.0%

b) The most significant variance in Net Margin percentage is the 2010 E&PD Margin and 2011 E&PD Margin compared to other years in the table. The 2010 Margin was higher than normal due to revenues primarily associated with the temporary bypass of Hydro One facilities, with no related cost. The 2011 Margin was lower than expected mainly due to a one time reversal of revenue for a correction in respect of a prior period.

London Property Management Association (LPMA) INTERROGATORY #7 List 1

Issue 4 Are Other Revenue (including export revenue) forecasts appropriate?

Interrogatory

Ref: Exhibit E1, Tab 2, Schedule 1, Table 1 and Exhibit C1, Tab 4, Schedule 6, Table 1

a) Please provide a table similar to Table 1 of Exhibit E1, Tab 2, Schedule 1, showing 2011 actual as compared to the EB-2010-0002 forecast for 2011.

b) Please provide a table similar to Table 1 of Exhibit E1, Tab 2, Schedule 1, showing 2012 forecast as compared to the EB-2010-0002 forecast for 2012.

c) Please provide a table similar to Table 1 of Exhibit C1, Tab 4, Schedule 6 showing 2011 actual as compared to the EB-2010-0002 forecast for 2011.

d) Please provide a table similar to Table 1 of Exhibit C1, Tab 4, Schedule 6 showing 2012 forecast as compared to the EB-2010-0002 forecast for 2012.

Response

a)

External Revenue		
	2011 Actual	2011 Forecast from 2010
Secondary Land Use	20.6	12.6
Station Maintenance	11.3	4.6
Engineering & Project Delivery	3.6	11.0
Other External Revenues	6.1	3.2
Totals	41.6	31.3

b)

External Revenue		
	2012 Forecast	2012 Forecast from 2010
Secondary Land Use	13.3	12.5
Station Maintenance	10.2	3.0
Engineering & Project Delivery	11.8	6.0
Other External Revenues	3.3	3.2
Totals	38.6	24.7

c)

External Cost		
	2011 Actual	2011 Forecast from 2010
Station Maintenance	8.7	4.0
Engineering & Project Delivery	3.8	10.4
Other External Revenues	0.3	0.5
Totals	12.8	14.9

d)

External Cost		
	2012 Forecast	2012 Forecast from 2010
Station Maintenance	9.1	2.6
Engineering & Project Delivery	11.2	5.4
Other External Revenues	0.7	0.5
Totals	21.0	8.5

London Property Management Association (LPMA) INTERROGATORY #8 List 1

Issue 4 Are Other Revenue (including export revenue) forecasts appropriate?

Interrogatory

Ref: Exhibit E1, Tab 2, Schedule 1, Table 2

In EB-2010-0002 Hydro One forecast Other External revenues of $3.2 million for 2011. Actual 2011 was $6.9 million, or 170% above forecast.

a) Please explain this significant variance from forecast.

b) What is the current projection, based on the most recent year-to-date actual data for other external revenues in 2012?

c) Does Hydro One believe that customers should receive the full benefit of these other external revenues and that Hydro One should not be at risk for its forecast? If not, why not.

d) Does Hydro One agree that a variance account should be used for Other External Revenues, in the same manner as the Board decided was appropriate in EB-2010-0002 for secondary land use and station maintenance & E&CS services? If not, why not?

Response

a) The variance from forecast is mainly due to higher revenues associated with load true-ups on customer-initiated transmission modification projects which are reviewed according to the anniversary dates of their respective contracts per the Transmission System Code, and higher revenues than expected for Health Safety & Environment and Internal Revenue work for Remotes and Telecom.

b) Approximately $4M.

c) Yes.

d) Yes, a variance account could be considered for Other External Revenues.

London Property Management Association (LPMA) INTERROGATORY #9 List 1

Issue 4 Are Other Revenue (including export revenue) forecasts appropriate?

Interrogatory

Ref: Exhibit E1, Tab 1, Schedule 1

a) Please provide the actual export revenue credit for 2010, 2011 and the current forecast for 2012.
b) What is driving the decrease in the export revenue credit forecast from $31.0 million in 2013 to $30.1 million in 2013?

c) Is Hydro One proposing the continuation of the Export Service Credit Revenue variance account in 2013 and 2014? If not, why not?

Response

a) The information requested is included in the response to part a) of Exhibit I, Tab 4, Schedule 2.05 LPMA 10.

b) The 2013 and 2014 forecast export revenue credits are based on the average volume of exports in the 3 prior years, as shown in the response to part a) of Exhibit I, Tab 4, Schedule 2.05 LPMA 10. The forecast export revenue decreases in 2014 because the high export volumes experienced in 2009 and 2010 are dropped from the 3-year average calculation.

c) Yes, Hydro One is proposing the continuation of the Excess Export Service Revenue Account, but is not proposing to continue the continuation of the Deferred Export Service Credit Revenue Account as indicated in Exhibit F, Tab 1, Schedule 2.

London Property Management Association (LPMA) INTERROGATORY #10 List 1

Issue 4 Are Other Revenue (including export revenue) forecasts appropriate?

Interrogatory

Ref: Exhibit H1, Tab 5, Schedule 1, page 3

a) Please provide the historical data, by year, that has been used to calculate the 3 year average volume of electricity exported from or wheeled through Ontario over the transmission system.

b) Please provide the most recent year-to-date volume for 2012, along with the figure for the corresponding period in 2011.

Response

a)

	2009 Actual	2010 Actual	2011 Actual	2012 ('09-'11 Avg)	2013 ('10-'12 Avg)	2014 ('11-'13 Avg)
Export Revenue ($)	$16,816,964	$16,826,031	$27,615,668	$31,633,886	$30,967,205	$30,072,253
ETS Tariff ($/MWh)	1	1	2	2	2	2
Export MWh	16,816,964	16,826,031	13,807,834	15,816,943	15,483,603	15,036,127

b)

	2011 June YTD	2012 June YTD
Export Revenue ($)	$15,046,388	$14,965,379
ETS Tariff ($/MWh)	2	2
Export MWh	7,523,194	7,482,690

London Property Management Association (LPMA) INTERROGATORY #11 List 1

Issue 4 Are Other Revenue (including export revenue) forecasts appropriate?

Interrogatory

Ref: Exhibit E1, Tab 2, Schedule 1

a) For each line item shown in Table 1, please indicate whether or not there is currently a variance account around the amounts forecast and included in rates in 2011 and 2012.

b) For each variance account noted in part (a), please indicate whether Hydro One proposes to close the account, keep the account as is, or make changes to the account.

Response

Please see table below:

	(a) Does a variance account currently exist for the amounts forecasts?	(b) Is Hydro One proposing to maintain the account in the test years in its present form?
Secondary Land Use	Yes	Yes
Station Maintenance	Yes	Yes
Engineering & Project Delivery	Yes	Yes
Other External Revenues	No	Not Applicable

Vulnerable Energy Consumers Coalition (VECC)INTERROGATORY #26 List 1

Issue 4 Are Other Revenue (including export revenue) forecasts appropriate?

Interrogatory

Reference: Exhibit E1, Tab 2, Schedule 1, pages 2- 3

a) Please provide a schedule that sets out the year-to-date 2012 External Revenues for each of the four categories in Table 1 and that also sets out the year to-date values for the same period in 2010 and 2011.

b) How much did Hydro One receive in 2011 for the granting of easement rights to the Region of York and the City of Toronto?

Response

a)

Table 1
External Revenues ($ Millions)

$M	**2010 YTD June Actual**	**2011 YTD June Actual**	**2012 YTD June Actual**
Secondary Land Use	8.4	11.7	12.7
Station Maintenance	7.9	6.2	6.2
Engineering & Project Delivery	1.3	1.6	0.6
Other External Revenues	1.7	1.7	2.5
Totals	**19.3**	**21.2**	**22.0**

b) In 2011, Hydro One received $3.5 million for the granting of easement rights to the Municipality of York and the City of Toronto.

Vulnerable Energy Consumers Coalition (VECC)INTERROGATORY #27 List 1

Issue 4 Are Other Revenue (including export revenue) forecasts appropriate?

Interrogatory

Reference: Exhibit E1, Tab 2, Schedule 1, page 4

a) Please provide a schedule that compares the forecast revenues from Station Maintenance as included Hydro One's EB-2010-002 and EB-2008- 0272 applications with the actual revenues received for the years 2009- 2011.

Response

a)

Station Maintenance	Forecast from 2008 Filing			Forecast from 2010 Filing			Actuals		
	2009	2010	2011	2009	2010	2011	2009	2010	2011
	3.4	2.9	n/a	14.6	2.9	4.6	14.6	14.7	11.3

The differences in forecast and actuals are captured in the External Station Maintenance and E&CS Revenue account as described in Exhibit F1, Tab 1, Schedule 1, page 5.

Vulnerable Energy Consumers Coalition (VECC)INTERROGATORY #28 List 1

Issue 4 Are Other Revenue (including export revenue) forecasts appropriate?

Interrogatory

Reference: Exhibit E1, Tab 2, Schedule 1, page 6

a) Please explain more fully the "lease of idle transmission lines" referenced on line 8.

Response

Please see the response to Exhibit I, Tab 4, Schedule 10.02 CCC 7.

Vulnerable Energy Consumers Coalition (VECC)INTERROGATORY #29 List 1

Issue 4 Are Other Revenue (including export revenue) forecasts appropriate?

Interrogatory

Reference: Exhibit H1, Tab 5, Schedule 1, page 3

a) Please provide a schedule that sets out the actual annual export volumes and revenues for the year 2007-2011. If the volumes and revenue don't reconcile with the approved $1/MWh export tariff during this period, please explain why.

b) Please provide a schedule that sets out the year-to-date export volumes for 2012 and contrast with the 2011 volumes over the same period.

c) What are the assumed export volumes underlying the $31.0 M and $30.1 M in ETS revenues forecast for 2013 and 2014 respectively?

Response

a) The information requested is provided below and reconciles with the approved ETS of $1/MWh applicable from 2007-2010 and $2/MWh applicable in 2011.

	2007 Actual	2008 Actual	2009 Actual	2010 Actual	2011 Actual
Export Revenue ($)	$14,131,472	$24,289,555	$16,816,964	$16,826,031	$27,615,668
ETS Tariff ($/MWh)	1	1	1	1	2
Export MWh	14,131,472	24,289,555	16,816,964	16,826,031	13,807,834

b) See the response to Exhibit I, Tab 4, Schedule 2.05 LPMA 10, part b)

c) See the response to Exhibit I, Tab 4, Schedule 2.05 LPMA 10, part b)

School Energy Coalition (SEC) INTERROGATORY #7 List 1

Issue 4 Are Other Revenue (including export revenue) forecasts appropriate?

Interrogatory

With respect to bypass compensation obligations under the Transmission System Code (TSC):

a. Please provide a list of all instances since 2006 where a customer has bypassed the Applicant's systems as defined under the TSC.
b. For each instance, please provide the amount of bypass compensation paid and any deviations from the terms of the Board approved Connection Cost Recovery Agreements entered into.
c. For each instance, please confirm that the asset bypassed (now stranded) has been removed from rate base.

Response

a. Hydro One has had two such instances. They are:
Stanley TS
Detweiler TS

b. The amount of the bypass compensation for each instance is:
$336k (Stanley TS)
$6M (Detweiler TS)

A customer's liability to pay bypass compensation and the methodology by which the bypass compensation amount is calculated are not set out in the customer's Connection Cost Recovery Agreement. All instances of bypass compensation listed above are consistent with the methodology pertaining to bypass situations as set out in the Transmission System Code.

c. Hydro One confirms that rate base has been adjusted for each instance through an adjustment to the Net Book Value of the bypassed facility.

Consumers Council of Canada (CCC) INTERROGATORY #6 List 1

Issue 4 Are Other Revenue (including export revenue) forecasts appropriate?

Interrogatory

(Ex El/T2/S1) Please recast Table I- External Revenues to include Board approved amounts for 2009-2012.

Response

$M	2009		2010		2011		2012	
	Historic	Board Approved	Historic	Board Approved	Historic	Board Approved	Bridge	Board Approved
Secondary Land Use	14.2	11.4	17.4	11.3	20.6	12.6	13.3	12.5
Stations Maintenance	14.6	3.4	14.7	2.9	11.3	4.6	10.2	3
Engineering & Construction	3.2	1.5	6.5	1.5	3.6	11	11.8	6
Other External Revenues	3.2	2.3	3.8	2.3	6.1	3.2	3.3	3.2
Totals	35.2	18.6	42.4	18.0	41.6	31.3	38.6	24.7

Consumers Council of Canada (CCC) INTERROGATORY #7 List 1

Issue 4 Are Other Revenue (including export revenue) forecasts appropriate?

Interrogatory

(Ex. E1/T2/S 1/p. 5) Please provide a detailed budget for Other Miscellaneous Revenues. Please explain what HONI's policy is with respect to the leasing of idle transmission lines. How are the lease rates derived?

Response

Table 2
Other External Revenues
Other Miscellaneous Revenues

	2012 Bridge $ M
Internal	
Fibre Lease and Indefeasible Rights of Use (IRU) Arrangements	0.6
Lease of Microwave Towers and Contribution to Maintenance	0.3
Engineering work	0.6
Other Miscellaneous Revenue (System Costs to Subs)	0.4
Total Internal Revenue	**1.9**
External	
Connection Upgrades, Lines Maintenance	0.2
Use of Idle Lines by LDC's	0.1
Telecommunications from IESO and OPG	0.4
External Contracting - Tx Customer Impact Assessments for Connected Generation Studies	0.3
Total External Revenue	**1.0**
Total Other Miscellaneous Revenue	**2.9**

Hydro One will consider requests from OEB licensed Distributors to use its idle transmission lines for distribution purposes. The fully-allocated costs of the Asset Condition Assessment, the investments needed to enable the use of the transmission line for distribution purposes, the Technical Review and the connection/disconnection shall be recovered from the Utility. The costs of Hydro One owning and maintaining an idle transmission line while it is used as a distribution line shall be recovered from the Utility and will not be subsidized by Transmission rate payers.

Ontario Energy Board (Board Staff) INTERROGATORY #23 List 1

Issue 5 **Are the proposed spending levels for Sustaining, Development and Operations OM&A in 2013 and 2014 appropriate, including consideration of factors such as system reliability and asset condition?**

Interrogatory

Ref: Exhibit C1/Tab3/Sch2/p 3
Hydro One indicates that the 2012 Sustaining work program was adjusted to stay within the overall Transmission business OM&A envelope approved in the EB-2012-0002 decision. In light of the evidence in this proceeding that indicates a deterioration of the system and an urgency to replace and repair assets, what was the rationale for the cut to the sustaining budget in 2012 by over $25 million or 10.5%?

Response

The need for Hydro One to maintain OM&A and increase capital spending in the Sustaining work program due to asset age and condition is well supported in the evidence in this case and the last transmission proceeding.

Nevertheless, in order to maintain 2012 OM&A at the Board approved level, reductions in spending have been made in all work program areas, Sustaining, Development, Operations and Shared Services. This is shown in the evidence in Exhibit C1, Tab 3, Schedule 1, Table 3 on page 6 and in the interrogatory response in Exhibit I, Tab 6, Schedule 5.02 VECC 31, part b). Further details regarding the areas of Sustaining, Development and Operations that were reduced are listed in Exhibit I, Tab 6, Schedule 5.02 VECC 31, part c).

The decisions on where short term reductions can be made in 2012 were based on a review of all programs following the process outlined in Exhibit A, Tab 15, Schedules 3 and 4.

Ontario Energy Board (Board Staff) INTERROGATORY #24 List 1

Issue 5 **Are the proposed spending levels for Sustaining, Development and Operations OM&A in 2013 and 2014 appropriate, including consideration of factors such as system reliability and asset condition?**

Interrogatory

Ref: Exhibit C1/Tab3/Sch2/p 39
Site security costs increase significantly from the historical years in both test years (to $30.8 Million in 2014) and this is mainly attributed to copper theft. What evidence is there that copper theft will increase in the test years over existing levels?

Response

For clarification, the $30.8 million in 2014 includes all Site Infrastructure Maintenance OM&A expenditures. Further breakdown is provided in Table 10 of Exhibit C1, Tab 3, Schedule 2 on page 37.

Exhibit C1, Tab 3, Schedule 2 pages 38-39 provide information on site security program requirements, which are $2.8 million and $2.7 million for the 2013 and 2014 test years respectively.

Ontario Energy Board (Board Staff) INTERROGATORY #25 List 1

Issue 5 **Are the proposed spending levels for Sustaining, Development and Operations OM&A in 2013 and 2014 appropriate, including consideration of factors such as system reliability and asset condition?**

Interrogatory

Ref: Exhibit C1/Tab3/Sch4/p 3
Hydro One indicates that the Operations Support spending shows an increase in the bridge year and similar increases in the test years is due to standard cost escalation. What does Hydro One mean by the term 'standard cost escalation'?

Response

"Standard cost escalation" was used to express the year-to-year increases in software licenses, vendor maintenance contracts, and consumables to support the operating facilities at the Ontario Grid Control Centre, Back-up Control Centre and remote operating data collection sites. It also includes negotiated labour increases.

Ontario Energy Board (Board Staff) INTERROGATORY #26

Issue 5 **Are the proposed spending levels for Sustaining, Development and Operations OM&A in 2013 and 2014 appropriate, including consideration of factors such as system reliability and asset condition?**

Interrogatory

Ref: Exhibit C1/Tab 1/Sch 1
Please provide a table that identifies the O&M cost per km of transmission Line and O&M per total fixed transmission assets from 2006 to the 2014 test year inclusive.

Response

The following Table 1 summarizes the Transmission (Tx) values for:

- O&M / Circuit km
- O&M / Gross Fixed Assets (GFA)

Table 1: Transmission O&M, Gross Fixed Assets (GFA), and Line Circuit Kilometers

		Historic						Bridge	Test	
	Unit	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**
O&M	$M	236.8	269.8	259.6	284.1	279.5	303.3	288.8	312.4	319.7
Tx Circuit	km	28,430	28,468	28,511	28,533	28,565	28,561	28,608	28,635	28,663
GFA	$M	9,793	10,103	10,481	11,081	11,928	12,687	13,936	14,800	15,787
O&M / km	$/km	8,330	9,476	9,105	9,957	9,784	10,618	10,095	10,908	11,155
O&M / GFA	%	2.42%	2.67%	2.48%	2.56%	2.34%	2.39%	2.07%	2.11%	2.03%

Ontario Energy Board (Board Staff) INTERROGATORY #27 List 1

Issue 5 **Are the proposed spending levels for Sustaining, Development and Operations OM&A in 2013 and 2014 appropriate, including consideration of factors such as system reliability and asset condition?**

Interrogatory

Ref: Exhibit C1/Tab2/Sch2/p 3
Hydro One mentions that there is 'redundancy' found in the transmission system and that an equipment failure to have only a momentary impact on the power system. Has Hydro One defined its level of redundancy in any consistent way and is its redundancy level higher or lower than other North American transmitters?

Response

In its design of the transmission system, Hydro One must follow applicable industry standards. The North American Electric Reliability Corporation's (NERC) Planning Standards are applicable to all facilities operated at 100 kV and higher and are a requirement for transmission utilities throughout all of North America. These standards dictate performance requirements following certain events (i.e. various types of unforeseen faults on the system) known to have impact on the power system. Compliance with these performance requirements often requires redundancy within the design of the system. Therefore, Hydro One's level of redundancy within its transmission system is consistent with those of other transmitters in North America which also design to the same standards.

Ontario Energy Board (Board Staff) INTERROGATORY #28 List 1

Issue 5 **Are the proposed spending levels for Sustaining, Development and Operations OM&A in 2013 and 2014 appropriate, including consideration of factors such as system reliability and asset condition?**

Interrogatory

Ref: Exhibit C1/Tab2/Sch2/p 7
Hydro One mentions that sustaining work programs are focused on replacing or refurbishing lines equipment with the greatest impact on system reliability. How does Hydro One determine this and how does this focus impact sustaining work program priorities?

Response

The impact to system reliability for lines expenditures is determined based on a number of factors including voltage level, whether the supply is single or multi circuit supply, and the type of load.

The impact to system reliability is one of several factors used in the planning and prioritization of Sustaining investments, as outlined in Exhibit C1, Tab 2, Schedule 2.

Ontario Energy Board (Board Staff) INTERROGATORY #29 List 1

Issue 5 **Are the proposed spending levels for Sustaining, Development and Operations OM&A in 2013 and 2014 appropriate, including consideration of factors such as system reliability and asset condition?**

Interrogatory

Ref: Exhibit C1/Tab2/Sch2/pp 9 & 19
In the Circuit Breakers at a Glance table (p.9), capital investment in 2009-11 is $48 million accounting for 71 replacements, or $0.68 million per replacement. For 2012-14, capital investment is $106 million accounting for 95 replacements, or $1.1 million per replacement. This is an increase of 62% per replacement. Please provide the rationale for this increase.

In the Transformers at a Glance table (p.19), capital investment in 2009-11 is $82 million accounting for 10 replacements, or $8.2 million per replacement. For 2012-14, capital investment is $123 million accounting for 19 replacements, or $6.5 million per replacement. This is a per unit decrease of over 20%. Why are Transformer capital costs falling per unit when the Circuit Breaker costs as cited above are increasing?

Response

The cost of replacement of breakers and transformers vary with the specifications of the equipment as well as site-specific details.

In the case of circuit breakers the costs can range from $100 thousand for a medium voltage metal-clad breaker up to $3 million for the replacement of a 500kV air blast breaker. In the 2012-14 time period there are plans to replace a much greater quantity of high voltage air blast breakers which accounts for a large portion of the increase in general circuit breaker unit cost between the two time periods.

In the case of transformers, replacement costs can range from $4 million for a 115kV/25MVA transformer to $25 million for a 500kV / 750 MVA autotransformer. The period from 2009-11 saw the replacement of a greater number of higher MVA transformers which carry a higher unit cost than the transformers planned for replacement over the 2012-14 period.

Ontario Energy Board (Board Staff) INTERROGATORY #30 List 1

Issue 5 **Are the proposed spending levels for Sustaining, Development and Operations OM&A in 2013 and 2014 appropriate, including consideration of factors such as system reliability and asset condition?**

Interrogatory

Ref: Exhibit C1/Tab2/Sch2/p 16
The table on this page shows that the number of Sustaining Circuit Breaker replacements falls from 100 in 2011 to 57 in 2012, and then increases to 104 in 2013 and 124 in 2014. What are the reasons for the fall in replacements in 2012, considering the tone of the evidence that replacements are urgently needed?

Response

Although the number of replacements is lower in 2012 versus 2011, the 2012 expenditures of $77 million are substantially higher than the 2011 expenditures of $56 million summarized in Exhibit C1, Tab 2, Schedule 2, page 16. The 2012 work program includes an increased volume of work on higher-cost circuit breaker replacements as compared with 2011, primarily the air-blast breakers going in-service in 2012 and beyond.

Ontario Energy Board (Board Staff) INTERROGATORY #31 List 1

Issue 5 **Are the proposed spending levels for Sustaining, Development and Operations OM&A in 2013-2014 appropriate, including consideration of factors such as system reliability and asset condition?**

Interrogatory

Ref: Exhibit C1/Tab2/Sch2/p22/Figure7
The table on this page shows that the number of Transformers in very poor condition grows in 2012 to 18 from 4 in 2006 and 5 in 2009. Considering the number of Replacements cited on the same page at lines 15-17, why is there still such growth in the number of very poor transformers?

Response

As indicated on the chart of 2011 Transformer Demographics on page 21, Exhibit C1, Tab 2, Schedule 2, the number of the transformers approaching or beyond their expected service life is accelerating. Currently, 21% of the in-service transformers are beyond their expected service life of 50 years, and an additional 21% of the transformer fleet is approaching expected service life in the near future.

The transformers replaced over the 2007-2011 period have not kept up with the rate of fleet degradation, which is based on industry standard condition assessment criteria. This is the reason why there is still growth in the number of transformers in very poor condition.

The Sustaining capital test year expenditures for transformer replacements outlined in Exhibit D1, Tab 3, Schedule 2 are expected to better manage the continuing pressures associated with the degrading fleet condition and aging installed base.

Ontario Energy Board (Board Staff) INTERROGATORY #32 List 1

Issue 5 **Are the proposed spending levels for Sustaining, Development and Operations OM&A in 2013 and 2014 appropriate, including consideration of factors such as system reliability and asset condition?**

Interrogatory

Ref: Exhibit C1/Tab2/Sch2/p 45
In the Tx Wood Poles at a Glance table, capital investment per pole is constant from 2009-11 to 2012-14, however OM&A grows from $3 million to $5 million, a 67% increase. Why do OM&A costs increase so significantly for wood pole replacements?

Response

Given the demographics of our wood pole population, there is an increase in OM&A due to the required increase in scope of detailed patrols to assess aging hardware. However, the increase is not as large as 67%. The OM&A values in the table are rounded to $3 million and $5 million but the actual values are just under $3.5 million and just over $4.5 million. The increase based on these values is approximately 30%.

Ontario Energy Board (Board Staff) INTERROGATORY #33 List 1

Issue 5 **Are the proposed spending levels for Sustaining, Development and Operations OM&A in 2013 and 2014 appropriate, including consideration of factors such as system reliability and asset condition?**

Interrogatory

Ref: Exhibit C1/Tab2/Sch2/p 53
Hydro One indicates that it plans to begin using composite poles to replace a small portion of its wood pole population to evaluate this emerging technology. Please answer the following: What are composite poles, how do costs compare to current poles, why are they being considered and when will Hydro One be in a position to decide if these poles should be used exclusively in the pole replacement program?

Response

Composite poles are modular structures made of fiber glass and polyurethane resins. Separate modules can be assembled together to build a pole of varying height.

The initial purchase price of composite poles is higher than wood poles, with price difference decreasing significantly with increasing pole height. However, composite poles are anticipated to have a greater life expectancy and lower maintenance costs than wood poles resulting in the lifecycle costs more attractive than wood.

Composite poles are being considered because they are: environmentally friendly, resistant to woodpecker and insect damage, do not rot, fire resistant (self-extinguishing), non-conductive material electrically, light weight hence improved worker safety and they are anticipated to have lower life cycle costs than wood poles.

Hydro One is currently assessing the benefits of composite pole technology to determine if there are any unforeseen issues with this technology. A few years of installation and maintenance experience with composite poles will be required prior to deciding if the technology will be adopted exclusively.

Ontario Energy Board (Board Staff) INTERROGATORY #34 List 1

Issue 5 **Are the proposed spending levels for Sustaining, Development and Operations OM&A in 2013 and 2014 appropriate, including consideration of factors such as system reliability and asset condition?**

Interrogatory

Ref: Exhibit C1/Tab2/Sch2/p 67
In the Tx Conductors at a Glance table, capital investment and Km of line replaced, double from 2009-11 to 2012-14, however the cost per km did not change. In addition, OM&A costs grow by 33%. Why is there no capital cost per replacement saving realized as in the case of transformers and why do OM&A costs grow so significantly?

Response

The lower cost for transformer replacements, as outlined in the response to Exhibit I, Tab 5, Schedule 1.07 Staff 29, is based on the variation in costs for different types of transformers and specific mix of units being replaced. There are not significant cost differences in conductor replacement projects.

The increase in OM&A is required to increase the conductor sample and testing program (see Exhibit C1, Tab 2, Schedule 2 section 4.7, p.66, lines 23-24).

Ontario Energy Board (Board Staff) INTERROGATORY #35 List 1

Issue 5 **Are the proposed spending levels for Sustaining, Development and Operations OM&A in 2013 and 2014 appropriate, including consideration of factors such as system reliability and asset condition?**

Interrogatory

Ref: Exhibit C1/Tab2/Sch2/pp 70 & 72
The two figures on this page depict Forced Outage Frequency and Duration for Conductor. Both figures show a trend of reduced frequency and flat or reduced duration (if 2009 is treated as a non-recurring event). What event caused the 2009 impact? Considering these figures, why is such a significant ramp up required in conductor replacement? (The table on page 72 shows a 240% increase in circuit km and a 318% increase in capital for 2013, continuing in 2014.)

Response

With respect to the 2009 Conductor Forced Outage Duration, Circuit B10, B18H & B20H required an emergency conductor replacement in 2009 which resulted in removing these circuits from the network for an extended period of time.

Many factors are considered for planning replacement needs: demographics and condition as well as the risks associated with failure (which includes reliability). Exhibit C1, Tab 2, Schedule 2, Section 4.7, pages 69-72, provides information on the demographics (16% beyond expected service life today, doubling over the next 10 years at current rate of replacement) and condition of the conductor population as well as the reliability trends.

London Property Management Association (LPMA)*INTERROGATORY #12 List 1*

Issue 5 **Are the proposed spending levels for Sustaining, Development and Operations OM&A in 2013 and 2014 appropriate, including consideration of factors such as system reliability and asset condition?**

Interrogatory

Ref: Exhibit C1, Tab 3, Schedule 1

a) Please provide the most current year-to-date actual expenditures for 2012 in the same level of detail as shown in Table 1. Please also provide the figures for the corresponding period in 2011.

b) What is the driver of the increase $16.8 million in the 2012 bridge year relative to 2011?

Response

a)

Table 1
Summary of Transmission OM&A June Year-To-Date ($ Million)

Description	June YTD	
	2011	**2012**
Sustaining	118.7	105.2
Development	6.6	3.9
Operations	28.8	29.4
Customer Care	0.4	0.5
Shared Services and Other OM&A	27.0	40.5
Property Taxes & Rights Payments	32.9	29.6
TOTAL	**214.4**	**209.1**

b) The increase is primarily due to the increase in Shared Services & Other OM&A. For details on this increase please refer to Exhibit I, Tab 6, Schedule 1.02 Staff 37.

Energy Probe (EP)*INTERROGATORY #11 List 1*

Issue 5 **Are the proposed spending levels for Sustaining, Development and Operations OM&A in 2013 and 2014 appropriate, including consideration of factors such as system reliability and asset condition?**

Interrogatory

Ref: Exhibit C1, Tab 2, Schedule 2, Page 5 - Multi Circuit Delivery Point Interruptions

Figure 2 on Page 5 shows T-SAIFI-mc Contributed by Equipment Failures

a) Please define what the vertical axis “occ./DP/year” stands for.

b) What happened in 2010 to produce the unusually high result?

c) How is the trend line developed?

Response

a) Occurrences per Delivery Point per Year.

b) In 2010, the delivery points supplied by multiple circuits saw a larger number of power interruptions due to equipment failure than in previous years as represented in Figure 2 of Exhibit C1, Tab 2, Schedule 2. The most notable event in 2010 was the failure of the H1L15 230kV oil circuit breaker at Manby TS.

c) The trend line is developed using linear regression over the ten year period of 2002-2011.

Energy Probe (EP)*INTERROGATORY #12 List 1*

Issue 5 **Are the proposed spending levels for Sustaining, Development and Operations OM&A in 2013 and 2014 appropriate, including consideration of factors such as system reliability and asset condition?**

Interrogatory

Ref: Exhibit C1, Tab 2, Schedule 2, Page 6

Figure 3 on Page 6 shows T-SAIFI contributed by lines equipment. It is noted at line 7 that there as been a gradual increase over the past five years in the trend of lines equipment contributing to reliability.

a) Does HONI consider the most recent 5 year trend to be more significant than the 10 year trend? If yes, please explain.

b) Has the data or can the data be subjected to statistical analysis to determine the significance of yearly results or longer term trends? If yes, please provide details of the results of the analysis.

Response

a) The 10 years of performance data presented in the referenced exhibit is a reasonable range of time to provide a trend perspective and an indication of year over year performance variability. In this particular case, since T-SAIFI is a lagging indicator, it's important to be alert to the more recent trends in past 5-years so that the causes behind these trends are understood and can be acted upon in a timely manner, if necessary.

b) Analysis to determine statistical significance has not been performed. The second bullet point on page 6 of Exhibit C1, Tab 2, Schedule 2 is a visual observation from the Figure 3 graph on the same page.

Energy Probe (EP)*INTERROGATORY #13 List 1*

Issue 5 **Are the proposed spending levels for Sustaining, Development and Operations OM&A in 2013 and 2014 appropriate, including consideration of factors such as system reliability and asset condition?**

Interrogatory

Ref: Exhibit C1, Tab 2, Schedule 2, Pages 8-9

Line 32 on Page 8 notes that the test year capital investment for breaker replacement is increasing by 120% of recent historic and bridge years. The chart on Page 9 shows historic average annual replacement numbers of 71 and proposed replacements of 95 which is an increase in numbers replaced of only 33%. Please explain the large increase in unit replacement cost.

Response

An explanation for the increase in unit costs between the two periods of time can be found in Exhibit I, Tab 5, Schedule 1.09 Staff 29.

Energy Probe (EP)*INTERROGATORY #14 List 1*

Issue 5 **Are the proposed spending levels for Sustaining, Development and Operations OM&A in 2013 and 2014 appropriate, including consideration of factors such as system reliability and asset condition?**

Interrogatory

Ref: Exhibit C1, Tab 2, Schedule 2, Pages 11-13

Line 5 on page 11 states that OCBs last longer (55 years) than other breaker types (40 years). Figure 5 on Page 13 shows OCBs having the lowest forced outage rate of all breakers. Replacement of OCBs appears to be with SF6 breakers. Please explain why, given their longevity and reliability, OCBs should not continue to be the dominant breaker used by Hydro One on its system.

Response

The primary factor that limits the continued installation of OCBs is the fact they have not been manufactured for decades, giving way to SF6 and vacuum interrupting technologies.

Several OCB models are technically obsolete, in that parts for routine preventive and corrective maintenance cannot be sourced. Hydro One has agreements in place with aftermarket suppliers for the available components and also salvages components from retired OCBs where feasible.

Hydro One has a large population over 1900 OCBs, and the test year Sustaining capital expenditures covered in ISD #S1 (Exhibit D2, Tab 2, Schedule 3) will result in only 29 being replaced over the 2013 – 2014 period (<0.8% of installed fleet per year). Although a significant portion of the large OCB population is approaching its expected service life, near term expenditures will be focused on the replacement of the worst performing units and/or models which are technically obsolete.

Energy Probe (EP) *INTERROGATORY #15 List 1*

Issue 5 **Are the proposed spending levels for Sustaining, Development and Operations OM&A in 2013 and 2014 appropriate, including consideration of factors such as system reliability and asset condition?**

Interrogatory

Ref: Exhibit C1, Tab 2, Schedule 2, Page 22

Figure 7 on Page 22 shows the condition of the transformer fleet for 2006, 2009 and 2012. Summing the numbers in each year yields 729 in 2006, 718 in 2009 and 719 in 2012. Please explain why the number of transformers declined so much from 2006 levels.

Response

The reason that the 2006 totals decline is that for the 2006 condition assessment, the count of 729 included single phase tanks as separate counts for some transformers which was not the practice is subsequent years. In addition, in 2006 regulators were not included in the assessment count but are included in the condition assessments for transformers in subsequent years. When comparing the total number of power transformers in-service over each of the years under the same set of assumptions, the variation is minimal. Please refer to Exhibit I, Tab 12, Schedule Staff 68 part d.

Energy Probe (EP)*INTERROGATORY #16 List 1*

Issue 5 **Are the proposed spending levels for Sustaining, Development and Operations OM&A in 2013 and 2014 appropriate, including consideration of factors such as system reliability and asset condition?**

Interrogatory

Ref: Exhibit C1, Tab 2, Schedule 2, Page 23

Line 11-12 on Page 23 states that the increased number of transformer failures in 2011 is of concern to Hydro One. Figure 9 on Page 24 shows that the number of failures in 2011 was 6 transformers. Two other years in the chart show 5 transformers failed (2003 and 2006) and three other years had 4 failures (2002, 2007, 2008).

a) How many transformers have failed to date in 2012?

b) Was 2011 an unusual year for loading, weather etc that might have contributed to the number of failures?

c) How much trend significance should be inferred from the 2011 experience particularly in light of the low number of transformers that failed in the previous two years. (2 in each of 2009 and 2010).

Response

a) Year-to-date 2012 (mid-September), there have been four (4) major transformer failures on the Hydro One transmission system. This result, prior to the end of Q3 already exceeds the average of 3.4 major transformer failures per year as presented in Exhibit C1, Tab 2, Schedule 2, page 24 Figure 9.

b) Transformer failure is a complicated process, normally resulting from a combination of various factors such as design, manufacture, condition, loading and environment. Load and demand levels in 2011 do not indicate an unusual year compared to other years, and there was no other unusual condition that may have contributed to the high number of major transformer failures in 2011.

c) The performance failure trend presented, when combined with the deteriorating condition and demographic trends, is a cause for concern. Major transformer failures can result in power interruptions to customers, potential impact to the environment, safety of Hydro One personnel and delays to restore the equipment and power to customers. Also, forced replacements are more costly than planned replacements. It is prudent for Hydro One to keep major transformer failure events to a minimum.

Energy Probe (EP)*INTERROGATORY #17 List 1*

Issue 5 **Are the proposed spending levels for Sustaining, Development and Operations OM&A in 2013 and 2014 appropriate, including consideration of factors such as system reliability and asset condition?**

Interrogatory

Ref: Exhibit C1, Tab 2, Schedule 2, Page 44

This page describes the replacement of wood pole structures and particularly the need to replace 230 kV Gulfport structures.

a) Line 19 states that there were 5800 structures of this type and that 2000 remain. Please confirm that this means there are still 2000 structures needing replacement.

b) Are these structures just receiving new spar arms or are they being completely replaced with a different structure type?

Response

a) Correct, 2000 structures remain and are in need of replacement.

b) These structures are receiving new steel arms in place of the wooden spar arms. The poles are also being replaced depending on their condition.

Energy Probe (EP)*INTERROGATORY #18 List 1*

Issue 5 **Are the proposed spending levels for Sustaining, Development and Operations OM&A in 2013 and 2014 appropriate, including consideration of factors such as system reliability and asset condition?**

Interrogatory

Ref: Exhibit C1, Tab 2, Schedule 2, Appendix A, Page 7

This page concerns the replacement of Air Blast Breakers and mentions two protection schemes specifically: "breaker and a half" and "breaker and a third".

a) Please explain what these schemes consist of.

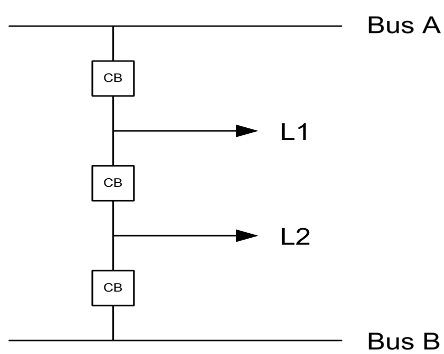
b) Are these schemes deployed just on ABCB systems or on all breakers systems?

Response

a) The "Breaker-and-a-half" and "breaker-and-a-third" are station switchyard configurations that describe the electrical arrangement of various power system elements.

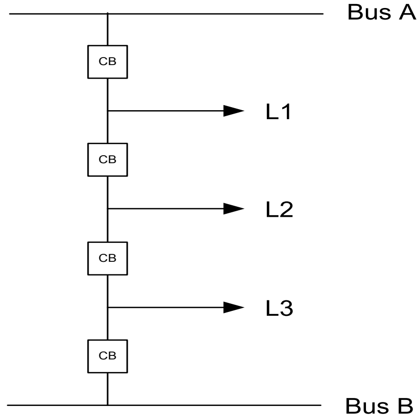
A "Breaker-and-a-half" arrangement consists of three circuit breakers between two buses connecting two transmission facilities, see Figure 1 below.

Figure 1



A "Breaker-and-a-third" arrangement consists of four circuit breakers between two busses connecting three transmission facilities, see Figure 2 below

Figure 2



b) The "breaker and a half" and "breaker and a third" arrangements are not specific to Air Blast Circuit breakers.

Energy Probe (EP)*INTERROGATORY #19 List 1*

Issue 5 **Are the proposed spending levels for Sustaining, Development and Operations OM&A in 2013 and 2014 appropriate, including consideration of factors such as system reliability and asset condition?**

Interrogatory

Ref: Exhibit C1, Tab 2, Schedule 2, Appendix A, Page 13

Page 13 mentions environmental concerns with SF6 gas. Please describe the concerns and how they are managed.

Response

SF6 gas is widely used in circuit breakers, gas-insulated switchgear and related equipment as a dielectric medium due to its excellent dielectric strength as well as its chemical and physical properties. In 1997, the Kyoto Accord identified SF6 gas as a chemical whose emissions should be reduced based on its (i) atmospheric lifetime of 3,200 years and (ii) global warming potential (GWP) of 23,900 (i.e. most potent greenhouse gas known, 23,900 times more potent that carbon dioxide).

Currently, there are no Federal restrictions/prohibitions on SF6 emissions. Total SF6 emissions (leaks and spills) must be reported annually to Environment Canada in accordance with (i) *"CEA/EC Memorandum of Understanding on SF6 Emissions (March 22, 2007)"* and (ii) *"Canadian Environmental Protection Act (CEPA)", Subsection 46(1)*. Provincially, discharges of SF6 into the natural environment are prohibited under the *"Environmental Protection Act" (Sections 6(1) and 14(1)).*

Hydro One takes all reasonable precautions to reduce SF6 gas emissions, promote recyling/re-use and track/manage its inventory. This includes, but not limited to, the following activities:

- Detecting and repairing abnormal leakage from equipment;
- Reducing normal equipment leakage by replacing early vintage SF6-filled equipment with new equipment at the end of its life. New SF6-filled equipment leaks less (0.1-0.5% of volume per year versus 10%+ leakage rate from early vintages). New SF6-filled equipment is also more compact with smaller SF6 gas volumes;
- Continually improving SF6 handling procedures, equipment and training (eg, purchasing gas carts capable of 95-99% gas recovery); and
- Piloting novel technologies such as (i) vacuum interrupter breakers (eliminates SF6 usage), (ii) SF6 gas mixtures (reduces SF6 usage), (iii) real-time leak monitoring equipment (identifies leaks earlier), etc.

Energy Probe (EP)*INTERROGATORY #20 List 1*

Issue 5 **Are the proposed spending levels for Sustaining, Development and Operations OM&A in 2013 and 2014 appropriate, including consideration of factors such as system reliability and asset condition?**

Interrogatory

Ref: Exhibit C1, Tab 6, Schedule 2, Page 5 and Page 12

This exhibit relates to transport and work equipment costs. Page 5 states that the total fleet comprises about 6700 vehicles and pieces of equipment. Page 12 states that 500 units have been equipped with GPS to track a variety of metrics on vehicle operation.

a) What is the average cost to equip a vehicle in the fleet with GPS?

b) What kinds of vehicles have been equipped with GPS so far?

c) What are Hydro One's plans for equipping the rest of the rolling stock part of the fleet?

d) Do supervisors have access to real time GPS data for crew management? If yes, please describe the benefits experienced to date. If no, please explain why this would not be a good crew management tool for supervisors.

Response

a) The average cost to equip a vehicle in the fleet with GPS is about $1,060 per unit. This includes installation and hardware costs.

b) A variety of vehicles have been equipped with GPS so far, including off-road equipment, line maintenance trucks and light transport vehicles.

c) Hydro One is currently performing a cost analysis to evaluate the efficiencies from this system. The planned completion data for this analysis is 2013. Once this analysis is complete Hydro One will decide whether to equip the rest of the rolling stock with GPS.

d) Hydro One is currently conducting pilots in this area with specific supervisors in order to determine the cost effectiveness and benefits of this enhanced option of the GPS system. Based on a review of initial findings from these pilots, results show possible gains in the areas of dispatching and storm response of our lines maintenance trucks and off-road equipment.

Energy Probe (EP)*INTERROGATORY #21 List 1*

Issue 5 **Are the proposed spending levels for Sustaining, Development and Operations OM&A in 2013 and 2014 appropriate, including consideration of factors such as system reliability and asset condition?**

Interrogatory

Ref: Exhibit C1, Tab 6, Schedule 1, Page 14

Lines 1-3 describe equipment utilization factor improvement from 65% in 2001 to 80% in 2011. What criterion is used to determine if a piece of equipment or a vehicle is being utilized?

Response

Utilization is a measurement of available hours versus the hours the equipment is charged out to specific projects/work orders.

Power Workers Union (PWU) INTERROGATORY #2 List 1

Issue 5 **Are the proposed spending levels for Sustaining, Development and Operations OM&A in 2013 and 2014 appropriate, including consideration of factors such as system reliability and asset condition?**

Interrogatory

Ref (1): Exhibit C1/Tab 3/Sch 2/Page 42 of 63/Table 12 (Vegetation Management)

Table 12
Vegetation Management ($ Millions)

Description	**Historic**			**Bridge**	**Test**	
	2009	**2010**	**2011**	**2012**	**2013**	**2014**
Brush control	16.0	15.5	17.0	15.2	17.0	17.2
Line Clearing	3.9	3.2	4.3	4.1	4.7	4.7
Property Owner Contact	1.0	0.6	1.2	1.1	1.2	1.3
Condition Patrols & Annual Inspections	0.9	1.1	1.3	1.9	2.1	2.1
Demand Maintenance	1.3	1.3	1.0	1.3	1.3	1.3
Grounds Maintenance	2.7	2.3	1.9	2.7	2.7	2.7
Total	**25.7**	**24.0**	**26.6**	**26.2**	**29.0**	**29.3**

a) Please provide the corresponding historic and planned levels of accomplishment for the test years for brush control (ha) and line clearing (km).

Response

The corresponding historic accomplishment levels for brush control and line clearing are as follows:

	2009	**2010**	**2011**
Brush Control (ha)	11,259	11,662	11,580
Line Clearing (km)	2,704	2,884	2,878

The planned levels of accomplishment for the test years for brush control and line clearing are as follows:

	2013	**2014**
Brush Control (ha)	11,500	11,500
Line Clearing (km)	2,800	2,800

<u>Power Workers Union (PWU) INTERROGATORY #3 List 1</u>

Issue 5 **Are the proposed spending levels for Sustaining, Development and Operations OM&A in 2013 and 2014 appropriate, including consideration of factors such as system reliability and asset condition?**

<u>Interrogatory</u>

Ref (1): Exhibit A/Tab 15/Sch 3/Page 6 of 21/Lines 3-11

> **<u>Assessing the asset demographics</u>: Assets entering mid or end-of-life are expected to require increased attention to maintain satisfactory level of performance. Maintenance costs of an asset in these periods can increase significantly and the likelihood of needing to refurbish or replace the asset will increase as well. Inspections and testing of such assets are undertaken to assess these needs. The demographic analysis includes a greater planning scope (up to 30 years) to facilitate an understanding of the bow wave of potential future costs. It provides a tangible understanding of the need to ramp up some of our programs to get ahead of and smooth out the future costs of our system to ratepayers.**

Ref (2): EB-2010-0002/Exhibit D1/Tab 2/Sch 1/Pages 9-11 of 74 (Asset End of Life Indication)

Hydro One states (Page 9, Lines 16- 24) the following:

> **Assets are declared EOL in the context of Hydro One's Capital Sustainment programs when the risk of allowing an asset to remain in service in its present condition/situation exceeds acceptable risks associated with Hydro One's business values. EOL is defined as the likelihood of failure, or loss of an asset's ability to provide the intended functionality, wherein the failure or loss of functionality would cause unacceptable consequences. Identifying the appropriate indicators to project an asset's EOL is an important factor in Sustainment planning. Some assets have very specific and agreed to EOL markers, perhaps based on regulations or industry-accepted standards. Others require a number of inputs to identify the risks that prompt an EOL determination.**

Hydro One also lists (page 10-11) factors that it generally considers when assessing an asset's remaining life, including: Condition, Reliability and Performance; Utilization; Technical Obsolescence; Safety & Environment; Cost; Age and Health Indices.

Ref (3): Exhibit C1/Tab 2/Sch 2/Page 21 of 72/Lines 3-5

> **<u>Demographics</u>**
> **Hydro One uses a normal expected service life of 50 years for most transformers. This is based on Hydro One's experience, and is beyond the CEA-average of 40 years.**

a) What is Hydro One's definition of "expected service life"?
b) Is the definition that Hydro One provided in Ref (2) for End of Life (EOL) the definition that Hydro One applies to EOL today? If not, what is Hydro One's definition of EOL?
c) Is "expected service life" the same as EOL?
d) Ref (2) contains descriptions of factors that were generally used when assessing an asset's remaining life. Are these factors the same compliment of factors used today? If there are changes, please describe the changes and the reasons for the changes.
e) As per questions (a) and (b), please confirm that EOL based on age is an appropriate indicator for the suite of considerations that an asset manager considers in making his/her replacement decisions; i.e. asset performance, cost, obsolescence, reliability and safety, etc.
f) Please describe how Hydro One determines the expected service life and/or EOL for its various types of transmission assets.
g) Does Hydro One have targets and/or maximum limits for % EOL (e.g. the percentage of assets beyond the EOL) of its various assets? If no, please explain why not. If yes:
    i) Please provide EOL targets and/or limits for the following transmission asset categories: transformers, breakers, protection and control, underground cables, steel tower structures, conductors and wood pole structures.
    ii) For each of the transmission category listed in (g) (i) above, please explain how the EOL targets and/or limits are derived and the key considerations taken into account in determining the targets/limits.
h) Does Hydro One have asset condition targets based on specific metrics (e.g. the percentage of assets in "poor" or "very poor" condition) for its various assets? If no, please explain why not. If yes,
    i) Please provide asset condition targets and/or limits for the following transmission asset categories: transformers, breakers, protection and control, underground cables, steel tower structures, conductors and wood pole structures.
    ii) For each of the transmission category listed in (h) (i) above, please explain how the asset condition targets are derived.
i) Please outline the considerations that Hydro One has taken into account from its experience to determine that the normal expected life for transformers is 50 years and not 40 years as is used by the CEA.
j) Please confirm if Hydro One currently uses and determines Health Indices as described in Ref (2).
k) Please describe how Hydro One determines when it is economically beneficial to replace or refurbish an asset.

l) Please discuss the influencing factors, other than cost-benefit criterion, that Hydro One takes into account to replace or refurbishment key transmission assets.
m) Does Hydro One use a target for customer and equipment reliability performance based on the performance of Canadian utilities as tracked by the CEA?

Response

a) Hydro One defines "expected service life" as meaning the average time in years that an asset can be expected to operate under normal system conditions.

b) Yes, the same definition still applies.

c) No, expected service life is the typical age at which EOL is expected. Note that multi-dimensional risk assessments drive specific end of life investment decisions.

d) Yes, the same factors still apply (including condition, reliability, utilization, technical obsolescence, safety & environment, cost, age).

e) Expected service life is one of many variables considered when projecting fleet wide replacement scenarios. It is not a single appropriate determinant in making replacement decisions.

f) Expected service life and EOL is determined through a combination of Hydro One's experience and experience of other utilities and manufacturers. Asset investment criteria for Sustaining Capital investment decisions was provided in EB-2010-0002 Exhibit D1, Tab 2, Schedule 1 starting at page 31.

g) Hydro One does not have a hard target for the percentage of individual assets that can be beyond EOL. To do this would ignore the difference in risks between our asset classes and their effect on overall company business values.

h) Hydro One does not have a target metric for the percentage of "very poor" or "poor" assets that is considered to be acceptable. For "very poor" and "poor" assets we generally address the asset within 1 year and 5 years respectively through replacement or refurbishment. Refer to the "10 Year Transmission Asset Management Outlook" in Exhibit A, Tab 13, Schedule 2, page 31for further details.

i) Consideration is given to our operating experience with transformers as well as purchasing specifications, past maintenance practices and other factors.

j) We do currently use health indices to assist with our decision making.

k) Two scenarios are compared over a specified time period and economic comparison is performed using standard NPV methodology.

l) Beyond dollars we also examine the impact an investment will have on reliability, safety, environment, productivity and customers.

m) Hydro One compares its customer and equipment reliability performance to CEA composite reliability levels as an indicator of its performance against peers. CEA composite reliability levels are not used as specific targets. These types of performance comparisons provide Hydro One with relative and directional trend information to compare end results and help shape investment planning.

Power Workers Union (PWU) INTERROGATORY #4 List 1

Issue 5 **Are the proposed spending levels for Sustaining, Development and Operations OM&A in 2013 and 2014 appropriate, including consideration of factors such as system reliability and asset condition?**

Interrogatory

Ref (1): Exhibit C1/Tab2/Sch 2/Page 19 of 72 (Transformers at a Glance)

The Chart in this reference presents historic and proposed levels of investments in transformers as well as the 5-year and 10-year demographic outlook under historic and proposed levels of rates of replacement.

a) Please provide estimates of the annual capital budgets and OM&A costs for transformers for 2016 and 2021 assuming the demographic outlook and the asset condition that Hydro One would expect at that time. Please provide the estimates assuming:
   i) the historic replacement rate of 10 transformers per year (i.e. 2009-2011 average per year); and
   ii) The proposed replacement rate of 19 transformers per year (i.e. 2012-2014 average per year).
b) What are the reliability, safety, environmental and/or operational risk implications for 2016 and 2021 that Hydro One would expect as a result of keeping the transformers sustainment replacements at the historic replacement rate of 10 transformers per year (i.e. 2009-2011 average per year) compared to the proposed replacement rate of 19 transformers per year (i.e. 2012-2014 average per year)?
c) What would be the replacement rate to achieve a target of 0% transformers beyond EOL (i.e. 0% EOL target) in 2021?
d) What would be the annual capital expenditures and OM&A associated with (c) above, i.e., 0% EOL target?
e) Please describe the resourcing constraints that Hydro One is currently facing to meet:
   i) The proposed replacement rate for transformers; and
   ii) The replacement rate for transformers to achieve a 0% EOL target by 2021.
f) If Hydro One is facing resourcing constraints to achieve the proposed replacement rate for transformers, please describe the actions that Hydro One is implementing to tackle those resourcing constraints.

Response

a) The capital and OM&A costs for the Current and Proposed investment levels are presented in the Transformers at a Glance chart in Exhibit C1, Tab 2, Schedule 2, page 19. Although capital and OM&A budgets for years 2016 and 2021 are outside the scope of the current application, the cost levels in the referenced chart can be used as a basis of cost estimate projection.

   i. Continuation of a replacement rate of 10 transformers per year (based on average of per year values 2009-2011) is estimated to cost $82 million per year for capital. The OM&A average for the 2009-11 period of $29 million per year would need to increase through 2021 as the aging fleet would require additional corrective maintenance and refurbishment expenditures to manage reliability and environmental risks.
   ii. The Proposed replacement rate of 19 transformers per year is estimated to cost $123 million per year for capital. Through 2021 it is expected that transformer OM&A expenditures could be generally held constant or gradually decline from the proposed level of $25 million per year.

b) The consequence of keeping the transformers sustainment replacements at the 2009-2011 historic replacement rate of 10 transformers per year compared to the 2012-2014 proposed replacement rate of 19 transformers per year would be an increased and continually increasing proportion of transformers being beyond expected service life. Operating a larger proportion of transformers beyond their expected service life will increase OM&A costs based on an expected increase in refurbishment and corrective maintenance work. This scenario would also increase the risk of unplanned outages and major transformer failures. The result of this scenario would increase the risk of impacts to reliability, safety, and environment in future years (e.g. 2016 and 2021) as described in Exhibit C1, Tab 2, Schedule 2, pages 18 and 20.

c) Based on the demographics of transformers, to eliminate all transformers beyond their expected service life by 2021 would require a significantly increased annual replacement rate of almost double the 2012-14 average over the 2013-2021 period. It should be noted that assessment of assets at their expected service life is not the only factor in determining transformer replacements. There are transformers that are not at their expected service life that require replacement due to other circumstances such as damage experienced due to faults on the system and design deficiencies that become apparent years after their manufacture.

d) It is difficult to estimate the required capital expenditures associated with the scenario in c) due to other dependencies, such as coordination with other capital and OM&A work and the ability to coordinate a higher concentration of planned outages required to carry out such an accelerated work program. For this scenario, significant increases in capital costs beyond the proposed costs would be expected and would be in the range of almost double the 2012-14 average expenditures. The OM&A expenditures would be expected to decline over time, as demand corrective and refurbishment work, typically associated with equipment age and usage, would subside.

e)

i) & ii)

Hydro One has successfully demonstrated the ability to complete the proposed replacement rate over the 2012-14 period. The major factors that impact future work program execution along with actions that Hydro One has taken to increase volume of work are described in the pre-filed evidence on Work Execution Strategy as Exhibit A, Tab 15, Schedule 6. Although Hydro One is not recommending a scenario where 0% of the inventory would be beyond expected service life by 2021, acceleration of the work execution strategy as presented in the reference exhibit would be required to achieve the scenario presented in this question.

f) See above response to part e).

Power Workers Union (PWU) INTERROGATORY #5 List 1

Issue 5 **Are the proposed spending levels for Sustaining, Development and Operations OM&A in 2013 and 2014 appropriate, including consideration of factors such as system reliability and asset condition?**

Interrogatory

Ref (1): Exhibit C1/Tab2/Sch 2/Page 25 of 72/Lines 17-19

Historic and Future Investment

Transformer Portfolio - Historic & Proposed	2007	2008	2009	2010	2011	2012 Forecast	2013 Test Year	2014 Test Year
# of Sustainment replacements*	9	10	4	10	16	11	20	27
% of Fleet	1.2%	1.3%	0.5%	1.4%	2.2%	1.5%	2.7%	3.7%
Capital ($M, Net)	18.7	40.7	48.7	106.8	81.1	72.4	125.6	170.8
OM&A ($M, Net)	28.5	22.6	29.3	26.4	30.2	24.8	23.8	24.9

Note that transformer replacements above are conducted under both the categories of Power Transformers and Station Re-Investment as outlined in Exhibit D1, Tab 3, Schedule 2.

a) Please provide the reasons for the decrease in the projected replacement rate for transformers from 16 in 2011 to 11 in 2012. Was the 2012 decrease not a result of Hydro One's inability to go through with some of the planned work?

Response

Please note that the transformer section of Exhibit C1, Tab 2, Schedule 2 was not updated as part of the August 15th Update to reflect the change in the bridge year expenditures or accomplishment levels.

As outlined in the August 15th, 2012 update of Exhibit D1, Tab 3, Schedule 2, Table 2; the 2012 bridge year forecast capital expenditures for transformers has been increased by approximately $50 million to $111.4 million. This increased the 2012 accomplishment by an additional 10 transformer replacements for a total of 21 replacements in 2012. The increased bridge year expenditures and accomplishments were driven by both demand replacements (i.e. transformer failures), as well as the redirection process as described in Exhibit A, Tab 15, Schedule 4 page 10.

Power Workers Union (PWU) INTERROGATORY #6 List 1

Issue 5 **Are the proposed spending levels for Sustaining, Development and Operations OM&A in 2013 and 2014 appropriate, including consideration of factors such as system reliability and asset condition?**

Interrogatory

Ref (1): Exhibit C1/Tab2/Sch 2/Page 24 of 72/Lines 6-13/Figure 10 (Transformer Forced Outage Frequency and Comparison to CEA):

Hydro One indicates that despite the slight improvement in the trend of transformer forced outages, there is still a significant gap relative to the CEA all-Canada transmission average and that increased replacements are required to maintain the current level of reliability of the transformer fleet given the demographics and changing condition of the fleet.

a) Does Hydro One expect to achieve in the future a Transformer Forced Outage Frequency close to the current CEA transmission average? If not, what would be the replacement rate required to achieve the current CEA benchmark in 2021?

Response

Practically, there are many factors that result in year over year forced outage performance variations as illustrated in Exhibit C1, Tab 2, Schedule 2 page 24, Figure 10. It would be a reasonable goal to be comparable to the CEA forced outage frequency performance average. However, performance serves as only one of several inputs considered in Hydro One's investment plans pertaining to asset replacements. These types of performance comparisons are used mainly to provide relative and directional trend information for Hydro One to compare end results. These considerations are presented in more detail in Exhibit C1, Tab 2, Schedule 2, pages 18 – 25.

Power Workers Union (PWU) INTERROGATORY #7 List 1

Issue 5 **Are the proposed spending levels for Sustaining, Development and Operations OM&A in 2013 and 2014 appropriate, including consideration of factors such as system reliability and asset condition?**

Interrogatory

Ref (1): Exhibit C1/Tab2/Sch 2/Page 9 of 72 (Circuit Breakers at a Glance)

The Chart in this reference presents historic and proposed levels of investments in circuit breakers as well as 5-year and 10-year demographic outlook under historic and proposed levels of rates of replacement.

a) Please provide estimates of annual capital budgets and OM&A costs for circuit breakers for 2016 and 2021 assuming the demographic outlook and asset condition that Hydro One would expect at that time. Please provide the estimates assuming:
   i) The historic replacement rate of 71 circuit breakers per year (i.e. 2009-2011 average per year); and
   ii) The proposed replacement rate of 95 circuit breakers per year (i.e. 2012-2014 average per year).
b) What are the reliability, safety, environmental and/or operational risk implications for 2016 and 2021 that Hydro One would expect as a result of keeping the circuit breaker sustainment replacements at the historic replacement rate of 71 transformers per year (i.e. 2009-2011 average per year) compared to the proposed replacement rate of 95 circuit breakers per year (i.e. 2012-2014 average per year)?
c) What would be the replacement rate to achieve a target of 0% circuit breakers beyond EOL (i.e. 0% EOL target) in 2021?
d) What would be the annual capital expenditures and OM&A associated with (d) above, i.e., 0% EOL target?
e) Please describe the resourcing constraints that Hydro One is currently facing to meet:
   i) The proposed replacement rate for circuit breakers;
   ii) The replacement rate for circuit breakers to achieve a 0% EOL target; and
   iii) The replacement rate for circuit breakers to maintain the current percentage of circuit breakers beyond EOL by 2021. (The resource constraints could include, in principles, insufficient regular labour, hiring hall labour, equipment –breakers in this case, or insufficient up-front planning to carry the increased work, or the inability to get sufficient outages to carry out the work.
f) If Hydro One is facing resourcing constraints to achieve the proposed replacement rate for circuit breakers, please describe the actions that Hydro One is implementing to tackle such resourcing constraints.

Response

a) The capital and OM&A costs for the Current and Proposed investment levels are presented in the Circuit Breakers at a Glance chart in Exhibit C1, Tab 2, Schedule 2, page 9. Although capital and OM&A budgets for years 2016 and 2021 are outside the scope of the current application, the cost levels in the referenced chart can be used as a basis of cost estimate projection.

   i. Continuation of a replacement rate of 71 breakers per year would result in capital costs similar to the 3 year historical average. The OM&A average for the 2009-11 period of $20 million per year would need to increase through 2021 as the aging fleet would require additional corrective maintenance and refurbishment expenditures to manage reliability risks.
   ii. Proposed replacement rate of 95 breakers per year would result in capital costs that are similar to costs shown in the proposed investment in Exhibit C1, Tab 2, Schedule 2, page 9. Through 2021 it is expected that circuit breaker OM&A expenditures could be generally held constant or gradually decline from the proposed level of $17 million per year, especially with the continued replacement of the remaining air-blast breakers.

b) The consequence of keeping the breaker sustainment replacements at the historic replacement rate of 71 breakers per year compared to the proposed replacement rate of 95 breakers per year would be an increased and continually increasing proportion of breakers being beyond expected service life. Operating a larger proportion of breakers beyond their expected service life will increase OM&A costs based on an expected increase in refurbishment and demand corrective work. This scenario would also increase the risk of unplanned outages and major breaker failures. The result of this scenario would increase the risk of impacts to reliability, safety, environmental and operations in future years (e.g. 2016 and 2021) as described in Exhibit C1, Tab 2, Schedule 2, pages 8 and 10.

c) Based on the demographics of breakers, to eliminate all breakers at their expected service life by 2012 would require an annual replacement rate of approximately 12% higher than the proposed annual replacement rate. It should be noted that assessment of assets at their expected service life is not the only challenge, or factor in determining breaker replacements. There are breakers that are not at their expected service life that require repair due to other circumstances such as damage experienced due to faults on the system and design deficiencies that become apparent years after their manufacture.

d) It is difficult to estimate the required capital expenditures associated with the scenario in c) due to other dependencies, such as coordination with other capital and OM&A work and the ability to coordinate a higher concentration of planned outages required to carry out such an accelerated work program. For this scenario, capital costs approximately 12% beyond the proposed costs would be expected. The OM&A expenditures would be expected to decline over time, as demand corrective and refurbishment work, typically associated with equipment age and usage, would subside.

e) (i) (ii) (iii) Hydro One has successfully demonstrated the ability to complete the proposed replacement rate over the 2012-2014 period. The major factors that impact future work program execution along with actions that Hydro One has taken to increase volume of work are described in the pre-filed evidence on Work Execution Strategy as Exhibit A, Tab 15, Schedule 6. Hydro One is not recommending for the test years, a replacement rate where 0% of inventory would be beyond expected service life. This would require an acceleration of the work execution strategy as presented in the reference exhibit.

f) See response under item e).

<u>Power Workers Union (PWU) INTERROGATORY #8 List 1</u>

Issue 5 **Are the proposed spending levels for Sustaining, Development and Operations OM&A in 2013 and 2014 appropriate, including consideration of factors such as system reliability and asset condition?**

<u>Interrogatory</u>

Ref (1): Exhibit C1/Tab2/Sch 2/Page 16 of 72/Lines 17-21

Circuit Breaker Portfolio	Historic					Bridge	Test	
	2007	2008	2009	2010	2011	2012	2013	2014
# of Sustaining replacements*	31	49	33	81	100	57	104	124
% of Fleet	0.7%	1.1%	0.7%	1.8%	2.2%	1.3%	2.3%	2.8%
Capital ($M)	42.6**	75.1**	48.7**	40.4	55.8	77.2	129.3	111.2
OM&A ($M)	19.5	19.8	19.6	16.4	19.3	16.8	18.1	17.3

* Test-year expenditures are a combination of Circuit Breaker capital and System reinvestment expenditures detailed in Sustaining Capital Exhibit D1, Schedule 3, Tab 2.
** Significant expenditures in 2007, 2008, and 2009 for the Claireville 230kV GIS breaker replacements and reconfiguration ($34 million, $50 million, and $20 million respectively).

a) Please indicate if the decrease in the projected replacement rate for circuit breakers from 100 in 2011 to 57 in 2012 was a result of Hydro One's inability to go through with some of the planned work?

<u>Response</u>

a) Please refer to Exhibit I, Tab 5, Schedule 1.08 Staff 30 for explanation of 2012 versus 2011 variance in number of accomplishments.

<u>Power Workers Union (PWU) INTERROGATORY #9 List 1</u>

Issue 5 **Are the proposed spending levels for Sustaining, Development and Operations OM&A in 2013 and 2014 appropriate, including consideration of factors such as system reliability and asset condition?**

Interrogatory

Ref (1): Exhibit C1/Tab2/Sch 2/Page 15 of 72/Lines 1-8

> **<u>Condition</u>**
> **Without a further increase in replacement rates, the condition of the circuit breaker fleet is expected to degrade over the next 10 years due to the number of breakers exceeding their expected service lives. A 10-year forecast in Figure 6 shows that even with continuing at approximately the proposed replacement rate, the number of breakers in fair/poor condition will continue to increase from today. This is a leading indicator for equipment reliability. As such, prioritization of units for replacement will be critical and further increases in the program are expected beyond the test years.**

a) Does Hydro One expect a decrease in circuit breaker reliability in 2021 as a result of adopting its proposed replacement rate for this asset category? If so, what is the replacement rate for breakers that would be required to maintain the current level of breakers reliability in 2021?

Response

Hydro One does not expect circuit breaker reliability to degrade through 2021 if the proposed replacement plan is adopted in which the primary focus through the test years and beyond is air blast breaker replacements, due in part to their poor performance compared to other breaker types.

Forecasting circuit breaker reliability is challenging given the number of different variables and technologies involved. Hydro One is confident the approach of ongoing air blast breaker replacements, coupled with the targeted replacement of technically obsolete and poor performing breakers of other technologies will be able to counteract future reliability degradation as the asset base continues to age.

Power Workers Union (PWU) INTERROGATORY #10 List 1

Issue 5 **Are the proposed spending levels for Sustaining, Development and Operations OM&A in 2013 and 2014 appropriate, including consideration of factors such as system reliability and asset condition?**

Interrogatory

Ref (1): Exhibit C1/Tab2/Sch 2/Page 27 of 72 (Protection at a Glance)

The Chart in this reference presents historic and proposed levels of investments in protection systems as well as the 5-year and 10-year demographic outlook under historic and proposed levels of rates of replacement.

Ref (2): Exhibit C1/Tab 2/Sch 2/Page 33 of 72/Line 2

Protection Systems Portfolio	2009	2010	2011	2012 Forecast	2013 Test Year	2014 Test Year
# of replacements	259	283	389	380	400	450
% of Fleet	2.4	2.6	3.5	3.5	3.6	4.0
Capital ($M)	29	32	28.5	36.4	35.6	53.6
OM&A ($M)	10.4	9	11.3	10.5	11.8	12.5

a) Please provide estimates of the capital budgets and OM&A costs for protection systems for 2016 and 2021 assuming the demographic outlook and asset condition that Hydro One would expect at that time. Please provide the estimates assuming:
    i) The historic replacement rate of 310 protection systems per year (i.e. 2009- 2011 average per year); and
    ii) The proposed replacement rate of 410 protection systems per year (i.e. 2012-2014 average per year).
b) What are the reliability, environmental, safety and/or operational risk implications for 2016 and 2021 that Hydro One would expect as a result of keeping protection system sustaining replacements at the historic replacement rate of 310 protection systems per year (i.e. 2009-2011 average per year year) compared to the proposed replacement rate of 410 protection systems per year (i.e. 2012-2014 average per year)?
c) What would be the replacement rate to achieve a target of 0% of the protection systems beyond EOL (i.e. 0% EOL target) in 2021?
d) What would be the annual capital expenditures and OM&A associated with (c) above, i.e., 0% EOL target?
e) Please describe the resourcing constraints, if any, that Hydro One is currently facing to meet:
    i) The proposed replacement rate for protection systems;
    ii) The replacement rate for protection systems to achieve a 0% EOL target.
f) If Hydro One is facing resourcing constraints to achieve the proposed replacement rate for protection systems, please describe the actions that Hydro One is implementing to tackle such resourcing constraints.

Response

a) The capital and OM&A costs for the Current and Proposed investment levels are presented in the Protections at a Glance chart in Exhibit C1, Tab 2, Schedule 2, page 27. Although capital and OM&A budgets for years 2016 and 2021 are outside the scope of the current application, the cost levels in the referenced chart can be used as a basis of cost estimate projection.

   i) Continuation of a replacement rate of 310 protections per year would result in capital and OM&A costs similar to the 3 year historical average.
   ii) Proposed replacement rate of 410 protections per year would result in capital and OM&A costs that are similar to costs shown in the proposed investment in Exhibit C1, Tab 2, Schedule 2, page 27.

b) The consequences of keeping protections sustainment replacements at the historic replacement rate of 310 protections per year compared to the proposed replacement rate of 410 protections per year would be an increased and continually increasing proportion of protections being beyond their expected service life. Operating a larger proportion of protections beyond their expected service life will increase OM&A costs based on an expected increase in demand corrective work. This scenario would also increase the risk of unplanned equipment outages due to unreliable protections and would lead to equipment catastrophic failures due to uncleared faults. The results of this scenario would increase the risk of impacts to reliability, safety, environment and operations in future years (e.g. 2016 and 2021) as described in Exhibit C1, Tab 2, Schedule 2, pages 26 to28.

c) Based on the demographics of protections, to eliminate all protective relays that are currently operating beyond their expected service life by 2021 would require an annual replacement rate of approximately 40% higher than the proposed annual replacement rate. It should be noted that assessment of assets at their expected service life is not the only challenge, or factor in determining protections replacements. There are protections that are not at their expected service life that require replacement due to other circumstances such as system expansion (adding new stations), change of protection methodology (i.e. from distance to line differential) and design deficiencies that become apparent years after protections are placed in-service.

d) It is difficult to estimate the required capital expenditures associated with the scenario in c) due to other dependencies such as coordination with other capital and OM&A work and the ability to coordinate a higher concentration of planned outages required to carry out such an accelerated program. For this scenario, approximately 40% in capital beyond the proposed costs would be expected. The OM&A expenditures would be expected to decline over time as demand corrective work typically associated with equipment age and condition, would subside. Preventive maintenance would also decline over time as IEDs allow for longer maintenance intervals than older vintages of protections. Additional OM&A reduction would also come over time from the ability to remotely interrogate IED based protections for the purpose of event analysis thereby reducing reliance on field personnel to support analysis.

e) (i) (ii) Hydro One has successfully demonstrated the ability to complete the proposed replacement rate over the 2012-2014 period. The major factors that impact future work program execution along with actions that Hydro One has taken to increase volume of work are described in the pre-filed evidence on Work Execution Strategy as Exhibit A, Tab 15, Schedule 6. Hydro One is not recommending for the test years, a replacement rate where 0% of the inventory would be beyond expected service life . This would require an acceleration of the work execution strategy as presented in the reference exhibit.

f) See response under part e).

Power Workers Union (PWU) INTERROGATORY #11 List 1

Issue 5 **Are the proposed spending levels for Sustaining, Development and Operations OM&A in 2013 and 2014 appropriate, including consideration of factors such as system reliability and asset condition?**

Interrogatory

Ref (1): Exhibit C1/Tab2/Sch 2/Page 31 of 72/Lines 1-9/Figure 12

Figure 12 indicates that forced outage frequency remains significantly above the CEA 5 year moving average and Hydro One states that the demographics and increase in defects as demonstrated in Figure 11 (Exhibit C1/Tab 2/Sch 2/Page 30); require continued investments to maintain the current trend.

a) Does Hydro One expect protection forced outage frequency close to the current CEA 5 year average? If not, what would be the replacement rate required to achieve the current CEA benchmark in 2021?

Response

Practically, there are many factors that result in year over year forced outage performance variations as illustrated in Exhibit C1, Tab 2, Schedule 2 page 31, Figure 12. It would be a reasonable goal to be comparable to the CEA forced outage frequency performance average. However, performance serves as only one of several inputs considered in Hydro One's investment plans pertaining to asset replacements. These types of performance comparisons provide relative and directional trend information for Hydro One to compare end results. These considerations are presented in more detail in Exhibit C1, Tab 2, Schedule 2, pages 26 – 33.

Power Workers Union (PWU) INTERROGATORY #12 List 1

Issue 5 **Are the proposed spending levels for Sustaining, Development and Operations OM&A in 2013 and 2014 appropriate, including consideration of factors such as system reliability and asset condition?**

Interrogatory

Ref (1): Exhibit C1/Tab2/Sch 2/Page 35 of 72 (Underground Cables at a Glance)

The Chart in this reference presents historic and proposed levels of investments in Underground Cables as well as 5-year and 10-year demographic outlook under historic and proposed levels of rates of replacement.

Ref (2): Exhibit C1/Tab 2/Sch 2/Page 43 of 72/Lines 23-24

Cable Portfolio – Historical & Proposed	2009	2010	2011	2012	2013	2014
Capital – Replacement (km)	0	0	0	0	5.0	6.2
Capital – Replacement (% of fleet)	0	0	0	0	1.7	2.1
Capital ($M Net)	0.2	1.0	0.6	2.6	30.8	54.5
OM&A ($M Net)	4.4	4.0	6.6	3.6	4.3	4.4

Ref (3): Exhibit C1/Tab 2/Sch 2/Page 39 of 72/Lines 17-21 and Page 40/Figures 14-15

In reference to Figures 14 & 15, Hydro One states that although there has been an improvement in forced outage frequency, the duration of each occurrence over the past 5 years is increasing as are the corrective maintenance costs. This is representative of problems becoming more serious. Considering the deteriorating condition and demographics of the fleet, an increase in the rate of replacement is required to maintain the current forced outage frequency.

a) Please provide estimates of the capital budgets and OM&A costs for underground cables by 2016 and 2021 assuming the demographic outlook and asset condition that Hydro One would expect at that time. Please provide the estimates assuming:
   i) The historic replacement rate of 0 kilometres of underground cables per year (i.e. 2009-2011 average per year); and
   ii) The proposed replacement rate of 3.7 kilometres of underground cables per year (i.e. 2012-2014 average per year).
b) What are the reliability, safety and/or operational risk implications for 2016 and 2021 that Hydro One would expect as a result of keeping underground cables sustaining replacements at the historic replacement rate of 0 kilometres per year (i.e. 2009-2011 average per year) compared to the proposed replacement rate of 3.7 kilometres per year (i.e. 2012-2014 average per year)?
c) What would be the replacement rate to achieve a target of 0% of the underground cables beyond EOL (i.e. 0% EOL target) for 2021?

d) What would be the annual capital expenditures and OM&A associated with (c) above?
e) Please describe the resourcing constraints, if any, that Hydro One is currently facing to meet:
   i) The proposed replacement rate for underground cables;
   ii) The replacement rate for underground cables to achieve a 0% EOL target.
f) If Hydro One is facing resourcing constraints to achieve the proposed replacement rate for underground cables, please describe the actions that Hydro One is implementing to tackle such resourcing constraints.
g) Please confirm that the proposed replacement rate is required to maintain the current forced outage frequency of underground transmission cables and the average duration of each occurrence as well.

Response

a) The capital and OM&A costs for the historic and proposed investment levels are presented in the Underground Cables at a Glance chart in Exhibit C1, Tab 2, Schedule 2, page 35. Although capital and OM&A budgets for years 2016 and 2021 are outside the scope of the current application, the cost levels in the referenced chart can be used as a basis of cost estimate projection.

   i. Continuation of a replacement rate of 0 kilometers of underground cables per year would cost very little capital dollars similar to the 3 year historic average, but overtime the OM&A costs would likely significantly increase as a result of corrective work that would be needed for underground cables whose condition would continue deteriorating.
   ii. Proposed replacement rate of 3.7 kilometers per year would result in capital costs that are similar to the costs shown in the proposed investment in Exhibit C1, Tab 2, Schedule 2, page 35, and OM&A costs that are slightly less than the OM&A shown in the proposed investment over the 5 to 10 year period as a result of less corrective and demand work as cables are replaced.

b) The consequence of keeping the underground cable replacements at the historic replacement rate of 0 kilometers per year compared to the proposed replacement rate of 3.7 kilometers per year would be an increased and continually increasing proportion of underground cables exceeding their expected service life. Operating a larger proportion of underground cables beyond their expected service life will increase the risk of unplanned outages and underground cable failures. The result of this scenario would increase the risk of impacts to reliability, safety, and the environment in future years (e.g. 2016 and 2021) as described in Exhibit C1, Tab 2, Schedule 2, pages 34 and 36.

c) Based on demographics of underground cables alone, to eliminate all underground cables beyond their expected service life by 2021 would require an annual replacement rate of approximately 3 times the proposed replacement rate of 3.7 kilometers per year. However, demographics alone do not determine the requirement for underground cable replacements. Other factors are considered as part of this assessment (refer to Exhibit C1, Tab 2, Schedule 2, page 34 lines 24-26).

d) It is difficult to estimate the required capital expenditures associated with the scenario in c) due to other dependencies, such as coordination with other capital and OM&A work and the ability to coordinate a higher concentration of planned outages required to carry out such an accelerated work program. Capital costs on an order of magnitude of approximately three times the proposed costs would be expected. The OM&A expenditures would be expected to decline as corrective work, typically associated with equipment age and usage, would subside.

e) (i) and (ii) The major factors that impact future work program execution along with actions that Hydro One has taken to increase volume of work are described in the pre-filed evidence on Work Execution Strategy as Exhibit A, Tab 15, Schedule 6. Hydro One is not recommending for the test years, a replacement rate where 0% of the inventory would be beyond expected service life. This would require an acceleration of the work execution strategy as presented in the reference exhibit

f) See response for part e).

g) Hydro One submits that the proposed replacement rate over the test years will maintain or slightly improve the current forced outage frequency of the underground cables but will likely improve the forced outage duration as a result of removing the worst cables from the system.

<u>Power Workers Union (PWU) INTERROGATORY #13 List 1</u>

Issue 5 **Are the proposed spending levels for Sustaining, Development and Operations OM&A in 2013 and 2014 appropriate, including consideration of factors such as system reliability and asset condition?**

<u>Interrogatory</u>

Ref (1): Exhibit C1/Tab2/Sch 2/Page 55 of 72 (Steel Structures at a Glance)

The Chart in this reference presents historic and proposed levels of investments in Steel Structures as well as the 5-year and 10-year demographic outlook under historic and proposed levels of rates of replacement.

Ref (2): Exhibit C1/Tab 2/Sch 2/Page 64 of 72/Line 6

Tower Portfolio - Historic Trend	2007	2008	2009	2010	2011	2012	2013	2014
Capital – Coating/Refurb (quantity)	73	176	71	33	0	200	350	350
Capital – Coating/Refurb (% of Fleet)	0.1	0.4	0.1	0.1	0	0.4	0.7	0.7
Capital – Replacements (quantity)	0	0	0	0	0	16	4	4
Capital – Replacements (% of Fleet)	0	0	0	0	0	0.03	0.01	0.01
Capital ($M)	1.6	1.8	2.5	2.9	0.6	8.7	14.6	14.5
OM&A ($M)	3.3	5.0	5.1	3.6	4.7	4.8	4.8	5.0

a) Please provide estimates of the capital budgets and OM&A costs for steel structures for 2016 and 2021 assuming the demographic outlook and asset condition that Hydro One would expect at that time. Please provide the estimates assuming:
   i) The historic replacement/refurbishment rate of 35 steel structures per year (i.e. 2009-2011 average per year); and
   ii) The proposed replacement/refurbishment rate of 308 steel structures per year (i.e. 2012-2014 average per year).
b) What are the reliability, safety, environmental and/or operational risk implications for 2016 and 2021 as a result of keeping steel structures sustaining replacements at the historic replacement/refurbishment rate of 35 units per year (i.e. 2009-2011 average per year year) compared to the proposed replacement/refurbishment rate of 308 units per year (i.e. 2012-2014 average per year)?
c) What would be the replacement rate to achieve a target of 0% of the steel structures beyond EOL (i.e. 0% EOL target) in 2021?
d) What would be the annual capital expenditures and OM&A associated with (c)?
e) Please describe the resourcing constraints, if any, that Hydro One is currently facing to meet:
   i) The proposed replacement/refurbishment rate for steel structures; and
   ii) The replacement/refurbishment rate for steel structures to achieve a 0% EOL target.

f) If Hydro One is facing resourcing constraints to achieve the proposed replacement/refurbishment rate for steel structures, please describe the actions that Hydro One is implementing to tackle such resourcing constraints.

Response

a) The capital and OM&A costs for the historic and proposed investment levels are presented in the Steel Structures at a Glance chart in Exhibit C1, Tab 2, Schedule 2, page 55. Although capital and OM&A budgets for years 2016 and 2021 are outside the scope of the current application, the cost levels in the referenced chart can be used as a basis of cost estimate projection.

   i. Continuation of a refurbishment/replacement rate of 35 structures per year would result in capital and OM&A costs similar to the 3 year historic average.
   ii. Proposed refurbishment/replacement rate of 308 steel structures per year would result in capital and OM&A costs that are similar to the costs shown in the proposed investment in Exhibit C1, Tab 2, Schedule 2, page 55.

b) The consequence of keeping the steel structure refurbishments/replacements at the historic rate of 35 structures per year compared to the proposed refurbishments/replacements rate of 308 structures per year would be an increased and continually increasing proportion of steel structures exceeding their expected service life. Operating a larger proportion of steel structures beyond their expected service life will increase the risk of unplanned outages and structure failures. The result of this scenario would increase the risk of impacts to reliability, safety, and the environment in future years (e.g. 2016 and 2021) as described in Exhibit C1, Tab 2, Schedule 2, pages 54 and 56.

c) Based on demographics of steel structures alone, to eliminate all steel structures beyond their expected service life by 2021 would require an annual refurbishment/replacement rate of approximately 3 times the proposed refurbishment/replacement rate of 308 steel structures per year. However, demographics alone do not determine the requirement for steel structure refurbishment/replacements.

d) It is difficult to estimate the required capital expenditures associated with the scenario in c) due to other dependencies, such as coordination with other capital and OM&A work and the ability to coordinate a higher concentration of planned outages required to carry out such an accelerated work program. Capital costs on an order of magnitude of approximately three times the proposed costs would be expected. The OM&A expenditures would remain relatively constant as assessments, inspections and patrols continue to be carried out.

e) i) ii) The major factors that impact future work program execution along with actions that Hydro One has taken to increase volume of work are described in the pre-filed evidence on Work Execution Strategy as Exhibit A, Tab 15, Schedule 6. Hydro One is not recommending for the test years, a replacement rate where 0% of the inventory would be beyond expected service life. This would require an acceleration of the work execution strategy as presented in the reference exhibit.

f) See response under item e).

Power Workers Union (PWU) INTERROGATORY #14 List 1

Issue 5 **Are the proposed spending levels for Sustaining, Development and Operations OM&A in 2013 and 2014 appropriate, including consideration of factors such as system reliability and asset condition?**

Interrogatory

Ref (1): Exhibit C1/Tab2/Sch 2/Page 67 of 72 (Conductors at a Glance)

The Chart in this reference presents historic and proposed levels of investments in Conductors as well as the 5-year and 10-year demographic outlook under historic and proposed levels of rates of replacement.

Ref (2): Exhibit C1/Tab 2/Sch 2/Page 72 of 72/Lines 20-21

Conductor Portfolio – Historical & Proposed	2009	2010	2011	2012	2013	2014
Capital – circuit km	30	30	37	22	75	95
Capital - % of fleet	0.1	0.1	0.13	0.08	0.26	0.33
Capital ($M Net)	**14.4**	**14.7**	**10.2**	**8.6**	**36**	**37.5**
OM&A ($M Net)	8.4	7.3	10.6	10.6	12.8	13.6

Ref (3): Exhibit C1/Tab 2/Sch 2/Page 70/Figure 31 (Conductor Forced Outage Duration)

In reference to Figure 31, Hydro One states (Page 70, Line 10 / Page 71, Line 2) that the forced outage duration displayed in Figure 31 demonstrates that conductor outage duration has increased over the last 10 years. This is a measure of the severity of the defects that caused the circuit to be forced from service. This trend is expected to continue given the demographics and condition of the fleet.

a) Please provide estimates of the capital budgets and OM&A costs for conductors for 2016 and 2021 assuming the demographic outlook and asset condition that Hydro One would expect at that time. Please provide the estimates assuming:
   i) The historic replacement rate of 32 kilometres of conductors per year (i.e. 2009-2011 average per year); and
   ii) The proposed replacement rate of 64 kilometres of conductors per year (i.e. 2012-2014 average per year).
b) As per Ref (2), please provide the reasons for the drop off of the projected replacement rate for conductors from 37 km in 2011 to 22 km in 2012. Was the 2012 drop off not a result of Hydro One's inability to go through with some of the planned work?
c) What are the reliability, safety, environmental and/or operational risk implications for 2016 and 2021 that Hydro One would expect as a result of keeping conductor sustaining replacements at the historic replacement rate of 32 kilometres per year (i.e.

2009-2011 average per year year) compared to the proposed replacement rate of 64 kilometres per year (i.e. 2012-2014 average per year)? Please describe the specific risk implications.

d) What would be the replacement rate to achieve a target of 0% of the conductors beyond EOL (i.e. 0% EOL target) in 2021?
e) What would be the annual capital expenditures and OM&A associated with (d)?
f) Please describe the resourcing constraints, if any, that Hydro One is currently facing to meet:
    i) The proposed replacement rate for conductors;
    ii) The replacement rate for conductors to achieve a 0% EOL target; and
    iii) The replacement rate for conductors to achieve the current percentage of conductors beyond EOL in 2021.
g) If Hydro One is facing resourcing constraints to achieve the proposed replacement rate for conductors, please describe the actions that Hydro One is implementing to tackle such resourcing constraints.
h) As per Ref (3), please confirm that at the proposed replacement rate for conductors Hydro One expects an increase of forced outage duration in 2021. What is the replacement rate for conductors that would be required to maintain the current level of reliability in 2021?

Response

a) The capital and OM&A costs for the historic and proposed investment levels are presented in the Conductors at a Glance chart in Exhibit C1, Tab 2, Schedule 2, page 67. Although capital and OM&A budgets for years 2016 and 2021 are outside the scope of the current application, the cost levels in the referenced chart can be used as a basis of cost estimate projection.

    i. Continuation of a replacement rate of 32 kilometers per year would result in capital and OM&A costs similar to the 3 year historic average.
    ii. Proposed replacement rate of 64 kilometers per year would result in capital and OM&A costs that are similar to the costs shown in the proposed investment in Exhibit C1, Tab2, Schedule 2, Page 67.

b) There were two projects (A6P line refurbishment and the B10/B20H conductor replacement) that had been planned for execution in 2011/2012. The accomplishment difference between 2011 and 2012 is a result of addressing a greater percentage of the required km’s for the two projects in 2011; resulting in less kms required to be completed in 2012. All planned work will be completed on schedule.

c) The consequence of keeping the conductor replacements at the historic rate of 32 kilometers per year compared to the proposed replacement rate of 64 kilometers per year would be an increased and continually increasing proportion of conductors exceeding their expected service life. Operating a larger proportion of conductors beyond their expected service life will increase the risk of unplanned outages and conductor failures. The result of this scenario would increase the risk of impacts to reliability, safety, and the environment in future years (e.g. 2016 and 2021) as described in Exhibit C1, Tab 2, Schedule 2, page 68.

d) Based on demographics of conductors alone, to eliminate all conductors beyond their expected service life by 2021 would require an annual replacement rate of approximately 14 times the proposed replacement rate. However, demographics alone do not determine the requirement for conductor replacements as there are other influencing factors.

e) It is difficult to estimate the required capital and OM&A expenditures associated with the scenario in d) due to other dependencies, such as coordination with other capital and OM&A work and the ability to coordinate a higher concentration of planned outages required to carry out such an accelerated work program. Capital costs on an order of magnitude of approximately 14 times the proposed costs would be expected. The OM&A expenditures would remain relatively constant as assessments, inspections and patrols continue to be carried out.

f) (i) (ii) (iii) The major factors that impact future work program execution along with actions that Hydro One has taken to increase volume of work are described in the pre-filed evidence on Work Execution Strategy as Exhibit A, Tab 15, Schedule 6. Hydro One is not recommending for the test years, a replacement rate where 0% of the inventory would be beyond expected service life. This would require an acceleration of the work execution strategy as presented in the reference exhibit.

g) See response under item f).

h) Hydro One submits that the proposed replacement rate over the test years will maintain the current forced outage duration of conductors over that period. It would be expected that in order to maintain the current forced outage duration of conductors in 2021, based on demographics alone, conductor replacements will need to increase in the future.

Power Workers Union (PWU) INTERROGATORY #15 List 1

Issue 5 **Are the proposed spending levels for Sustaining, Development and Operations OM&A in 2013 and 2014 appropriate, including consideration of factors such as system reliability and asset condition?**

Interrogatory

Ref (1): Exhibit C1/Tab2/Sch 2/Page 45 of 72 (Tx Wood Poles at a Glance)

The Chart in this reference presents historic and proposed levels of investments in wood poles as well as the 5-year and 10-year demographic outlook under historic and proposed levels of rates of replacement.

Ref (2): Exhibit C1/Tab 2/Sch 2/Page 53 of 72/Line 17

Wood Pole Portfolio – Historic & Proposed	2007	2008	2009	2010	2011	2012	2013	2014
Capital - # of replacements	817	774	811	880	862	850	850	850
Capital - % of fleet replaced	1.9	1.8	1.9	2.1	2.1	2.0	2.0	2.0
Capital ($M Net)	**24.8**	**21.8**	**28.0**	**29.6**	**30.1**	**27.2**	**28.0**	**28.8**
OM&A ($M Net)	**2.5**	**3.6**	**3.5**	**3.5**	**2.9**	**4.5**	**4.6**	**4.8**

a) Please provide estimates of the capital budgets and OM&A costs for transmission wood poles for 2016 and 2021 assuming the demographic outlook and asset condition that Hydro One would expect at that time. Please provide the estimates assuming the proposed replacement/refurbishment rate of 850 wood poles per year (i.e. 2012-2014 average per year).
b) What would be the replacement rate to achieve a target of 0% of the wood poles beyond EOL (i.e. 0% EOL target) in 2021?
c) What would be the annual capital expenditures and OM&A associated with (b) above?
d) What would be the replacement rate to maintain the current percentage of wood poles beyond EOL in 2021?
e) What would be the annual capital expenditures and OM&A associated with (d) above?
f) Please describe the resourcing constraints, if any, that Hydro One is currently facing to meet:
   i) The proposed replacement rate for wood poles;
   ii) The replacement rate for wood poles to achieve a 0% EOL target; and
   iii) The replacement rate for wood poles to maintain the current percentage of wood poles beyond EOL in 2021.
g) If Hydro One is facing resourcing constraints to achieve the proposed replacement rate for wood poles, please describe the actions that Hydro One is implementing to tackle such resourcing constraints.

Response

a) The capital and OM&A costs for the historic and proposed investment levels are presented in the Wood Poles at a Glance chart in Exhibit C1, Tab 2, Schedule 2, page 45. Although capital and OM&A budgets for years 2016 and 2021 are outside the scope of the current application, the cost levels in the referenced chart can be used as a basis of cost estimate projection. Continuation of a replacement rate of 850 wood poles per year would be estimated to cost capital and OM&A dollars similar to the 3 year proposed investment in Exhibit C1, Tab 2, Schedule 2, page 45, with some capital reductions through 2021 as the remaining Gulfport structures are replaced.

b) Based on demographics of wood poles alone, to eliminate all wood poles beyond their expected service life by 2021 would require an annual replacement rate of approximately 1.5 times the proposed replacement rate of 850 wood poles per year. However, demographics alone do not determine the requirement for wood pole replacements.

c) It is difficult to estimate the required capital and OM&A expenditures associated with the scenario in b) due to other dependencies, such as coordination with other capital and OM&A work and the ability to coordinate a higher concentration of planned outages required to carry out such an accelerated work program. Capital costs on an order of magnitude of approximately 1.5 times the proposed costs would be expected. The OM&A expenditures would show a slight decrease relative to the proposed investment over the 10 year period as corrective work would subside, while patrols, inspections and assessment activities would continue.

d) To maintain the current percentage of wood poles beyond their expected service life in 2021, the annual replacement rate would decrease as compared to the proposed replacement rate of 850 wood poles per year.

e) Capital costs would decrease proportional to the decrease in wood pole replacements. The OM&A expenditures would likely show an increase relative to the proposed OM&A investment as an increase in corrective work would be expected.

f)

i. Hydro One is not facing any resource constraints to replace wood poles at the proposed rate and has successfully been achieving approximately this number of wood pole replacements.

ii. The major factors that impact future work program execution along with actions that Hydro One has taken to increase volume of work are described in the pre-filed evidence on Work Execution Strategy as Exhibit A, Tab 15, Schedule 6. Hydro One is not recommending for the test years, a replacement rate where 0%

of the inventory would be beyond expected service life. This would require an acceleration of the work execution strategy as presented in the reference exhibit.

iii. Hydro One would not face any resource constraints in this scenario.

g) See response under item f).

Power Workers Union (PWU) INTERROGATORY #16 List 1

Issue 5 **Are the proposed spending levels for Sustaining, Development and Operations OM&A in 2013 and 2014 appropriate, including consideration of factors such as system reliability and asset condition?**

Interrogatory

Ref (1): Asset Condition Assessment, EB-2005-0501, Exhibit D1/Tab 2/Sch 1
Ref (2): Transmission Assets and Investment Structure, EB-2010-0002, Exhibit C1/Tab 2/Sch 2
Ref (3): Transmission Assets and Sustaining Investment Overview, EB-2012- 0031, Exhibit C1/Tab 2/Sch 2
Ref (4): Transmission 10 Year Outlook, EB-2012-0031, Exhibit A/Tab 13/Sch 2

a) Please fill out the following table. Please also provide references for the sources of data or provide explanation on derivation of numbers/percentages.

	Asset Class	Transformers	Breakers	Protection and Control systems	Underground Cables	Towers	Conductors	Wood Pole Structures
(1)	*Fleet Size - Number of Units 2012*							
(2)	*Expected End-of-life (EOL)*							
(3)	*Historic Replacement Rate -2009 - 2011 Average replacement rate*							
(4)	*Proposed Replace Rate - average replacement per year 2012 -2014*							
(5)	*% of assets beyond EOL – 2006*							
(5)	*% of assets beyond EOL – 2009*							
(7)	*% of assets beyond EOL – 2012*							
	% of assets beyond EOL – 2021 Assuming historical average replacement rate(i.e. 2009-2011)							
(8)	*% of assets beyond EOL – 2021 Assuming proposed replacement rate(i.e. avg. 2012-2014)*							
(9)	*% of assets in "poor and "very poor condition – 2006*							
(10)	*% of assets in "poor and "very poor condition – 2009*							
(11)	*% of assets in "poor and "very poor condition – 2012*							
(12)	*% of assets in "poor and "very poor condition – 2021 Assuming historical average replacement rate(i.e. 2009-2011)*							
(13)	*% of assets in "poor and "very poor condition – 2021 Assuming proposed replacement rate(i.e. 2012-2014)*							
(14)	*Equipment Frequency of forced outages - comparison to CEA Average ("better" or "worse")*							

b) Figure 5.3b of the Transmission 10 Year Outlook (Ref 4) provides asset condition of circuit breakers as of 2011. Please provide the numbers and the respective percentages of breakers in "very good", "good", "fair", "poor" and "very poor" conditions.

c) Figure 5.4b of the Transmission 10 Year Outlook (Ref 4) provides asset condition of the overhead conductors as of 2011. Please provide the kilometers and the respective percentages of overhead conductors in "very good", "good", "fair", "poor" and "very poor" conditions.

d) Figure 5.5b of the Transmission 10 Year Outlook (Ref 4) provides asset condition of underground cables as of 2011. Please provide kilometers and the respective percentages of underground cables in “very good”, “good”, “fair”, “poor” and “very poor” conditions.

e) Figure 5.6b of the Transmission 10 Year Outlook (Ref 4) provides asset condition of the steel tower structures as of 2011. Please provide the numbers and the respective percentages of steel tower structures in "very good", "good", "fair", "poor" and "very poor" conditions.

f) Figure 5.7b of the Transmission 10 Year Outlook (Ref 4) provides asset condition of the population of wood poles as of 2011. Please provide the numbers and the respective percentages of wood poles in "very good", "good", "fair", "poor" and "very poor" conditions.

g) Figure 5.9b of the Transmission 10 Year Outlook (Ref 4) provides asset condition of the protection and control relay portfolio as of 2011. Please provide the numbers and the respective percentages of protection and control relays in "very good", "good", "fair", "poor" and "very poor" conditions.

h) Is Hydro One satisfied with its current customer reliability levels?

i) Does Hydro One monitor the percentage of time (and year to year trend) the transmission system is operating such that a single contingency (where it is designed to operate under double contingency standard) would result in increased customer reliability deterioration? If so, please provide the historical trend of the percentage of the time the transmission system is operating such that a single contingency would result in customer outage or derating.

Response

a) The table of values requested is provided below. References for the sources of data provided in the notes section below the table.

#	Asset Class	Transformers	Breakers	Protections	Cables	Towers	Conductors	Wood Poles
1	Fleet (# units)	719	4,490	11,013	291 circuit km	49,890	28,636	42,007
2	ESL (years)	50	40 - 55	25 - 40	50	80 - 100	70	40 - 50
3	Historic Replacement Rate (%/yr)	1.4	1.6	2.8	0	0	0.1	2
4	Proposed Replacement Rate (%/yr)	2.6	2.1	3.7	1.3	0.01	0.2	2
5	% of assets beyond ESL 2006	17	3		6			16
6	% of assets beyond ESL 2009	24	6		18			21
7a	% of assets beyond ESL 2012	21	8	31	19	15	16	27
7b	% of assets beyond ESL 2021 assuming historic rate	30	8	25	36	25	31	13
8	% of assets beyond ESL 2021 assuming proposed rate	18	2	16	23	19	30	13
9	% in "poor and very poor" 2006	3	1	10	0		2	10
10	% in "poor and very poor" 2009							
11	% in "poor and very poor" 2012	10	16	17	6	1	16	10
12	% in "poor and very poor" 2021 assuming historical rate							
13	% in "poor and very poor" 2021 assuming proposed rate							
14	Equipment Frequency of forced outages compared to CEA average	Worse	Worse	Worse	Worse	Better	Better	Worse

Notes:

1. The 2012 and future year data are from pre-filed evidence: Exhibit C1, Tab 2, Schedule 2; Exhibit D1, Tab 3, Schedule 2; Exhibit A, Tab 13, Schedule 2; The 2009 year data are from Appendix A of Exhibit C1, Tab 02, Schedule 2 of EB-2010-0002. The 2006 year data are from Appendix A of Exhibit D1, Tab 2, Schedule 1 of EB-2005-0501.
2. Table cells that are blank are data that are not readily available.
3. With the exception of Breakers and Cables, the “At a Glance Tables” in Exhibit C1, Tab 2, Schedule 2 were not updated as part of the August 15 update.

b-g) The information requested in parts b) through g) are summarized in the following table.

	Very Good		Good		Fair		Poor		Very Poor	
Asset Class	**#**	**%**	**#**	**%**	**#**	**%**	**#**	**%**	**#**	**%**
Transformers	373	52%	203	28%	69	10%	53	7%	21	3%
Circuit Breakers	950	21%	1821	40%	1,020	23%	671	15%	28	1%
P&C	6,400	58%	463	4%	2,250	20%	1,600	15%	300	3%
Cables			220	76%	53	18%	18	6%		
Towers			47,890	96%	1,734	3%	266	1%		
Conductors			14,436	50%	9,700	34%	4,500	16%		
Wood Poles			32,607	78%	5,700	13%	3,700	9%		

Notes:

1. The data is from Exhibit A, Tab 13, Schedule 2.

h) Hydro One measures its customer reliability levels using frequency and duration of multi-circuit delivery point interruptions. As outlined in Exhibit A, Tab 16, Schedule 1 page 11, these measures provide a basis to benchmark with comparable utilities in Canada. The benchmarking performed by the Canadian Electricity Association shows Hydro One is in the top quartile on frequency and duration of multi-circuit delivery point interruptions relative to comparable Canadian utilities. Based on leading indicators used by Hydro One, in order to maintain this level of reliability increased investments will be required as outlined in the evidence.

i) No, Hydro One does not directly measure the percentage of time the transmission system elements are in a single contingency state (when designed to dual contingency standards) and an outage occurs. Hydro One does have operating procedures and processes to assess the level of risk that an equipment outage presents to its customers, and Hydro One will take the necessary actions to mitigate the identified risk/contingency.

School Energy Coalition (SEC)*INTERROGATORY #8 List 1*

Issue 5 **Are the proposed spending levels for Sustaining, Development and Operations OM&A in 2013 and 2014 appropriate, including consideration of factors such as system reliability and asset condition?**

Interrogatory

[C1-2-1/p.1]
How does the Applicant operationally allocate OM&A costs to OM&A functions (eg Sustaining, Development, and Operations etc).

Response

The process used for Hydro One's Investment Plan Development is outlined in Exhibit A, Tab 15, Schedule 3. Sections 2.0, 3.0, and 4.0 speak to the investment plan development for Sustaining, Development and Operations areas respectively.

School Energy Coalition (SEC)*INTERROGATORY #9 List 1*

Issue 5 Are the proposed spending levels for Sustaining, Development and Operations OM&A in 2013 and 2014 appropriate, including consideration of factors such as system reliability and asset condition?

Interrogatory

[C1-2-2/p.16]
With respect to Circuit Breakers:

a. Please explain the decrease in Sustainment replacements in the Bridge Year.
b. Please explain the increase capital cost per replacement in 2012-2014 compared to 2010-2011?

Response

a) Please refer to Exhibit I, Tab 5, Schedule 1.08 Staff 30.

b) Please refer to Exhibit I, Tab 5, Schedule 1.07 Staff 29.

School Energy Coalition (SEC)*INTERROGATORY #10 List 1*

Issue 5 **Are the proposed spending levels for Sustaining, Development and Operations OM&A in 2013 and 2014 appropriate, including consideration of factors such as system reliability and asset condition?**

Interrogatory

[C1-2-2/p.25]
With respect to Transformers, please explain the decrease in Sustainment replacements in the Bridge Year compared to 2011.

Response

Please refer to Exhibit I, Tab 5, Schedule 8.04 PWU 5.

School Energy Coalition (SEC)*INTERROGATORY #11 List 1*

Issue 5 Are the proposed spending levels for Sustaining, Development and Operations OM&A in 2013 and 2014 appropriate, including consideration of factors such as system reliability and asset condition?

Interrogatory

[C1-2-2/p.53]
With respect to the Wood Poles, please explain the increase in OM&A spending between the Bridge Year and the Test Year.

Response

Please refer to Exhibit I, Tab 5, Schedule 1.10 Staff 32.

School Energy Coalition (SEC) *INTERROGATORY #12 List 1*

Issue 5 **Are the proposed spending levels for Sustaining, Development and Operations OM&A in 2013 and 2014 appropriate, including consideration of factors such as system reliability and asset condition?**

Interrogatory

[C1-2-2/p.64]
With respect to the Tower Portfolio, please explain why there were no coating/refurbishments or replacements in 2011?

Response

There were no tower coatings/refurbishments in 2011 because the program was suspended in 2011 due to an internal joint health and safety committee (JHSC) review of work practices. This review has been completed and the program has resumed in 2012. For replacements, based on available condition data no standalone tower replacements were required prior to 2012.

School Energy Coalition (SEC) ***INTERROGATORY #13 List 1***

Issue 5 **Are the proposed spending levels for Sustaining, Development and Operations OM&A in 2013 and 2014 appropriate, including consideration of factors such as system reliability and asset condition?**

Interrogatory

[C1-3-1/p.5]
Please provide further details regarding which areas of Sustaining, Development and Operations, the Applicant reduced spending compared to the Board Approved amounts for 2011.

Response

Please see Exhibit I Tab 6 Schedule 5.02 VECC 31 part c).

School Energy Coalition (SEC) *INTERROGATORY #14 List 1*

Issue 5 **Are the proposed spending levels for Sustaining, Development and Operations OM&A in 2013 and 2014 appropriate, including consideration of factors such as system reliability and asset condition?**

Interrogatory

[C1-3-1/p.6]
Please provide further details regarding which areas of Sustaining, Development and Operations, the Applicant reduced spending compared to the Board Approved amounts for 2012.

Response

Please see Exhibit I, Tab 6, Schedule 5.02 VECC 31, part c)

School Energy Coalition (SEC) *INTERROGATORY #15 List 1*

Issue 5 **Are the proposed spending levels for Sustaining, Development and Operations OM&A in 2013 and 2014 appropriate, including consideration of factors such as system reliability and asset condition?**

Interrogatory

[C1-3-2/p.37]
Please provide a breakdown of the 'Facilities and Infrastructure Maintenance' budget for 2009 through 2014.

Response

Please refer to the table below for a breakdown of the 'Facilities and Infrastructure Maintenance' OM&A expenditures.

Facilities and Infrastructure Maintenance OM&A ($Millions)

Description	2009 Historic	2010 Historic	2011 Historic	2012 Bridge	2013 Test	2014 Test
Tx Switchyard Maintenance	8.4	7.2	8.5	5.8	7.2	7.4
Civil / Geotech Inspections and Assessments	0.1	0.2	0.1	0.2	0.4	0.4
Building Inspections & Maintenance	7.9	8.0	7.8	8.3	8.8	9.2
Roads, Bridges & Rlwys Inspection	0.5	0.3	0.5	0.3	0.4	0.4
Fencing, Guards, Gates Inspection	2.3	1.7	0.1	0.5	0.5	0.5
Utilities	2.0	1.9	2.8	3.0	3.3	3.4
Janitorial	1.9	1.3	2.2	2.4	2.4	2.2
Total	**23.1**	**20.6**	**22.0**	**20.5**	**23.0**	**23.5**

School Energy Coalition (SEC) *INTERROGATORY #16 List 1*

Issue 5 **Are the proposed spending levels for Sustaining, Development and Operations OM&A in 2013 and 2014 appropriate, including consideration of factors such as system reliability and asset condition?**

Interrogatory

[C1-3-2/p.39]
Please explain the decrease in site security at transmissions stations spending in 2014 compared to 2013.

Response

The difference in proposed site security OM&A spending in 2014 compared to 2013 is less than $100 thousand, and is due to minor differences in the cost and timing of work.

School Energy Coalition (SEC) *INTERROGATORY #17 List 1*

Issue 5 **Are the proposed spending levels for Sustaining, Development and Operations OM&A in 2013 and 2014 appropriate, including consideration of factors such as system reliability and asset condition?**

Interrogatory

[A-17-1/p7]
Please provide the derivation of the calculations contained in Table 1 and Table 2.

Response

Table 1 provides the cumulative annual savings in the four listed categories: non-Cornerstone OM&A and Capital, and Cornerstone specific OM&A and Capital. For the Cornerstone elements please see Exhibit D1, Tab 4, Schedule 3 for details. With regard to the non-Cornerstone Savings the following provides a further breakdown:

$M	2012	2013	2014
Tx OM&A is primarily made up of the following:			
• Renegotiated Inergi Contract	4.9	6.7	8.5
• WAN Consolidation	0.6	1.0	1.1
• Staffing flexibility	9.0	8.4	7.2
• leveraging technology	3.1	4.3	5.5
• process efficiencies	13.0	14.7	14.8
Tx Capital is primarily made up of the following:			
• Renegotiated Inergi Contract	0.4	1.3	2.2
• Rationalizing telecom assets	1.5	2.3	2.5
• Staffing flexibility	7.4	5.6	7.6
• leveraging technology	5.9	6.8	8.0
• process efficiencies	9.1	9.5	9.5

Table 2 provides the incremental calculation, one year minus the previous year, for the same categories.

Consumers Council of Canada (CCC) INTERROGATORY #8 List 1

Issue 5 **Are the proposed spending levels for Sustaining, Development and Operations OM&A in 2013 and 2014 appropriate, including consideration of factors such as system reliability and asset condition?**

Interrogatory

(Ex. C/T3/S 1/p. 2) Please recast Table I - Summary of OM&A Budget to include Board approved levels for 2009-2012.

Response

Please refer to Exhibit I, Tab 5, Schedule 10.07 CCC14

Consumers Council of Canada (CCC) INTERROGATORY #9 List 1

Issue 5 **Are the proposed spending levels for Sustaining, Development and Operations OM&A in 2013 and 2014 appropriate, including consideration of factors such as system reliability and asset condition?**

Interrogatory

(Ex. C/T3/S 1/p. 5) Please provide a more detailed explanation as to why there is a $11.1 variance in Shared Services and Other Costs between actual and Board approved amounts.

Response

2011 Board Approved versus 2011 Actual OM&A Expenditures
Shared Services & Other Costs ($M)

OM&A Categories	**2011 Board Approved**	**2011 Actual**	**Variance**
Real Estate	27.6	26.7	-0.9
Information Technology	68.6	57.6	-11.0
Asset Management	34.5	25.0	-9.5
Corporate Services*	51.6	45.6	-6.0
Total Change in Shared Services	**182.2**	**154.9**	**-27.4**
External Work Cost of Sales	14.9	12.8	-2.2
Overheads Recovered	-126.3	-105.5	20.8
Other Corporate Costs	-11.9	-18.5	-6.6
EB-2010-0002 Reduction	-13.9	0.0	13.9
Cornerstone Savings - Unclassified	-12.5	0.0	12.5
Net Change in Shared Services & Other Costs	**32.6**	**43.7**	**11.1**

* Corporate Services Includes Corporate Management, Controller, Treasury, Tax, Corporate Communications, Corporate Security, HR, Regulatory Affairs, General Counsel & Secretariat and Internal Audit

Consumers Council of Canada (CCC) INTERROGATORY #10 List 1

Issue 5 **Are the proposed spending levels for Sustaining, Development and Operations OM&A in 2013 and 2014 appropriate, including consideration of factors such as system reliability and asset condition?**

Interrogatory

(Ex. C1/T3/S2/p. 3) Please recast Table 1 -Sustaining OM&A- to include Board approved levels.

Response

Please refer to Exhibit I, Tab 5, Schedule 10.07 CCC 14.

Consumers Council of Canada (CCC) INTERROGATORY #11 List 1

Issue 5 **Are the proposed spending levels for Sustaining, Development and Operations OM&A in 2013 and 2014 appropriate, including consideration of factors such as system reliability and asset condition?**

Interrogatory

(Ex. Cl/T3/S1/p. 6) Sustaining OM&A actual expenditures are expected to be $25.2 million less than the Board approved levels. The explanation provided indicates that the lower level of spending was driven by the need to stay within the overall OM&A envelope approved by the Board in the last Decision, offset by an increase in Shared Services. Please explain in detail the process HONI undertook in order to reduce the expenditures in light of the Board's decision. Please provide copies of any correspondence between senior management and staff regarding the last decision. Specifically, what kind of direction was provided to staff in order to manage expenditures within the Board approved envelope?

Response

Please refer to Exhibit I, Tab 5, Schedule 1.03 Staff 23.

With respect to correspondence between senior management and staff regarding the last decision and what kind of direction was provided to staff in order to manage expenditures within the Board approved envelope, the following instructions were provided to staff through the Business Planning process:

"In its recent decision on Hydro One's 2011/2012 Transmission rate application, the Ontario Energy Board (OEB) disallowed the Bruce to Milton construction work in progress recovery, removed station protection upgrades for DG and transfer trip facilities; reduced OM&A envelope by 3% ($13M) and 4% ($18M) for 2011 and 2012 respectively, and further adjusted OM&A by $5M each year for HST and capital in 2011 budget and 2012 outlook for the impact of changes for cost of capital and AFUDC rate. It is clear from the OEB's comments in their decision that they expect Hydro One to focus its spending priorities.

Therefore, given the current environment Hydro One faces, the work program should be maintained at the lowest reasonable level to maintain safety and reliability while mitigating rate increases. It is important that all costs included in your 2012-16 business plan are necessary and supportable. All units will be asked to justify their 2012-16 planned expenditures and staffing levels and clearly explain in detail any variances vs. 2010 actuals for OM&A, Capital and headcount. However, before requesting an increase in your plan dollars, please review your activities and look for ways to accommodate the new workload within your existing structure. This could be accomplished through increased productivity or eliminating lower priority work. Detailed explanation and support is required for all cost increases and justification is required for any additional headcount over-and-above 2010 actual year-end headcount.

Since the results of this business planning process will form the basis of a two year submission for Distribution rates (2012 and 2013) in November 2011 and a two year submission for Transmission rates (2013 and 2014) in April 2012, it is important that all increases in costs are supported for the preparation of evidence. Clear and value added variance explanations are required. Explanations should go beyond stating the obvious, e.g. not enough to say "*higher non labour costs due to higher consultants*". Explanations should highlight key drivers (root causes) of changes in costs or headcount".

Financial Guidance related to Transmission OM&A levels was also stated as follows:

- 2012 OM&A envelope should equal to the 2012 OEB approved levels
- 2013 and 2014 OM&A envelope will be maintained as near as possible to 2012 OEB approved levels
- 2015-2016 Transmission OM&A should be maintained at the lowest reasonable level to maintain safety and reliability while mitigating rate increases

Consumers Council of Canada (CCC) INTERROGATORY #12 List 1

Issue 5 **Are the proposed spending levels for Sustaining, Development and Operations OM&A in 2013 and 2014 appropriate, including consideration of factors such as system reliability and asset condition?**

Interrogatory

(Ex. C1/T3/S 1 p. 6) Please explain in detail where the $25.2 million in reductions were made. Please identify all of the projects that were either cancelled or deferred.
(Ex. C1/T3/S2/p. 41) Please explain, in detail, why it is necessary to increase the Line Sustaining budget in 2013 and 2014 so significantly over historical levels. Please indentify how HONI is attempting to reduce these costs. Please explain what the pending FAC-003-2 NERC standard is and the status of that standard. To what extent are the increases in 2013 and 2014 related to this standard?

Response

Refer to Exhibit I, Tab 6, Schedule 5.02 VECC 31, part c) for further breakdown of the $25.2 million difference between the 2012 bridge year Sustaining OM&A versus the 2012 Board Approved from the EB-2010-0002 proceeding. Specific reductions were made in most work programs of Sustaining OM&A. The most significant reductions occurred in Power Equipment ($12 million), Ancillary Systems ($6 million), and Overhead Lines ($3 million).

The Lines Sustaining OM&A budget is increasing over historical levels for a number of reasons including the need to replace aging hardware such as u-bolts and dampers, carry out increased conductor sampling, as well as some increases in vegetation management as a result of the pending NERC FAC-003-2 standard. The increase over 2012 levels is primarily composed of an additional $2.5M to address aging hardware and an additional $2.4M to increase brush control and line clearing over 2012 accomplishments. In order to reduce these costs, Hydro One is making all efforts to bundle patrols/assessment activities with other activities where possible to achieve efficiencies.

FAC-003-2 is the pending NERC Vegetation Management Standard and its purpose is to improve the reliability of the electric transmission system by preventing vegetation related outages that could lead to cascading outages. The new pending regulatory requirement stipulated by this standard will require Hydro One to inspect all of its affected lines on an annual basis. These annual inspections have not been a part of Hydro One's practices in the past and result in incremental work in the order of $650 thousand per year in each of the test years. NERC has prepared a filing petition to FERC for approval of the standard, and it is currently being reviewed by the FERC board.

<u>Consumers Council of Canada (CCC) INTERROGATORY #13 List 1</u>

Issue 5 **Are the proposed spending levels for Sustaining, Development and Operations OM&A in 2013 and 2014 appropriate, including consideration of factors such as system reliability and asset condition?**

<u>Interrogatory</u>

(C1/T3/S3/p. 3) The 2013 and 2014 budgets for Technology Program- Transmission Studies is $3.6 million and $3.7 million respectively. The evidence indicates that the objectives of the program are to undertake advanced studies to assess and evaluate the feasibility of emerging technologies. Please provide a detailed budget for this program. Please indicate how HONI assesses the value of these expenditures. How does this program benefit ratepayers?
(C1/T3/S3/p. 8) Please provide a detailed budget for the Transmission Standards Program for 2013 and 2014.

<u>Response</u>

<u>Part A</u>
Planned budgets for 2013 ($3.6M) and 2014 ($3.7M) as identified for the Technology Program - Transmission Studies in Exhibit C1, Tab 3, Schedule 3 page 3 to 6 are detailed below:

1) EXTERNAL PROGRAM: ($3.4M/$3.5M for 2013/2014)

This program covers power delivery, utilization, safety and environmental studies. The objectives of these studies are to assess and evaluate the feasibility of emerging and existing grid technologies and practices in order to optimize grid reliability and performance as well as to comply with regulatory requirements. Examples of this program include: Lightning Performance on Overhead Line Conductors; Next Generation of Advanced Inspection and Sensor Technologies; Performance and Maintenance of High Temperature Low Sag Conductors; Testing and Commissioning of the IEC61850 Substation Platform; Determination and Evaluation of Acceptable Vibration Limits; Cyber Security and Privacy Technology Transfer and Industry Collaboration.

2) INTERNAL PROGRAM: ($0.15M/$0.15M for 2013/2014)

This program consists of one project initiated in 2012: Transformer Station Strain Bus Capability under Short Circuit Conditions for Safety and Reliability.

3) VEGETATION OPTIMIZATION: ($0.03M/$0.05M for 2013/2014)

This program consists of one multiyear project which covers the examination of alternative types of vegetation which may be used in transmission rights of ways with the objectives of improving operational and sustainment efficiency while protecting endangered species.

Hydro One assesses the value of expenditures by considering the contribution to the Corporate Strategic Objectives including transmission system reliability, compliance to regulatory and government initiatives, employee and public health and safety, and environmental protection. Hydro One also considers the degree of cost leveraging (historically 7-9 times) through partnerships in joint programs with industry, universities, research organizations and other utilities. All of these factors support benefits to ratepayers.

The benefits to ratepayers of this program over the long term include:

- More efficient system sustainment, development and operations contributing to lower costs;
- Sustained or improved reliability, safety, security and power quality;
- Improved customer information supporting energy conservation.

Part B

Planned budgets for 2013 ($6.4M) and 2014 ($7.0M) identified for the Transmission Standards Program in Exhibit C1 Tab 3 Schedule 3 on pages 7 to 9 are detailed below:

1) INTERNAL PROGRAM – 2013 $5.1M (84 Stds) ; 2014 $5.7M (92 Stds)

Development and revision of engineering design, construction, safety and security standards required for transmission system enhancement, productivity improvement, innovation, to enable renewable generation integration and to support the ADS evolution. Examples of the standards required are: Design Standards for IP / MPLS implementation at Hub Site and Remote stations; Design Standards for 500 kV 80kA Rigid Bus; Structural Design Criteria for Overhead Transmission Lines and Installation Details for the GE JMUX SONET Multiplexer used in DESN Stations.

2) EXTERNAL PROGRAM – 2013 $0.2M (3 Stds) ; 2014 $0.2M (3 Stds)

Development and revision of industry standards or studies by external consultants related to power quality, reliability and asset sustainment. Examples of the studies are: Grounding Standards in Vicinity of SVC and Arc Flash Study.

3) INTERNAL PROGRAM – 2013 $0.6M (14 Stds) ; 2014 $0.6M (14 Stds)

Development and revision of functional standards for transmission systems including lines, stations, protection, control & telecommunication equipment and support for major transmission projects and the ADS. Examples of the standards required are: Functional Requirements for IED Data Extraction; Functional Standards for TX Mobile Unit Transformer / Substation design, connectivity, protection and control; Functional Requirements for Transformer Monitoring and Functional Standards for Fence, Equipment and Structure Grounding and Bonding methods.

4) INTERNAL PROGRAM – 2013 $0.5M (14 Stds) ; 2014 $0.5M (14 Stds)

Development and revision of transmission commissioning and maintenance procedures and standards for grid planning and operations and station maintenance. This includes standards for major equipment, protection & control, switching, voltage controls and regulatory compliance. Examples of the standards required are: Back to Back Feeder Switcthing (TIPS module) Commissioning standard; Commissioning Procedure for BES Station LAN with Modular Assemblies; Breaker Timing Test Interpretation Guidelines and Commissioning Procedure for Transformers with 2nd Harmonic Component.

Consumers Council of Canada (CCC) INTERROGATORY #14 List 1

Issue 5 Are the proposed spending levels for Sustaining, Development and Operations OM&A in 2013 and 2014 appropriate, including consideration of factors such as system reliability and asset condition?

Interrogatory

(Ex. C2/T2/S1) Please recast Schedule 1- Comparison of OM&A Expense by Major Category to include Board approved amounts for 2009-2012.

Response

ACTUAL & OEB APPROVED OM&A EXPENSE BY MAJOR CATEGORY

Transmission OM&A ($ millions)	**2009**		**2010**		**2011**		**2012**	
	OEB Approved	**Actual**	**OEB Approved**	**Actual**	**OEB Approved**	**Actual**	**OEB Approved**	**Bridge**
Sustaining								
Transmission Stations								
Land Assessment and Remediation	1.5	2.0	1.4	1.7	1.1	1.5	1.1	1.0
Environment Management	4.1	5.7	9.8	13.5	14.0	15.2	15.4	13.7
Power Equipment	69.7	67.9	66.6	59.4	66.3	68.1	66.6	54.2
Ancillary System Maintenance	13.2	12.4	16.7	10.0	15.6	11.2	16.5	10.4
Protection, Control, Monitoring, Metering and Telecommunications	37.6	38.6	42.7	40.6	43.8	43.9	45.8	48.7
Site Infrastructure Maintenance	26.7	27.0	28.1	25.1	27.3	26.9	28.0	26.8
Total Transmission Stations OM&A	152.7	153.7	165.4	150.3	168.0	166.7	173.4	155.0
Transmission Lines								
Rights of Way	23.3	25.7	26.6	24.0	27.2	26.6	28.0	26.2
Overhead Lines	22.1	19.4	19.1	15.9	19.9	16.1	22.7	20.0
Underground Cables	3.3	4.4	3.5	4.0	3.8	6.6	3.9	3.6
Total Transmission Lines OM&A	48.7	49.4	49.2	43.9	50.8	49.4	54.6	49.7
Engineering & Environmental Support	10.2	12.5	10.6	10.0	10.9	12.0	11.7	9.9
Total "Sustaining"	211.5	215.6	225.1	204.2	229.7	228.2	239.7	214.6

Transmission OM&A ($ millions)	2009		2010		2011		2012	
	OEB Approved	Actual	OEB Approved	Actual	OEB Approved	Actual	OEB Approved	Bridge
Development								
Licence Amendment to Upgrade	0.0	0.0	0.0	0.0	0.0	19.2	0.0	12.5
TS's to Facilitate Renewable Generation[1]	0.0	0.0	0.0	0.0	0.0	(19.2)	0.0	(12.5)
Technical Standards and Technology	13.9	14.0	13.1	14.1	14.1	9.5	14.8	7.9
Smart Grid	0.0	0.0	0.0	1.5	4.0	3.2	4.0	3.3
Total Development OM&A	13.9	14.0	13.1	15.7	18.1	12.6	18.8	11.2
Operations								
Operations Contracts	17.1	16.6	17.5	21.0	24.5	23.3	25.6	24.2
Environmental, Health and Safety	2.1	1.5	2.1	1.8	3.4	1.0	3.4	2.2
Operators	33.5	30.6	34.5	30.9	33.2	33.0	33.3	31.9
Large Customer & Generator Relations	5.0	4.3	5.2	4.5	5.3	3.7	5.5	3.6
Total "Operations"	57.8	53.0	59.3	58.1	66.6	61.0	67.9	61.8
Customer Care	1.5	1.5	1.5	1.5	1.1	1.5	1.2	1.2
Shared Services and Other Costs								
Asset Management	44.5	38.5	47.4	28.3	34.5	25.0	39.1	35.3
Common Corporate Functions & Services	74.4	71.2	76.7	74.8	79.2	72.3	81.7	83.1
Information Technology (including Cornerstone)	48.2	61.2	43.2	62.2	56.1	57.6	48.7	60.6
Cost of Sales	4.1	13.5	3.7	14.6	14.9	12.8	8.5	21.0
Other	(110.5)	(116.8)	(115.8)	(105.1)	(152.1)	(124.0)	(150.7)	(128.2)
Total Shared Services & Other Costs	60.7	67.7	55.3	74.8	32.6	43.7	27.2	71.8
Property Taxes & Rights Payments	69.7	65.2	71.8	66.5	70.8	67.5	72.2	70.7
Total Transmission OM&A	**415.0**	**417.1**	**426.2**	**420.8**	**418.8**	**414.5**	**427.1**	**431.3**

1

[1] Actual spend and corresponding reversal shown for presentation purposes.

Consumers Council of Canada (CCC) INTERROGATORY #15 List 1

Issue 5 **Are the proposed spending levels for Sustaining, Development and Operations OM&A in 2013 and 2014 appropriate, including consideration of factors such as system reliability and asset condition?**

Interrogatory

(Ex. C2/T2/S 1) Please explain what the Licence Amendment to Upgrade TS's to Facilitate Renewable Generation is and why there are no costs in 2013 and 2014 related to this item.

Response

Please see section 3.1 of Exhibit A, Tab 14, Schedule 1 for an explanation and further description. As per the Hydro One Transmission License amendment, Hydro One is not recovering these costs from rate payers and therefore these costs are not included in the revenue requirement for 2013 and 2014.

Toronto Hydro-Electric System Limited (THESL) INTERROGATORY #1 List 1

Issue 5 **Are the proposed spending levels for Sustaining, Development and Operations OM&A in 2013 and 2014 appropriate, including consideration of factors such as system reliability and asset condition?**

Interrogatory

Ref: Exhibit C1/Tab 2/Sch 2/ p41 lines 12, 13; p42 lines 2, 3; p 40 Fig 14, 15

a) Please explain why Hydro One considers its strategy of maintaining 25% of its underground transmission cable population in fair/poor condition over the next 10 years to be an appropriate long term strategy.

b) Please compare the forced outage frequency of underground transmission cables with the CEA benchmark for forced outage frequency of underground transmission cables. Please plot it onto the data of Figure 14. If the CEA benchmark is not available, please compare to another comparable benchmark for forced outage frequency of underground transmission cables. Please state the relative performance of Hydro One to the benchmark.

c) Please compare the forced outage duration of underground transmission cables with the CEA benchmark for forced outage duration of underground transmission cables. Please plot it onto the data of Figure 15. If the CEA benchmark is not available, please compare to another comparable benchmark for forced outage duration of underground transmission cables. Please state the relative performance of Hydro One to the benchmark.

Response

a) Hydro One believes its strategy in the long term management of the transmission underground cables to be appropriate. As per Exhibit C1, Tab 2, Schedule 2 page 41 Figure 16, the cable circuits currently rated as poor condition will be replaced under ISD# S62 of this application. Those cables that remain are considered to be in varying states of fair condition, and will be considered for replacement over approximately the next 10 years. Condition of the cable system is an important factor, but not the only factor considered for cable replacement. Refer to Exhibit C1, Tab 2, Schedule 2, pages 34–43 for further details on the sustainment of transmission underground cables.

b) The forced outage frequency for Hydro One cables versus CEA is shown in the table below. The presentation of cable performance below is a different basis from Figure 14 due to the event data structure in the CEA study. As can be seen from the table below, Hydro One's frequency of occurrences per 100km-yr is nearly twice that of the CEA average.

Cable Performance
Hydro One and All Canada-wide Cable Statistics from 2007 to 2011
Cable-Related

#	Voltage Class kV	Hydro One		All Canada	
		Frequency occ per 100 km.yr	Unavailability % per 100 km.yr	Frequency occ per 100 km.yr	Unavailability % per 100 km.yr
	110 - 299 (pool)	1.24	8.917	0.7	4.26

c) The underground cable unavailability for Hydro One versus CEA is shown in the table in part b) above. The presentation of cable performance above is a different basis from Figure 15 due to the event data structure in the CEA study. As can be seen from the table, Hydro One's unavailability is approximately twice that of the CEA average. However, this is primarily as a result of the outages associated with the two underground cable circuits that are being replaced during the test years of this application (refer to Exhibit D1, Tab 3, Schedule 2, Page 70, ISD# S62).

Ontario Energy Board (Board Staff) INTERROGATORY #36 List 1

Issue 6 **Are the proposed spending levels for Shared Services and Other O&M in 2013 and 2014 appropriate?**

Interrogatory

Ref: Exhibit C1/Tab4/Sch2/p 2
Hydro One attributes higher CCFS costs to 'higher Real Estate Costs for additional space in the company's work program'. Why do these real estate costs increase so significantly in 2012 (levels continuing to the test years) when the evidence shows a reduction of staff in 2011 and moderate staff growth from 2012 to 2014 (Exhibit C1-5-2/Attachment 2)?

Response

As outlined in the evidence Exhibit C1, Tab 4, Schedule 2 on page 24, the change in funding requirements in bridge year 2012 and test years 2013 and 2014 is mainly driven due to the following factors:

- The facilities infrastructure base is dominated by buildings that are at or reaching the end of their asset life cycle. Approximately 40% of administrative and service centre facilities are estimated to be more than 40 years old. The change in funding requirements in bridge year 2012 and test years 2013 and 2014 is driven due to incremental increase of space in the field as result of new facilities and building additions being put in service providing for replacement facilities due to end of life, and new and additional facilities to meet accommodation needs in terms of Company work program and operating requirements (which includes housing specialized work equipment). The examples of the facilities additions include the following new operation centre locations: Mississauga, Picton, Bolton, London, Belleville, and Orleans.

- The increase in funding requirements in bridge year 2012 and test year 2013 is also contributed by planned head office improvements, which are expected to result in additional temporary relocation space for employees during the duration of the improvements and employee office moves costs.

- The majority of facilities work program costs are fixed. The facilities work program is extensively driven by fixed-cost contractual obligations which arise primarily through relationships with external landlords (leases). Other fixed costs include utilities and costs that are represented by negotiated contracts with internal and external service providers for base level facility maintenance (for example, administrative/service centre building maintenance, janitorial and snow removal, minor repairs, building inspections and similar activities). The change in funding requirements in bridge year 2012 and test years 2013 and 2014 is partially influenced by rising facilities space costs described above.

- The funding requirements in bridge year 2012 takes into consideration corporate health and safety initiatives, which specifically include funding for Arc Flash calculations. The Facilities Arc Flash initiative identifies the energy levels of the electric circuits at Hydro One Operation Centres. The energy levels will then be labeled on these circuits as required so that those performing work on these circuits can do so wearing the necessary protective equipment.

Ontario Energy Board (Board Staff) INTERROGATORY #37 List 1

Issue 6 Are the proposed spending levels for Shared Services and Other O&M in 2013 and 2014 appropriate?

Interrogatory

Ref: Exhibit C1/Tab4/Sch2/p 2
Table 1 shows that along with higher Real Estate costs, Hydro One shows large Bridge Year increases in many categories: Finance 7.5%, General Counsel and Secretariat 17.6%, Regulatory Affairs 11.4%, Security Management 23% and Internal Audit 35%. In many cases these increased levels carry on into the test years. While the following pages of the evidence provide details of the work programs, no overall rationale is provided for the excessive increases in these programs and why such high increases are justified. Please provide further justification for the increases in these areas.

Response

In general, shared service spending is increasing in order to support the increase in the overall work program. With respect to the specific departments highlighted, costs increase by $8.9 million (13.6%) over the 2011-2014 period, while the total work program spend has increased by 17.2% . Please see Exhibit I, Tab 7, Schedule 1.04 Staff 42, Table 2, for details of this calculation.

Specific reasons for the increases include:

- Finance
  - Filled vacancies to shore up support capabilities
  - Transfer in of the HR Payroll function (note decrease in HR)
  - Transfer in of Business Planning and Program Results departments from Asset Management

- General Counsel
  - Increased work due to Green Energy Act and distributed generation to support government programs
  - Records Management project to increase integrity of information across the corporation

- Regulatory Affairs
  - Costs increase in 2012 due to the planned rate cases
  - Other Regulatory initiatives over the test period include Regional planning, System Reliability studies, Smart Grid Standards development, East/West Tie and other potential partnership initiatives.

- Security
  - Additional measures to address metal (copper) theft at locations across Ontario to increase safety of employees and the general public

- Internal Audit
  - Increased safety audits
  - Increased activity related to ISO 14001 & OHSAS 18001 certification

Ontario Energy Board (Board Staff) INTERROGATORY #38 List 1

Issue 6 **Are the proposed spending levels for Shared Services and Other O&M in 2013 and 2014 appropriate?**

Interrogatory

Ref: Exhibit C1/Tab4/Sch4/p 8
Table 4 shows that IT Development categories Enhancements and Upgrades almost double from 2012 to 2013. Why is such a steep increase required in 2013? Please explain whether or not this spending could be smoothed over a number of years? What is the urgency that drives these increases in the test years?

Response

Enhancement and upgrade costs were deferred in 2012 due to the focus on the Cornerstone Phase 4 CIS Replacement project. Enhancement costs in 2013 return to steady state levels (see 2010/2011) to deliver system changes that support business, process and reporting improvements. Upgrade costs in 2013 are higher due to the cyclical nature of application upgrades to keep them in a vendor supported state. Key upgrades in 2013 include SAP Supplier Relationship Management (SRM), SAP Supply Chain Management (SCM), Trilliant Head-end system, and the enterprise mobile platform. These upgrades are required to get the software into a vendor-supported state and/or to make the software compatible with Microsoft Windows 7.

Energy Probe (EP) INTERROGATORY #22 List 1

Issue 6 Are the proposed spending levels for Shared Services and Other O&M in 2013 and 2014 appropriate?

Interrogatory

Ref: Exhibit C1, Tab 3, Schedule 1, Page 6

This page discusses variances between Board Approved 2012 OM&A expenditures and 2012 projected actuals. The Shared Services and other Costs category in Table 3 shows a variance of $44.6 M.

a) Line 14 refers to an increase in Cost of Sales for a metering project planned for 2012. Please describe the metering project and specify how much of the variance of $44.6 M is attributable to it.

b) Line 15 refers to a lower amount of overhead cost capitalized as another reason for the variance. Please provide a breakdown showing the amount of capital and OM&A in projected actual cost for 2012 compared to Board Approved 2012. How much of the $44.6 M variance is attributable to this cause?

Response

a) The metering project planned for 2012 represents the work to be performed by Hydro One Transmission for the upgrading of revenue meters at various sites within the province per IESO requirements.

The variance attributable to the metering project is $12.5 million.

b)

2012 Board Approved versus 2012 Projected OM&A Expenditures
Shared Services & Other Costs ($M)

OM&A Categories	Board Approved	Projected	Variance
Real Estate	28.3	30.7	2.4
Information Technology	70.1	60.6	(9.5)
Asset Management	39.1	35.3	(3.8)
Corporate Services*	53.4	52.4	(1.0)
Total Change in Shared Services	**190.8**	**179.0**	**(11.8)**
External Work Cost of Sales	8.5	21.0	12.5
Overheads Recovered	(121.1)	(112.6)	8.5
Other Corporate Costs	(10.6)	(15.6)	(5.0)
EB-2010-0002 Reduction	(19.1)	0.0	19.1
Cornerstone Savings - Unclassified	(21.4)	0.0	21.4
Net Change in Shared Services & Other Costs	**27.2**	**71.8**	**44.6**

* Corporate Services Includes Corporate Management, Finance, Corporate Communications, Corporate Security, HR, Regulatory Affairs, General Counsel & Secretariat and Internal Audit

Energy Probe (EP) INTERROGATORY #23 List 1

Issue 6 Are the proposed spending levels for Shared Services and Other O&M in 2013 and 2014 appropriate?

Interrogatory

Ref: Exhibit C1, Tab 3, Schedule 1, Page 16

Table 4 on Page 16 shows an increase in supply chain cost from 37.6 M to 45.0 M from 2009 to 2011.

a) What was the value of material and services procured for 2009 and for 2011?

b) Line 6 states that the contract with INERGI was for the "same service levels at a declining price". Please reconcile that statement with the 20% increase in costs referred to in table 4.

Response

a) The value of material and services procured were $983 million in 2009, and $1,052 million in 2011.

b) The Inergi Contract for supply chain management has been contracted for the same service levels at a declining price over the term of the contract. However, any work provided by Inergi over and above the contracted service levels and base transaction volumes results in additional costs. The 20% increase in supply chain costs relates both to Inergi costs and costs retained by Hydro One.

Supply Chain additional costs between 2009 and 2011 were due to volume increases related to growth in Hydro One's work program requirements, and increased warehousing and transportation costs related to increased material handled and shipped. In addition, Hydro One implemented its strategic sourcing program, resulting in the sourcing savings discussed in Exhibit A, Tab 15, Schedule 6, pages 9 to 11, and depicted in Exhibit D1, Tab 4, Schedule 3, page 8. Growth in Supply Chain between 2012 and 2014 reflects a projected increased cost level related to the volume and complexity of supply chain services to support the increasing work program levels, along with increased costs to transport and handle the related material.

Energy Probe (EP) INTERROGATORY #24 List 1

Issue 6 **Are the proposed spending levels for Shared Services and Other O&M in 2013 and 2014 appropriate?**

Interrogatory

Ref. Exhibit C1, Tab 3, Schedule 1, Page 2, Tables 2 and 3

a) Please provide more detail of the variation in the 2011 Shared Services amount.

b) Please provide more detail on the major variance in 2012 shared services amount.

c) Explain why Hydro One seems unable to forecast this category of OM&A with similar accuracy to other categories.

d) Why is the 2013/2014 forecast reasonable?

Response

a) Please see Exhibit I, Tab 5, Schedule 10.02 CCC9

b) Please see Exhibit I, Tab 6, Schedule 3.01 EP 22, part b)

c) Please see Exhibit I, Tab 5, Schedule 10.02 CCC9 and Exhibit I, Tab 6, Schedule 3.01 EP 22, part b) where the specific variances in both 2011 and 2012 are documented.

d) The 2013/2014 forecast is reasonable as it is based on the rigorous business planning process as described in Exhibit A, Tab 13, Schedule 1.

Energy Probe (EP) INTERROGATORY #25 List 1

Issue 6 Are the proposed spending levels for Shared Services and Other O&M in 2013 and 2014 appropriate?

Interrogatory

Ref: Exhibit A, Tab 8, Schedule 3, Page 6, Table 2 &

Exhibit C1, Tab7, Schedule 1, Tables 1 & 2

a) Please provide a Schedule that uses the data in the first reference and lists the 2011 Board approved to forecast 2014 Shared Services and shows the pricing of the common corporate services and the allocation to affiliates.

b) Reconcile to the costs and allocation in the second reference.

c) Please provide for 2013/2014 a variance report for all material cost changes and allocations from 2012 board approved.

Response

a) See schedule that uses Exhibit A, Tab 8, Schedule 3, Page 6 Table 3 and lists the 2011 Board approved to forecast 2014 shared services and shows the pricing of the common corporate services and the allocation to affiliates.

Services (in $Thousands)	**Hydro One Inc.**	**Remotes**	**Telecom**	**Brampton Networks**
General Counsel and Secretary Services (note 1)				
2011 EB-2010-0002	92	230	92	184
2012 EB-2010-0002	86	216	86	173
2012 EB-2012-0031 Bridge	87	217	87	174
2013 EB-2012-0031 Test	89	222	89	177
2014 EB-2012-0031 Test	91	226	91	181
Financial Services				
2011 EB-2010-0002	18	305	311	407
2012 EB-2010-0002	18	307	305	380
2012 EB-2012-0031 Bridge	74	260	342	390
2013 EB-2012-0031 Test	75	263	346	396
2014 EB-2012-0031 Test	77	270	356	408

Corporate Services (note 1)				
2011 EB-2010-0002	0	352	419	33
2012 EB-2010-0002	0	366	436	34
2012 EB-2012-0031 Bridge	0	267	253	26
2013 EB-2012-0031 Test	0	274	261	27
2014 EB-2012-0031 Test	0	284	267	28
Telecommunication Services				
2011 EB-2010-0002	0	134	280	0
2012 EB-2010-0002	0	155	325	0
2012 EB-2012-0031 Bridge	0	128	279	0
2013 EB-2012-0031 Test	0	118	256	0
2014 EB-2012-0031 Test	0	115	249	0
Transfer Price Charges for HONI Assets (note 2)				
2011 EB-2010-0002	0	0	0	0
2012 EB-2010-0002	0	0	0	0
2012 EB-2012-0031 Bridge	0	0	0	0
2013 EB-2012-0031 Test	0	200	500	0
2014 EB-2012-0031 Test	0	200	500	0
Other Services				
2011 EB-2010-0002	0	620	2,033	0
2012 EB-2010-0002	0	645	2,109	0
2012 EB-2012-0031 Bridge	0	375	1,031	0
2013 EB-2012-0031 Test	0	366	1,006	0
2014 EB-2012-0031 Test	0	348	957	0
CEO/President Services				
2011 EB-2010-0002	0	80	0	0
2012 EB-2010-0002	0	80	0	0
2012 EB-2012-0031 Bridge	0	80	0	0
2013 EB-2012-0031 Test	0	80	0	0
2014 EB-2012-0031 Test	0	80	0	0
Utility Operation Services				
2011 EB-2010-0002	0	1,004	0	0
2012 EB-2010-0002	0	1,004	0	0
2012 EB-2012-0031 Bridge	0	936	0	0
2013 EB-2012-0031 Test	0	929	0	0
2014 EB-2012-0031 Test	0	929	0	0
Utility Joint Services				
2011 EB-2010-0002	0	15	0	0
2012 EB-2010-0002	0	15	0	0
2012 EB-2012-0031 Bridge	0	0	0	0
2013 EB-2012-0031 Test	0	0	0	0
2014 EB-2012-0031 Test	0	0	0	0

Supply Chain Services (note 3)				
2011 EB-2010-0002	0	77	200	0
2012 EB-2010-0002	0	77	200	0
2012 EB-2012-0031 Bridge	0	77	200	0
2013 EB-2012-0031 Test	0	77	200	0
2014 EB-2012-0031 Test	0	77	200	0
Totals (note 2 and 3)				
2011 EB-2010-0002	110	2,817	3,335	624
2012 EB-2010-0002	104	2,865	3,461	587
2012 EB-2012-0031 Bridge	161	2,340	2,192	590
2013 EB-2012-0031 Test	164	2,529	2,658	600
2014 EB-2012-0031 Test	168	2,529	2,620	617

Note 1: costs were reclassifed from general counsel to corporate services in presentation of EB-2010-0002 numbers to conform with presentation in EB-2012-0031

Note 2: Transfer price charges were incorrectly presented in $M in Exhibit A-8-3. The figures have been corrected in the table above

Note 3: EB-2010-0002 Supply chain services were included in a separate service level agreement. They have been included to conform with presentation in EB-2012-0031

b) See attached tables used to prepare Exhibit C1, Tab 7, Schedule 1 Page 3, Tables 1 and 2.

TABLE A

	2013							
Description	2013 Total	Tx	Dx	Telecom	Brampton	Remotes	HOI	Reference
Corporate Management	5.3	2.7	2.3	0.1	0.1	0.1	0.1	
General Counsel and Secretary Services	*0.9*	*0.5*	*0.4*	*0.0*	*0.0*	*0.0*	*0.0*	a
President / CEO / Chairman Services	*3.5*	*1.8*	*1.6*	*0.0*	*0.0*	*0.0*	*0.0*	b
Chief Financial Office Services	*0.9*	*0.4*	*0.3*	*0.0*	*0.0*	*0.0*	*0.0*	c
Finance	34.0	19.5	13.6	0.5	0.2	0.2	0.1	
HONI Finance	*22.0*	*12.6*	*8.7*	*0.2*	*0.2*	*0.2*	*0.1*	d
Inergi - Finance	*7.8*	*4.4*	*3.2*	*0.2*	-	*0.0*	-	e
Inergi - HR	*4.3*	*2.5*	*1.7*	*0.1*	-	*0.0*	-	f
Human Resources	10.9	6.4	4.3	0.2	-	0.1	-	g
Corporate Communications	11.4	5.3	6.1	-	-	0.1	-	h
General Counsel & Secretariat	8.9	4.7	3.6	0.1	0.2	0.2	0.1	i
Regulatory Affairs	23.6	11.5	12.0	-	-	0.1	-	j
Corporate Security	3.8	1.8	2.0	0.0	0.0	0.0	-	k
Internal Audit	4.3	2.5	1.3	0.1	0.2	0.1	0.0	l
Real Estate & Facilities	62.5	31.8	30.7	-	-	0.0	-	m
CF&S Costs (as per C1-7-1)	**164.8**	**86.1**	**75.9**	**0.9**	**0.7**	**0.9**	**0.2**	
Customer Care								
Inergi - CSO	*40.9*	-	*40.8*	-	-	*0.0*	-	n
Inergi - Settlements	*4.6*	*0.2*	*4.3*	-	-	-	-	o
Total	45.4	0.2	45.2	-	-	0.0	-	
Information Technology Systems								
Inergi - ETS	*71.9*	*28.7*	*42.3*	*0.6*	-	*0.2*	-	p
Telecom Services	18.0	10.4	7.2	0.3	-	0.1	-	q
Information Technology Systems	20.3	11.5	8.6	0.1	-	0.0	0.0	r
Total	110.2	50.7	58.1	1.0	-	0.4	0.0	
Operations								
Inergi - AP	*1.4*	*0.8*	*0.5*	*0.1*	-	*0.0*	-	s
Operations	65.0	36.9	28.2	-	-	(0.0)	-	t
Total	66.5	37.7	28.6	0.1	-	0.0	-	
Strategy	62.5	35.8	26.7	-	-	-	-	u
Facilities	(52.4)	(23.6)	(28.8)	-	-	-	-	v
Donations	1.3	-	-	-	-	-	1.3	w
Total	**398.3**	**187.0**	**205.7**	**2.0**	**0.7**	**1.3**	**1.5**	

TABLE B

	2014							
Description	2014 Total	Tx	Dx	Telecom	Brampton	Remotes	HOI	Reference
Corporate Management	5.4	2.8	2.4	0.1	0.1	0.1	0.1	
General Counsel and Secretary Services	*1.0*	*0.5*	*0.4*	*0.0*	*0.0*	*0.0*	*0.0*	a1
President / CEO / Chairman Services	*3.6*	*1.8*	*1.6*	*0.0*	*0.0*	*0.0*	*0.0*	b1
Chief Financial Office Services	*0.9*	*0.4*	*0.4*	*0.0*	*0.0*	*0.0*	*0.0*	c1
Finance	34.1	19.5	13.6	0.5	0.2	0.2	0.1	
HONI Finance	*22.7*	*13.0*	*9.0*	*0.2*	*0.2*	*0.2*	*0.1*	d1
Inergi - Finance	*7.4*	*4.1*	*3.0*	*0.2*	-	*0.0*	-	e1
Inergi - HR	*4.0*	*2.4*	*1.6*	*0.1*	-	*0.0*	-	f1
Human Resources	11.1	6.5	4.4	0.2	-	0.1	-	g1
Corporate Communications	12.6	5.7	6.8	-	-	0.1	-	h1
General Counsel & Secretariat	9.1	4.8	3.7	0.1	0.2	0.2	0.1	i1
Regulatory Affairs	23.0	9.7	13.2	-	-	0.1	-	j1
Corporate Security	3.9	1.8	2.1	0.0	0.0	0.0	-	k1
Internal Audit	4.4	2.6	1.4	0.1	0.2	0.1	0.0	l1
Real Estate & Facilities	64.3	32.7	31.6	-	-	0.0	-	m1
CF&S Costs (as per C1-7-1)	**167.9**	**86.1**	**79.1**	**0.9**	**0.7**	**0.9**	**0.2**	
Customer Care								
Inergi - CSO	*39.4*	-	*39.3*	-	-	*0.0*	-	n1
Inergi - Settlements	*4.8*	*0.2*	*4.6*	-	-	-	-	o1
Total	44.2	0.2	43.9	-	-	0.0	-	
Information Technology Systems								
Inergi - ETS	*68.8*	*27.4*	*40.7*	*0.6*	-	*0.2*	-	p1
Telecom Services	17.6	10.2	7.0	0.2	-	0.1	-	q1
Information Technology Systems	20.8	11.8	8.9	0.1	-	0.0	0.0	r1
Total	107.2	49.4	56.6	0.9	-	0.4	0.0	
Operations								
Inergi - AP	*1.4*	*0.8*	*0.5*	*0.1*	-	*0.0*	-	s1
Operations	67.9	38.0	29.9	-	-	(0.0)	-	t1
Total	69.3	38.8	30.4	0.1	-	0.0	-	
Strategy	62.7	37.0	25.7	-	-	-	-	u1
Facilities	(54.0)	(24.3)	(29.7)	-	-	-	-	v1
Donations	1.3	-	-	-	-	-	1.3	w1
Total	**398.3**	**187.0**	**205.7**	**2.0**	**0.7**	**1.3**	**1.5**	

See attached tables with mapping from Table A and B.

TABLE C

Description	2013 Total	Networks	Telecom	Brampton	Remotes	Hydro One Inc.	Materials Surcharge	Reference from Table A
Fees Payable by Affiliates to Networks								
General Counsel and Secretary Services	32,482	31,906	89	177	222	89	-	i+j
Financial Services	26,276	25,196	346	396	263	75	-	d+l
Corporate Services	46,480	45,919	261	26	274	0	-	g+h+k+r
Telecommunication Services	18,040	17,666	256	-	118	-	-	q
Other Services	130,812	129,440	1,006	-	366	-	-	e+f+n+o+p+s
Total	**254,091**	**250,127**	**1,958**	**599**	**1,242**	**164**	**-**	
Fees Payable by Networks								
General Counsel and Secretary Services	930	869	9	19	23	9	-	a
President / CEO / Chairman Services	3,514	3,391	29	35	18	41	-	b
Chief Financial Office Services	863	773	23	31	9	26	-	c
Total	**5,307**	**5,034**	**61**	**85**	**51**	**76**	**-**	
Real Estate	**10,058**	**10,045**	**-**	**-**	**13**	**-**	**-**	m+v
Donations	**1,250**	**-**	**-**	**-**	**-**	**1,250**	**-**	w
Asset Strategy/Operations (Tx/Dx Only)	**127,563**	**127,563**	**-**	**-**	**-**	**-**	**-**	t+u
Total	**398,268**	**392,769**	**2,019**	**684**	**1,305**	**1,491**	**-**	

TABLE D

Description	2014 Total	Networks	Telecom	Brampton	Remotes	Hydro One Inc.	Materials Surcharge	Reference from Table B
Fees Payable by Affiliates to Networks								
General Counsel and Secretary Services	32,046	31,458	91	181	226	91	-	i1+j1
Financial Services	27,110	25,999	356	408	270	77	-	d1+l1
Corporate Services	48,492	47,931	267	27	267	0	-	g1+h1+k1+r1
Telecommunication Services	17,550	17,187	249	-	115	-	-	q1
Other Services	125,833	124,528	957	-	348	-	-	e1+f1+n1+o1+p1+s1
Total	**251,032**	**247,103**	**1,919**	**616**	**1,226**	**168**	**-**	
Fees Payable by Networks								
General Counsel and Secretary Services	953	891	10	19	24	10	-	a1
President / CEO / Chairman Services	3,564	3,438	29	36	18	42	-	b1
Chief Financial Office Services	883	791	24	32	10	27	-	c1
Total	**5,400**	**5,121**	**62**	**87**	**52**	**78**	**-**	
Real Estate	**10,276**	**10,263**	**-**	**-**	**13**	**-**	**-**	m1+v1
Donations	**1,250**	**-**	**-**	**-**	**-**	**1,250**	**-**	w1
Asset Strategy/Operations (Tx/Dx Only)	**130,675**	**130,675**	**-**	**-**	**-**	**-**	**-**	t1+u1
Total	**398,634**	**393,163**	**1,982**	**702**	**1,291**	**1,496**	**-**	

c) See below tables for variance report on cost allocations. For details on cost changes please refer to Exhibit C1, Tab 4, Schedule 2.

Description	2013 Variance from 2012 Board Approved						
	Total	Networks	Telecom	Brampton	Remotes	Hydro One Inc.	Materials Surcharge
Fees Payable by Affiliates to Networks							
General Counsel and Secretary Services	0.0%	0.3%	0.0%	0.0%	-0.3%	0.0%	0.0%
Financial Services	0.0%	0.7%	-0.1%	-0.3%	-0.4%	0.2%	0.0%
Corporate Services	0.0%	0.0%	-0.1%	0.0%	0.1%	0.0%	0.0%
Telecommunication Services	0.0%	-0.1%	0.1%	0.0%	0.0%	0.0%	0.0%
Other Services	0.0%	0.9%	-0.7%	0.0%	-0.2%	0.0%	0.0%
Total	**0.0%**	**0.5%**	**-0.4%**	**0.0%**	**-0.1%**	**0.0%**	**0.0%**
Fees Payable by Networks							
General Counsel and Secretary Services	0.0%	-0.1%	0.0%	0.0%	0.0%	0.0%	0.0%
President / CEO / Chairman Services	0.0%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%
Chief Financial Office Services	0.0%	0.6%	-0.5%	-0.5%	0.3%	0.0%	0.0%
Total	**0.0%**	**0.4%**	**-0.1%**	**-0.2%**	**0.0%**	**0.0%**	**0.0%**
Real Estate	**0.0%**	**-0.1%**	**0.0%**	**0.0%**	**0.1%**	**0.0%**	**0.0%**
Donations	**0.0%**	**0.0%**	**0.0%**	**0.0%**	**0.0%**	**0.0%**	**0.0%**
Total	**0.0%**	**1.1%**	**-0.6%**	**-0.1%**	**-0.3%**	**-0.1%**	**0.0%**

Description	2014 Variance from 2012 Board Approved						
	Total	Networks	Telecom	Brampton	Remotes	Hydro One Inc.	Materials Surcharge
Fees Payable by Affiliates to Networks							
General Counsel and Secretary Services	0.0%	0.3%	0.0%	0.0%	-0.3%	0.0%	0.0%
Financial Services	0.0%	0.7%	-0.1%	-0.3%	-0.5%	0.2%	0.0%
Corporate Services	0.0%	0.0%	-0.1%	0.0%	0.1%	0.0%	0.0%
Telecommunication Services	0.0%	-0.1%	0.1%	0.0%	0.0%	0.0%	0.0%
Other Services	0.0%	0.9%	-0.7%	0.0%	-0.2%	0.0%	0.0%
Total	**0.0%**	**0.5%**	**-0.4%**	**0.0%**	**-0.1%**	**0.0%**	**0.0%**
Fees Payable by Networks							
General Counsel and Secretary Services	0.0%	-0.1%	0.0%	0.0%	0.0%	0.0%	0.0%
President / CEO / Chairman Services	0.0%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%
Chief Financial Office Services	0.0%	0.6%	-0.5%	-0.5%	0.3%	0.0%	0.0%
Total	**0.0%**	**0.3%**	**-0.1%**	**-0.2%**	**0.0%**	**0.0%**	**0.0%**
Real Estate	**0.0%**	**-0.1%**	**0.0%**	**0.0%**	**0.1%**	**0.0%**	**0.0%**
Donations	**0.0%**	**0.0%**	**0.0%**	**0.0%**	**0.0%**	**0.0%**	**0.0%**
Total	**0.0%**	**1.1%**	**-0.6%**	**-0.1%**	**-0.3%**	**-0.1%**	**0.0%**

There are no variances greater than 1% in the 2013/2014 cost allocations compared to the 2012 allocations.

Activities in Financial Services that cause shifts from Remotes and Brampton to Networks include Internal Control & Bill 198 activities with a partial offset in time spent on External Reporting and External Audits. Also activities based on the physical driver of assets such as taxation shifted towards Networks as the asset base of Networks grew in higher proportion than Remotes.

Activities in Other Services, which consists of primarily Inergi costs have also shifted towards Networks. Inergi Finance costs which uses a blend of physical drivers including revenues and total assets has more cost weighted towards Networks than Telecom and Remotes.

Energy Probe (EP) INTERROGATORY #26 List 1

Issue 6 Are the proposed spending levels for Shared Services and Other O&M in 2013 and 2014 appropriate?

Interrogatory

Refs. Exhibit C1, Tab 4, Schedule 2, Page 2, Table 1 &
Exhibit C1, Tab 4, Schedule 2, Page 24 - 1.9 Real Estate and Facilities

a) Please provide a version of Table 1 that shows the Board-approved 2012 amounts by category.

b) For 2012 Finance cost increase, please identify the reduction in Inergi fees and provide the net amount saved by ratepayers due to bringing the functions in-house.

c) Please provide more details of the real estate related cost increase in 2012 continuing into 2013
   i) In house services costs
   ii) External contract services costs
   iii) Rents/leases
   iv) Amounts capitalized
   v) Other material costs

d) Please provide annual office/workspace costs owned and leased 2009-2014.

e) Please provide office/workspace costs per employee (FTE) 2009-2014.

Response

a)

Table 1

Total 2009 - 2014 CCF&S Costs and 2013/2014 Allocation to Transmission ($ Millions)

Description	Historic			Bridge	Test		TX Board Approved	TX Allocation	
	2009	2010	2011	2012	2013	2014	2012	2013	2014
Corporate Management	6.0	5.0	5.1	5.2	5.3	5.4	2.7	2.7	2.8
Finance	30.7	31.4	31.9	34.3	34.0	34.0	14.4	19.5	19.5
Human Resources	15.6	16.4	11.0	10.9	10.9	11.2	10.0	6.4	6.5
Corporate Communications*	8.9	9.6	8.7	9.1	11.4	12.6	5.2	5.3	5.7
General Counsel and Secretariat	6.6	7.5	7.4	8.7	8.9	9.1	4.5	4.7	4.8
Regulatory Affairs	19.5	21.3	20.1	22.4	23.6	23.0	13.3	11.5	9.7
Security Mgmt.	2.1	2.4	3.0	3.7	3.8	3.9	1.3	1.8	1.8
Internal Audit	2.7	2.8	3.1	4.2	4.3	4.4	1.9	2.5	2.6
Real Estate & Facilities	50.6	49.9	51.6	60.2	62.5	64.3	28.3	31.8	32.7
Total Cost	**142.7**	**146.3**	**141.9**	**158.7**	**164.8**	**167.9**	**81.7**	**86.1**	**86.1**

** Corporate Communications re-stated to exclude certain costs associated with VP Corporate Relations & Regulatory Affairs which are now included in Operations Exhibit C1-3-4 and the work associated with External relations and portion of the Corporate Communications group which can now be found in Shared Services Asset Management C1-4-3.*

b) Total Year over Year Savings arising from the Inergi contract in Finance (including the transferred-in payroll function) are $0.7M in 2012, $0.7M in 2013 and $0.8M in 2014.

No Inergi Finance functions were brought in-house to Hydro One.

c)

	Bridge $M	**Test $M**	
	2012	**2013**	**2014**
In House Service Costs	6.6	7.3	7.5
Contracted Services	13.7	13.9	14.6
Leased Facilities	26.3	26.8	27.2
Utilities	3.8	4.4	4.7
Total Costs	**50.4**	**52.4**	**54.0**

Please see Exhibit I, Tab 6, Schedule 1.01 Staff 36 for more details.

d)

	Historic			**Bridge**	**Test**	
in $M	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**
Leased Facilities	22.4	22.7	23.9	26.3	26.8	27.2
Owned Facilities	20.3	18.6	19.4	24.1	25.6	26.8
Total Costs	**42.7**	**41.3**	**43.3**	**50.4**	**52.4**	**54.0**

e) The facilities work program provides for workspace for employees, storage and garage facilities for work equipment. The workspace requirements include space accommodation for various types of staff resources e.g. regular, temporary, contractors and consultants and can vary depending on geographic region and changing company operational requirements including size and storage of specialized equipment.

The field operation centre facilities are mainly suited to meet operational requirements and typically provide accommodation solutions not only to employees but also for operational company requirements such as specialized work equipment, fleet and storage facilities. The field facilities vary depending on geographic region and changing company operational requirements including size and storage of specialized equipment.

The office facilities within GTA, (e.g. head office), provides space accommodation for various types of staff resources (e.g. regular, temporary, contractors and consultants). The average space allocation per staff is approximately 160 sq ft (this includes shared space such as meeting and other common areas etc). The head office space consists of 285,616 sq ft and provides workspace to approximately 1,800 staff. The actual workspace cost can vary and is subjected to negotiated lease terms and associated operating costs (e.g. utilities, taxes etc). The table below summarizes the average cost per employee.

Head Office space cost (in $K)	**Historic**			**Bridge**	**Test**	**Test**
	2009	**2010**	**2011**	**2012**	**2013**	**2014**
Cost per Employee	4.7	5.2	5.1	5.3	5.4	5.5

Vulnerable Energy Consumers Coalition (VECC)INTERROGATORY #30 List 1

Issue 6 **Are the proposed spending levels for Shared Services and Other O&M in 2013 and 2014 appropriate?**

Interrogatory

Reference: Exhibit C1, Tab 3, Schedule 1, page 2, Table 1

a) Please explain why the 2013 forecast for Shared Services and Other OM&A has increased from $68.0M in the pre-filed evidence to $69.5M in the updated evidence.

Response

The increase in the updated evidence is due to an increase in the OEB/NEB Costs section, to cover the anticipated allocated proceeding costs from the OEB for the East West Tie designation process (EB-2012-0180 and EB-2011-0140).

Vulnerable Energy Consumers Coalition (VECC)INTERROGATORY #31 List 1

Issue 6 Are the proposed spending levels for Shared Services and Other O&M in 2013 and 2014 appropriate?

Interrogatory

Reference: Exhibit C1, Tab 3, Schedule 1, pages 5 and 6, Tables 2 and 3

Preamble: It appears that in order for Hydro One to keep its overall OM &A expenditures close to the Board approved amounts in 2011 and in 2012, Hydro One has reduced spending in aggregate on other categories of OM&A in order to accommodate very large increases in Shared Services and Other Costs above Board approved figures: in Shared Services and Other Costs, Hydro One overspent the Board approved amount by $11.1M or 34.0% in 2011 and by $44.6M or 164.0% in 2012.

a) In any given year (or two years), does Hydro One view spending on Sustaining, Development, and Operations OM&A as spending that can be easily and materially adjusted to keep the overall OM&A spending within its approved envelope?

b) Please provide a table that breaks down the overspending (i.e., above Board approved) on Shared Services and Other Costs by component for 2011 and 2012.

c) Please provide a table that shows, for 2011 and 2012, a breakdown of the variances below Board approved amounts, in OM&A spending for Sustaining, Development, and Operations OM&A, indicating which projects, initiatives, routine spending amounts were cut to below the Board approved figures for these two years

d) Please extend Table 2 to include a comparison of Board approved versus actual OM&A expenditures for all historic years prior to 2011.

Response

a) No, this spending cannot be easily and materially adjusted. Please see the response to Exhibit I, Tab 5, Schedule 1.01 Staff 23.

b)

Board Approved versus Projected/Actual OM&A Expenditures						
Shared Services & Other Costs						
OM&A Categories	**2011 Board Approved**	**2011 Historic**	**Variance**	**2012 Board Approved**	**2012 Bridge Year**	**Variance**
	($M)	($M)	($M)	($M)	($M)	($M)
Real Estate	27.6	26.7	-0.9	28.3	30.7	2.4
Information Technology (excl. Cornerstone)	68.6	57.6	-11.0	70.1	60.6	-9.5
Asset Management	34.5	25.0	-9.5	39.1	35.3	-3.8
Corporate Services	51.6	45.6	-6.0	53.4	52.4	-1.0
Total Change in Shared Services	**182.2**	**154.9**	**-27.4**	**190.8**	**179.0**	**-11.8**
External Work Cost of Sales	14.9	12.8	-2.2	8.5	21.0	12.5
Overheads Recovered	-126.3	-105.5	20.8	-121.1	-112.6	8.5
Other Corporate Costs	-11.9	-18.5	-6.6	-10.6	-15.6	-5.0
EB-2010-0002 Reduction*	-13.9	0.0	13.9	-19.1	0.0	19.1
Cornerstone Savings*	-12.5	0.0	12.5	-21.4	0.0	21.4
Net Change in Shared Services & Other Costs	**32.6**	**43.7**	**11.1**	**27.2**	**71.8**	**44.6**

* Adjustments made to Board Approved amounts to account for the Envelope Reduction from the Decision and the Cornerstone savings included in EB-2010-0002

c)

Board Approved versus Historic & Bridge Year OM&A Expenditures Sustainment, Development & Operating Costs						
OM&A Categories	**2011 Board Approved**	**2011 Historic**	**Variance**	**2012 Board Approved**	**2012 Bridge Year**	**Variance**
	($M)	($M)	($M)	($M)	($M)	($M)
Sustainment						
Stations	168.0	166.7	(1.3)	173.4	155.0	(18.5)
Lines	50.8	49.4	(1.4)	54.6	49.7	(4.9)
Engineering and Environmental Support	10.9	12.0	1.1	11.7	9.9	(1.8)
Total Sustainment	**229.7**	**228.2**	**(1.6)**	**239.7**	**214.6**	**(25.2)**
Development						
Smart Zone	4.0	3.2	(0.8)	4.0	3.3	(0.7)
Standards, Research, Development & Demonstration	14.1	9.5	(4.6)	14.8	7.9	(6.9)
Total Development	**18.1**	**12.6**	**(5.4)**	**18.8**	**11.2**	**(7.6)**
Operating						
Operations	33.2	33.0	(0.2)	33.3	31.9	(1.4)
Operations Support	24.5	23.3	(1.3)	25.6	24.2	(1.5)
Environment, Health, & Safety	3.4	1.0	(2.4)	3.4	2.2	(1.2)
Large Customer & Generator Relations	5.3	3.7	(1.6)	5.5	3.6	(1.9)
Total Operating	**66.6**	**61.0**	**(5.6)**	**67.9**	**61.8**	**(6.1)**

d) For details on past year variances of Board Approved versus Actuals please refer to Exhibit I, Tab 5, Schedule 10.07 CCC 14.

School Energy Coalition (SEC)INTERROGATORY #19 List 1

Issue 6 **Are the proposed spending levels for Shared Services and Other O&M in 2013 and 2014 appropriate?**

Interrogatory

Please reproduce Table 1 showing the Tx allocation for 2009-2014.

Response

Total 2009 - 2014 CCF&S Costs and Allocation to Transmission ($ Millions)

Description	Historic			Bridge	Test	
	2009	2010	2011	2012	2013	2014
Corporate Management	3.2	2.9	2.2	2.7	2.7	2.8
Finance	16.3	18.1	17.6	19.6	19.5	19.5
Human Resources	8.3	9.5	6.6	6.4	6.4	6.5
Corporate Communications*	4.7	5.6	3.8	5.2	5.3	5.7
General Counsel and Secretariat	3.5	4.3	4.2	4.6	4.7	4.8
Regulatory Affairs	10	9.8	8.9	9.8	11.5	9.7
Security Mgmt.	1.1	1.4	1.5	1.7	1.8	1.8
Internal Audit	1.5	1.6	2	2.5	2.5	2.6
Real Estate & Facilities	23.9	23.5	26.7	30.7	31.8	32.7
Total Cost	**72.5**	**76.5**	**73.4**	**83.1**	**86.1**	**86.1**

** Corporate Communications re-stated to exclude certain costs associated with VP Corporate Relations & Regulatory Affairs which are now included in Operations Exhibit C1, Tab 3, Schedule 4 and the work associated with External relations and portion of the Corporate Communications group which can now be found in Shared Services Asset Management C1, Tab 4, Schedule 3.*

Consumers Council of Canada (CCC) INTERROGATORY #16 List 1

Issue 6 Are the proposed spending levels for Shared Services and Other O&M in 2013 and 2014 appropriate?

Interrogatory

(Ex. A/T8/S3) Have there been any significant changes related either to the Services provided by HONI to its affiliates, or the Services provided by the affiliates to HONI in 2013 and 2014 relative to 2012? If so, please identify the changes and how they impact the 2013 and 2014 Revenue Requirements

Response

Commencing 2013, Hydro One Networks added Transfer Price Charges for HONI Assets to the service level agreements. The amount charged by HONI to Hydro One Remotes and Hydro One Telecom is $0.2M and $0.5M respectively in each of the test years. See updated Exhibit A, Tab 8, Schedule 3, page 7. This transfer price charge to the subsidiaries is for use of common assets owned by Hydro One Networks and reduces 2013 and 2014 Transmission rates revenue requirement by approximately $0.4M each year.

Consumers Council of Canada (CCC) INTERROGATORY #17 List 1

Issue 6 Are the proposed spending levels for Shared Services and Other O&M in 2013 and 2014 appropriate?

Interrogatory

(Ex. A/T8/S2) What is the total annual cost associated with HONI's Board of Directors? How is that cost allocated among the various HONI entities?

Response

The costs for the Hydro One Inc. Board of Directors is filed at Exhibit A, Tab 8, Schedule 3, Page 3, Table 3 and is allocated per the Service Level Agreement filed at Exhibit A, Tab 8, Schedule 3, Appendix A, Page 8, Schedule A in accordance with the Shared Services Cost Allocation Study filed at Exhibit C1, Tab 7, Schedule 1.

There are no specific costs allocated to the other entities respecting the HONI Board of Directors since each member of the Board holds an executive position within HONI, their duties on the Board of Directors are part of their overall accountability.

Consumers Council of Canada (CCC) INTERROGATORY #18 List 1

Issue 6 **Are the proposed spending levels for Shared Services and Other O&M in 2013 and 2014 appropriate?**

Interrogatory

(Ex. C1/T4/S2/p. 2) Please recast Table 1 to include Board approved amounts for 2009-2012.

Response

Board approved amounts for Transmission are included in the following table:

Description	Board Approved ($M)			
	2009	2010	2011	2012
Corporate Management	3.1	3.1	2.6	2.7
Finance	18.9	18.6	14.5	14.4
Human Resources	6.6	6.7	9.6	10
Corporate Communications	3.2	3.3	5.5	5.2
General Counsel and Secretariat	4.5	4.6	4.8	4.5
Regulatory Affairs	10.4	11.3	11.3	13.3
Security Mgmt.	1.3	1.3	1.3	1.3
Internal Audit	1.9	1.9	1.9	1.9
Real Estate & Facilities	24.5	25.8	27.6	28.3
Total Cost	74.4	76.7	79.2	81.7

Consumers Council of Canada (CCC) INTERROGATORY #19 List 1

Issue 6 **Are the proposed spending levels for Shared Services and Other O&M in 2013 and 2014 appropriate?**

Interrogatory

(Ex. C1/T4/S2/p. 2) Please explain why the Real Estate and Facilities costs increase significantly from 2012 to 2014. Please provide a detailed budget for that cost category.

Response

Please refer to Exhibit I, Tab 6, Schedule 1.01 Staff 36 and Exhibit I, Tab 6, Schedule 3.05 EP 26 for further details.

	Bridge	**Test Years**	
in $M	**2012**	**2013**	**2014**
Real Estate	9.8	10,0	10.3
Total Facilities	50.4	52.4	54.0
Field Facilities	29.0	30.2	31.5
GTA Facilities	21.4	22.2	22.5
Total Costs	**60.2**	**62.4**	**64.3**

Consumers Council of Canada (CCC) INTERROGATORY #20 List 1

Issue 6 **Are the proposed spending levels for Shared Services and Other O&M in 2013 and 2014 appropriate?**

Interrogatory

(Ex. C1/T4/S2/p. 12) Please provide Board approved numbers for the Corporate Communications function for the years 2009-2012. Please provide detailed budgets for the test years and explain why there is a significant increase in 2013 and 2014 relative to historical levels.

Response

Corporate Communications

	Transmission Board Approved				Proposed	
	2009	**2010**	**2011**	**2012**	**2013**	**2014**
Corporate Communications	1.5	1.6	1.7	1.7	2.7	2.8
First Nations & Metis Relations	0.7	0.7	2.1	2.1	1.5	1.5
Outsourcing Services	1	1	1.7	1.4	1	1.3
Total	**3.2**	**3.3**	**5.5**	**5.2**	**5.3**	**5.7**

For Hydro One Transmission, the test year spending is relatively stable from Board Approved historic year 2011. The main increases proposed in the Corporate Communications Function relate to the Corporate Communications department. There are a number of customer-focused projects that will result in the increase including the development, construction and deployment of the Hydro One Mobile Customer Experience Centre, which will travel across Ontario educating Hydro One customers and communities on electricity, conservation and safety; and expanded customer research focus groups across Ontario to ensure that communications meets their needs and reflect the information customers value.

Consumers Council of Canada (CCC) INTERROGATORY #21 List 1

Issue 6 **Are the proposed spending levels for Shared Services and Other O&M in 2013 and 2014 appropriate?**

Interrogatory

(Ex. C1/T4/S2/p. 18) Please provide a detailed budget for the Regulatory Affairs Function for the years 2012-2014.

Response

Regulatory Affairs Function			
	Proposed		
	2012	**2013**	**2014**
Regulatory Affairs	7.5	7.7	8.2
OEB Costs	11.1	13.0	11.8
NEB Costs	1.2	1.2	1.3
Rate Hearings	2.6	1.8	1.7
Total	**22.4**	**23.6**	**23.0**

Consumers Council of Canada (CCC) INTERROGATORY #22 List 1

Issue 6 **Are the proposed spending levels for Shared Services and Other O&M in 2013 and 2014 appropriate?**

Interrogatory

(Ex. C1/T4/S4/p. 8) Please provide an explanation for the significant increase in the IT OM&A Development Costs from 2012 to 2013 and 2014. Please provide the Board approved amounts for 2009-2012.

Response

Please refer to Exhibit I, Tab 6, 1.03 Staff 38 for explanation on development costs. The Board approved amounts for 2009-2012 are as follows:

Description	**Historic TX Allocation**			
	2009	**2010**	**2011**	**2012**
Small Projects / Enhancements	1.5	3.9	3.6	3.6
Upgrades	1.4	1.9	2	2
Impact of Capital Projects	0	0	0	0
Total	**2.9**	**5.8**	**5.6**	**5.6**

Ontario Energy Board (Board Staff) INTERROGATORY #39 List 1

Issue 7 **Are the 2013/14 Human Resources related costs (wages, salaries, benefits, incentive payments, labour productivity and pension costs) including employee levels appropriate? Has Hydro One demonstrated improvements in efficiency and value for dollar associated with its compensation costs?**

Interrogatory

Ref: Exhibit C1/Tab5/Sch1/pp 10&11
Hydro One mentions that it uses Temporary, Casual and Contract staff. What is the approximate percentage saving to Hydro One from using each of these staffing sources instead of regular employees?

Response

Temporary and Casual construction employees do not participate in the pension and benefit programs afforded to regular employees. As a result, the burden rates assigned to temporary and casual construction employees are less then the burden rate for regular employees. 2013 burden rates for these employee classifications are:

Regular employee: 63%
Temporary employee: 5.8%
Casual employees (Hiring Hall and Construction employees): 5.8%

Contract staff are not employees so burden rates do not apply. Unlike temporary or casual employees whose remuneration is fixed through the collective agreements, the remuneration for contract staff is determined by market rates for the required skill set as per the RFP process we use to secure these resources. Contract staff can be managed effectively since they are acquired for a specific assignment/project to supplement internal resources and/or address peak work load challenges and once completed the contract is terminated without any further liability or obligation.

Ontario Energy Board (Board Staff) INTERROGATORY #40 List 1

Issue 7 **Are the 2013/14 Human Resources related costs (wages, salaries, benefits, incentive payments, labour productivity and pension costs) including employee levels appropriate? Has Hydro One demonstrated improvements in efficiency and value for dollar associated with its compensation costs?**

Interrogatory

Ref: Exhibit C1/Tab5/Sch2/pp 2&3
With regard to the findings in the Mercer study, Hydro One indicates that, "PWU staff were found to be 18% above market median, an improvement from the 2008 result of 21% above market median reflecting the increased use of hiring hall staff and the increased pension contributions negotiated as part of the new collective agreement." Hydro One also mentions that Hiring Hall staff do not receive Hydro One benefits or join the Hydro One Pension plan.

a) How was Hiring Hall staffing accounted for in the Mercer Study?
b) Besides the lack of benefits and the pension plan, are there any other savings realized by using Hiring Hall staff?
c) Are there any restrictions or limits on how extensively Hydro One can use the Hiring Hall?
d) What is the percentage of work currently performed by Hiring Hall staff?
e) What is the approximate percentage saving to Hydro One from using Hiring Hall rather than regular staff?

Response

As a point of clarification, the examples of increased use of the hiring hall and increased pension contributions are two separate examples.

a) The following hiring hall classifications were included in the Mercer Study:
   - Lines apprentice
   - Electrical apprentice
   - Lineman – Journeyman
   - General Labourer

b) Yes, there are other savings realized by using hiring hall staff other than no pension and benefits costs. These include:
   - No sick leave or vacation entitlement
   - No notice or severance entitlements upon termination
   - Greater flexibility in adjusting to work load changes

- Some lower rated classifications
- Province wide ability to mobilize employees

c) Contractually, hiring hall resources are used as supplemental resources over and above core work requirements. As such, Hydro One is restricted from replacing regular staff with hiring hall employees and /or using hiring hall staff for on-going /core work requirements.

d) During peak periods, hiring hall staff could be as high as approximately 30% of the regular workforce.

e) Please refer to Exhibit I, Tab 7, Schedule 1.01 Staff 39.

Ontario Energy Board (Board Staff) INTERROGATORY #41 List 1

Issue 7 **Are the 2013/14 Human Resources related costs (wages, salaries, benefits, incentive payments, labour productivity and pension costs) including employee levels appropriate? Has Hydro One demonstrated improvements in efficiency and value for dollar associated with its compensation costs?**

Interrogatory

Ref: Exhibit C1/Tab5/Sch2/p 6
Hydro One indicates that it, "…sought to achieve overall cost reductions by negotiating increased management flexibility to run the operations as opposed to wide scale reductions in wages benefits and pensions." Please provide some examples of the increased management flexibility achieved and how this will save or reduce resources required.

Response

The evidence is making the point that rather than risking the supply of reliable electricity by engaging in a protracted labour disruption with the PWU, Hydro One has made gains in reducing costs by negotiating increased flexibility. This is not to say that across the board wage, benefit and pension reductions have not been achieved. Examples of broader cost reductions are the elimination of the PWU Incentive Plan and the recent increase in PWU employee pension contributions.

Examples of increased management flexibility achieved through PWU negotiation include:

- Blanket ability to contract out specific work ie. Janitorial, snow removal, heavy equipment, rock drilling, office moves, minor fleet maintenance, minor office modifications. Savings would include the ability to perform work at a lower cost and/or avoid investing in specialized equipment
- Adding afternoon shift for fleet operations and central maintenance shop. This will eliminate requirement to pay overtime for work performed during the afternoon shift.
- Increase usage of the hiring hall by adding new classifications to the hiring hall. This allows Hydro One to utilize a flexible workforce without pension and benefit costs.
- Adding new lower rated classifications. This allows for work to be performed at a lower rate than otherwise possible.

Ontario Energy Board (Board Staff) INTERROGATORY #42 List 1

Issue 7 **Are the 2013/14 Human Resources related costs (wages, salaries, benefits, incentive payments, labour productivity and pension costs) including employee levels appropriate? Has Hydro One demonstrated improvements in efficiency and value for dollar associated with its compensation costs?**

Interrogatory

Ref: Exhibit C1/Tab5/Sch2/p 7
Hydro One indicates that its, "…work program is expected to increase by approximately 15.8% while the regular headcount is only expected to increase from year 2011 by 1.9% by year end 2014."
a) Please provide the background numbers used to make these calculations.
b) Please provide a similar calculation using total staffing numbers, not just regular staff.

Response

a) The initial calculation used to derive the growth in work program of 15.8% is shown in Table 1 below. With the August 15 update to evidence, this growth is now calculated to be 17.2%. The underlying calculations for the update are shown in Table 2 below.

Table 1

($M)	2011	2014
Tx OM&A	$ 433.7	$ 459.8
Tx CapEx	$ 810.2	$ 1,088.5
Dx OM&A	$ 554.4	$ 569.4
Dx CapEx	$ 595.7	$ 655.1
Total	$ 2,394.0	$ 2,772.8
2011 to 2014 Change ($)		$ 378.8
2011 to 2014 Change (%)		15.8%

Table 2

($M)	2011	2014
Tx OM&A*	$ 433.7	$ 459.8
Tx CapEx	$ 810.2	$ 1,121.5
Dx OM&A	$ 554.4	$ 569.4
Dx CapEx	$ 595.7	$ 655.1
Total	$ 2,394.0	$ 2,805.8
2011 to 2014 Change ($)		$ 411.8
2011 to 2014 Change (%)		17.2%

b) The calculations used to derive the growth in headcount are provided in Table 3 below.

Table 3

	2011	2014
REPRESENTATION	**TOTAL NO. EMPLOYEES**	**TOTAL NO. EMPLOYEES**
PWU Reg	3456	3511
SOCIETY Reg	1330	1371
MCP Reg	644	655
Total Regular Employees	**5,430**	**5,537**
2011 to 2014 change (No.)		107
2011 to 2014 change (%)		2.0%
PWU Temp	211	281
Society Temp	79	105
MCP Temp	22	29
Total Temp Employees	**312**	**415**
Total Casual Employees	1,488	1,617
TOTAL number of Employees at Year End	**7,230**	**7,570**
2011 to 2014 change (No.)		340
2011 to 2014 change (%)		4.7%

Total headcount will increase by 4.7% over period 2011 to 2014. However, this is based on year end headcount. Temporary and casual staff head count is typically lower than at peak periods so this percentage will be lower than actual total headcount during peak periods.

Ontario Energy Board (Board Staff) INTERROGATORY #43 List 1

Issue 7 **Are the 2013/14 Human Resources related costs (wages, salaries, benefits, incentive payments, labour productivity and pension costs) including employee levels appropriate? Has Hydro One demonstrated improvements in efficiency and value for dollar associated with its compensation costs?**

Interrogatory

Ref: Exhibit C1-5-2/Attachment 2
These tables show numbers of total employees by category from 2009 to 2014. In 2009 Regular Employees make up 71.3% of the total, Temporary Employees 4.7% of the total and Casual Employees 24%. In 2014 the percentages are: Regular Employees make up 73.1%, Temporary Employees 5.5% of the total and Casual Employees 21.4%. Why does Hydro One move to a less intensive reliance on Casual Employees in the test years?

Response

Hydro One will not be relying less on casual trade employees. The comparison above is based on headcount at year end. To compare casual trade headcount on this basis is misleading since a large number of casual trade employees are laid off in December. A better comparison would be casual trade employee headcount during the peak construction/maintenance period. Table 1 demonstrates that actual casual headcount in 2012 is generally higher than 2011. Hydro One anticipates this trend will continue in 2013 and 2014.

Table 1
Casual Trade Headcount Change 2011 and 2012

	March	**April**	**May**	**June**	**July**
2011	2072	2302	2464	2518	2551
2012	2146	2415	2500	2524	2518
Change (number)	74	113	36	6	-33
Change (%)	3.6%	4.9%	1.5%	0.2%	-1.3%

Ontario Energy Board (Board Staff) INTERROGATORY #44 List 1

Issue 7 **Are the 2013/14 Human Resources related costs (wages, salaries, benefits, incentive payments, labour productivity and pension costs) including employee levels appropriate? Has Hydro One demonstrated improvements in efficiency and value for dollar associated with its compensation costs?**

Interrogatory

Ref: Exhibit C1/Tab 5/Sch3/p 4
Hydro One reports a pension plan performance of 5.3% annualized return from 2001 to 2011, above the benchmark of 5.12%. Is Hydro One satisfied with this performance? In EB-2010-0002 Hydro One reported that the pension fund was ranked in the 61st percentile since inception. What is the current percentile ranking for the fund?

Response

The Hydro One Pension Fund's (the "Fund") annualized return from 2001 to 2011 (for the period end December 31) was 5.38%, a performance that placed the Fund in the 52nd percentile. The Fund's 1 year return for the period end December 31, 2011 was 2.19% and ranks in the 61st percentile. The Fund's return for the 1 year period end August 31, 2012 was 7.38% and ranks in the 60th percentile for this period.

Hydro One is satisfied with the Fund's performance. This view is based on the market returns over the period (including the challenging market environment of 2008 and the ensuing market volatility in 2009 and 2010), as well as Hydro One's objective of ensuring an appropriate asset mix, diversification, and managing for risk to meet its long-term objectives. Hydro One proactively manages the Fund to ensure that it meets its long-term investment objectives (to be fully funded on average over the long-term, maintain stable levels of contributions and protect capital during down markets).

It is important to note that the asset mix of the Fund is the primary determinant of the Fund's returns. At Hydro One, the asset mix of the Fund is approved by the Board of Directors, and is based on a comprehensive asset liability study which takes into consideration Fund objectives, risk tolerance, diversification, costs and efficiencies. The asset mix is considered to be a long-term decision. This process considers the asset mix of other pension plans but this is not a fundamental decision making criterion due to the fact that other pension plans may have different objectives and risk tolerances resulting in different asset mixes. Hence, pension fund ranking is not and should not be a return objective of the Fund. The fact that over the longer term the Fund's rank is close to the median suggests that we are not making asset mix decisions that are significantly and materially different than the average pension plan in Canada. Over the shorter term, trying to be consistently in the top quartile would necessitate that the asset mix of the Fund be managed on a tactical basis relative to other pension plans which is an unreasonable and unachievable objective.

We emphasize that the Fund's return objective is to achieve a long-term return of the average discount rate used by the Plan's actuary to determine the going concern liability. This is an important objective since over the long-term the going-concern discount rate approximates the required return to keep pace with the change in liabilities and the cost of the benefits. The average going-concern discount rate used by the Fund's actuary over the period 2001-2011 is approximately 5.8%. The Fund's longer term return is on target and within a reasonable margin of meeting this objective.

Ontario Energy Board (Board Staff) INTERROGATORY #45 List 1

Issue 7 **Are the 2013/14 Human Resources related costs (wages, salaries, benefits, incentive payments, labour productivity and pension costs) including employee levels appropriate? Has Hydro One demonstrated improvements in efficiency and value for dollar associated with its compensation costs?**

Interrogatory

Ref: Exhibit C1/Tab 5/Sch3
As per Exhibit C1/Tab 5/Schedule 3, Hydro One is proposing to recover pension costs in the 2013 and 2014 test years on a cash basis.

a) Has Hydro One explored switching to the accrual basis to account for pension costs for financial reporting purposes and for regulatory purposes? Please provide any supporting documentation or memorandum that analyses a switch by Hydro One to the accrual basis.

b) What would the pension costs for the 2013 and 2014 test years amount to under the accrual basis of accounting? Please provide supporting documentation, including underlying assumptions.

c) Please confirm that the cash basis is more volatile compared to the accrual basis under both positive and negative asset and liability shocks. Please provide supporting documentation. If this is not the case, please explain.

d) Please confirm that the cash basis will produce lower costs than the accrual basis when market conditions or discount rates are favourable because gains on a cash basis can be realized immediately through contribution holidays. However gains on an accrual basis are amortized over the expected average service life. If this is not the case, please explain.

e) Please confirm that the cash basis will produce higher costs than the accrual basis when market conditions or discount rates are not favourable because losses on a cash basis are amortized over a small time period. However, losses on an accrual basis are amortized over the expected average service life. If this is not the case, please explain.

f) Please provide Hydro One's justification for using the cash method versus the accrual method for pension costs.

g) Please provide any documentation from Hydro One's external auditor regarding the choice of the cash method versus the accrual method – particularly the external auditor agreeing or disagreeing with Hydro One's choice of the cash method for pension costs.

h) Please list the relevant section of the USGAAP accounting standards that permits the use of the cash method for pension costs for financial reporting purposes.

Response

a) Hydro One has not explored switching to the accrual basis to account for pension costs for financial reporting and for regulatory purposes.

b) The pension costs for 2013 and 2014 under the accrual method are projected to be approximately $194 million and $182 million, respectively, which is significantly higher than under the cash basis of $154 million and $158 million, respectively. The projected estimates are based on the same data, assumptions, methods, and plan provisions used to prepare the December 31, 2011 year-ended disclosures for the Plan as disclosed in Note 12 to Hydro One's consolidated financial statements. The key assumptions used to project the costs are as follows:

   i) Accounting discount rate of 5.25% per annum.
   ii) Pension fund returns will equal 6.25% per year (net of expenses) over the projection period.

   Supporting calculations are as follows:

	2013	2014
Current Service Costs	$98	$100
Interest Cost	$292	$299
Expected Return on Plan Assets	($300)	($312)
Amortization of Past Service Cost	$2	$2
Amortization of Net Loss	$102	$93
Total	$194	$182

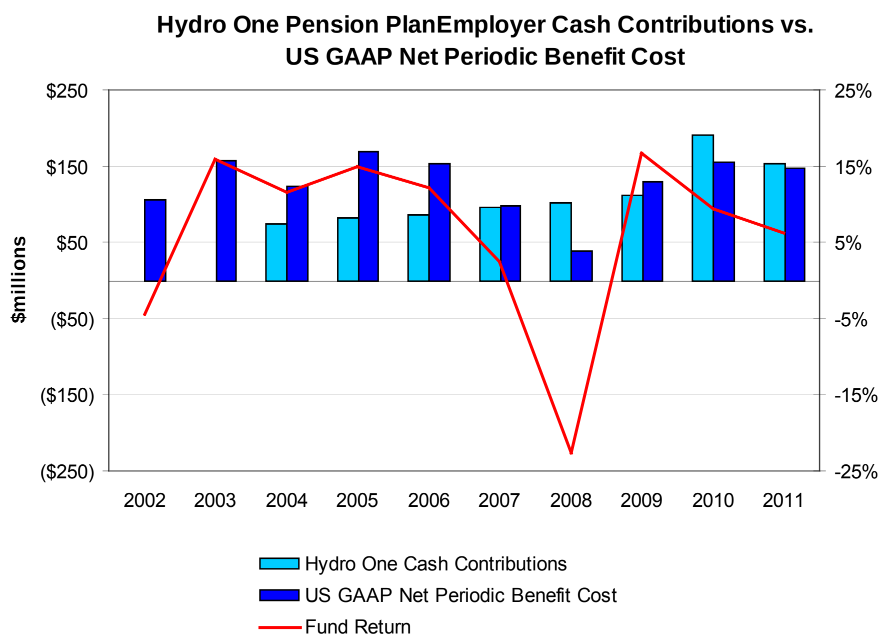
c) The following chart compares Hydro One's actual cash contributions made from 2002 to 2011 and the Net Periodic Benefit Costs (accrual basis) that Hydro One would have recorded under US GAAP accounting if US GAAP accounting had been used over this historical illustration period. The retroactive application of US GAAP was based on a number of key assumptions:

   i) The initial balance sheet position of the plan as at January 1, 2000 was the funded status of the plan on that date.

   ii) The reconciliation of plan assets and obligations under US GAAP from January 1, 2000 to December 31, 2011 is the same as the assets and obligations reported under Canadian GAAP.

iii) The accounting policies under retroactive US GAAP were assumed to be the same as they had been under Canadian GAAP. In particular, we assumed that the 10% corridor for amortization of net actuarial gains and losses would not have been applied under US GAAP, and we assumed that any one-time special adjustments that were made to the balance sheet under Canadian GAAP would have also been made under US GAAP.

This chart includes the additional contribution of $48 million that Hydro One chose to make in 2010 that was in excess of the minimum contribution required under pension legislation.



Cash basis would not have been more volatile than accrual basis under the Plan over the past 10 years as demonstrated in the above table. There are elements of the going concern valuation which mitigate the volatility of cash funding requirements. These include:

i) The smoothing of assets for going concern valuation purposes. Equity experience (returns) is smoothed over five years rather than recognized immediately by using a market value of assets as is the case for accounting costs.

ii) The going concern funding valuation discount rate is based on a long-term outlook for future Fund returns, taking into account market conditions at the time and reasonable expectations for future economic growth. By contrast, the accounting discount rate is set solely with reference to market yields on Canadian AA corporate bonds and is more responsive to movements in bond yields.

iii) The impacts of both asset and going concern liability shocks are amortized over 15 years. For accounting purposes, gains and/or losses are amortized over expected average service life (EARSL) of 11 years.

Cash contributions can be more volatile if a company is required to fund a solvency deficit in addition to a going-concern deficit as solvency deficits must be funded over a five year period under Ontario funding rules. However, Hydro One has not historically been required to fund a solvency deficit.

Hydro One's experience over the past decade may not necessarily be indicative of future experience. The relative volatility between cash basis and accrual basis may change significantly if Hydro One is subject to solvency funding requirements in the future. Nonetheless, Hydro One's historical experience may provide a useful illustration for understanding the implications of volatile markets on the cash and accounting basis. These same statements can be extended to our responses directly below.

d) It is true that experience gains can be used to reduce cash funding requirements and in certain circumstances, reduce them to zero. For accounting purposes, it is also true that experience gains would be amortized over EARSL. However, in certain circumstances (such as for pension plans with a large surplus), it is possible to produce a negative pension expense (or income). The smoothing of investment gains may also lead to delays before favourable market conditions are reflected in the contribution requirements. As such, it cannot unequivocally be said that cash basis will always be lower than accrual basis when market conditions and/or discount rates are favourable.

e) Cash basis will not necessarily be higher than accrual basis under the Hydro One Plan when market conditions and/or discount rates are not favourable. Because Hydro One's cash funding requirements are currently driven by its going concern valuation results and not solvency valuation results, the amortization period for funding experience losses is in fact longer than the current EARSL. The impacts of both asset and going concern liability shocks are amortized over 15 years for funding purposes. For accounting purposes, gains and/or losses are amortized over EARSL (currently 11 years).

f) Hydro One uses the cash method versus the accrual method for pension costs as it believes that historical OEB rate orders requested such at a time in which the cash basis resulted in lower pension expense and thus lower electricity rates. As well, the cash basis, under a known three year actuarial funding period, allows for less volatility in the short-term.

g) Hydro One's external auditor agrees with the accounting policies chosen by the company as set out in (Exhibit A, Tab 9, Schedule 1, Attachment 3) the Independent

Auditors' Report ("Report"). The Report states that they "…have audited the accompanying financial statements of the Transmission Business (a business of Hydro One Networks Inc.), which comprises…notes, comprising a summary of significant accounting policies…" and that "in our (their) opinion, the financial statements present fairly, in all material respects…in accordance with basis of accounting as set out in Note 2 to these financial statements." In Note 2 for Employee Future Benefits of our financial statements we state "In accordance with the OEB's rate orders, pension costs are recorded when employer contributions are paid to the pension fund…" also known as the cash method.

h) The source of USGAAP is the Accounting Standards Codification (ASC). ASC 980 Regulated Operations permits the use of an accounting methodology as established by a regulator for its basis of accounting for financial reporting purposes.

Ontario Energy Board (Board Staff) INTERROGATORY #45 List 1

Issue 7 **Are the 2013/14 Human Resources related costs (wages, salaries, benefits, incentive payments, labour productivity and pension costs) including employee levels appropriate? Has Hydro One demonstrated improvements in efficiency and value for dollar associated with its compensation costs?**

Interrogatory

Ref: Exhibit A/Tab10/Sch2/Attachment 2 and EB-2011-0268 Response to Board Staff Interrogatory #22

As per Exhibit A/Tab10/Schedule2/Attachment 2, Hydro One included the Hydro One Inc. Management's Discussion and Analysis ("MD&A") and Consolidated Financial Statements as at June 30, 2012.

As per page 29 of the quarterly financial statements, Hydro One describes the use of a regulatory asset for financial reporting purposes to record the net underfunded projected benefit obligation for pension and other post-employment benefits ("OPEB"). In the absence of regulatory accounting, Hydro One states that this amount would be recognized in accumulated other comprehensive income ("AOCI").

As per page 41 of the quarterly financial statements, Hydro One states that a portion of actuarial gains and losses and prior service costs and credits is recorded within regulatory assets for financial reporting purposes. In the absence of regulatory accounting, Hydro One states that this amount would be recognized in other comprehensive income ("OCI").

As per page 54 of the quarterly financial statements, Hydro One lists the following balances under USGAAP:

As at January 1, 2011 and December 31, 2011, the effect on the Consolidated Balance Sheets is reflected by the following increases (decreases): *(Canadian dollars in millions)*

	January 1, 2011	December 31, 2011
Deferred pension asset	(460)	(466)
Regulatory assets [1]	450	902
Other long-term liabilities:		
Pension benefit liability	297	779
Post-retirement and post-employment benefit liability	153	123
Regulatory liabilities [2]	(460)	(466)

[1] Represents off-setting regulatory assets for incremental obligation for pension and non-pension obligations of $297 million and $153 million on January 1, 2011, and $779 million and $123 million on December 31, 2011, respectively.

[2] Represents write-off of deferred pension asset regulatory liability under Canadian GAAP.

a) Please provide an explanation and reconcile the different numbers relating to regulatory assets and liabilities for pension and OPEB, as recognized for financial reporting purposes, on pages 29, 41, and 54 of the June 30, 2012 Hydro One Inc. quarterly financial statements.

b) Please provide an explanation of footnotes 1 and 2 on page 54 of the quarterly financial statement, as quoted above.

c) Does Hydro One plan to recover and refund in rates the regulatory assets and liabilities for pensions and OPEB that are recognized for financial reporting purposes, ie the $902 million regulatory asset and the $466 million regulatory liability recognized as at December 31, 2011 under USGAAP?

i. If so, how and when? Please explain.

ii. If so, please explain in light of Hydro One’s response to Board Staff Interrogatory #22 in EB-2011-0268. Hydro One stated that they would not record any component of the $460 million Deferred Pension Asset in the “Pension Cost Differential Account” or the “Impact for USGAAP Account.” In part e) of the response Hydro One stated that they would not attempt to recover any portion of the Deferred Pension Asset because “Both Hydro One Networks’ Distribution and Transmission businesses recover their pension costs on a cash basis.”

iii If so, please explain if and how a proposed recovery or refund of the regulatory asset and regulatory liability listed in part iii) above would change if Hydro One switched to accounting for pension costs on the accrual basis for regulatory purposes.

iv If not, please explain.

Response

a) On Page 29 of its June 30, 2012 quarterly consolidated financial report, Hydro One discussed its accounting policy for the recognition of pension, post-retirement (OPRB) and post-employment (OPEB) obligations on transition to US GAAP. Under US GAAP, the Company is required to recognize on its balance sheet the funded status of pension and non-pension benefit plans. Previously, under legacy Canadian GAAP, the funded status of benefit plans was not reflected on the balance sheet but was instead provided through supplementary note disclosure.

Hydro One’s external independent actuary provided actuarial calculations of the Company’s benefit plans on the January 1, 2011 transition date and at year end December 31, 2011, both under US GAAP. Based on those calculations, Hydro One recognized incremental pension and non-pension (OPRB and OPEB) benefit obligations on its US GAAP balance sheets. The Company also recognized offsetting regulatory assets for the incremental pension and non-pension obligations attributable to its regulated businesses, consistent with rate regulated accounting under US GAAP.

Similar to legacy Canadian GAAP, pension expense for each of Hydro One’s rate regulated subsidiaries and businesses, including Networks’ Transmission Business, continues to be recognized on a cash basis reflecting contributions to the plan, and OPRB/OPEB expense continues to be recognized on an accrual basis under US GAAP. This aligns with the respective regulatory treatments of these plans.

On page 54, Note 17 – Transition to US GAAP, Section 7 of the June 30, 2012 quarterly consolidated financial report, Hydro One provided a tabular representation of its incremental pension and OPRB/OPEB obligations on transition to US GAAP. On January 1, 2011, Hydro One recorded an incremental pension obligation of $297 million and OPRB/OPEB obligations of $153 million to reflect the plans’ relative funded status. Offsetting regulatory assets of $450 million were also recorded. On December 31, 2011, Hydro One recorded a pension obligation of $779 million and an OPRB/OPEB obligation of $123 million to reflect the plans’ funded status, again with offsetting regulatory assets of $902 million. Consistent with the adoption of US

GAAP, the deferred pension asset and offsetting regulatory liabilities that existed under legacy CGAAP were de-recognized from the balance sheets.

On page 41, Note 9 – Retirement Benefits in the second quarter report, Hydro One disclosed the components underlying the funded status of each of its benefits plans that are recognized on the balance sheet. The components include unamortized actuarial gains and losses and unamortized past service cost. Table 1 on page 41 illustrates the changes to the funded status of these benefit plans that result from actuarial gains and losses recognized in 2011. Table 2 on page 41 illustrates the regulatory offsets to the components of the funded status as of December 31, 2011.

b) Please refer to the response in part a) above.

c)

i. Hydro One does not expect to "directly" recover or refund the regulatory assets and liabilities for pensions and OPEB that are recognized for financial reporting purposes. These regulatory amounts represent offsets to the funded status of the benefit plans recognized on the balance sheet under regulatory accounting under US GAAP. The amounts conceptually represent timing differences that are reported on the balance sheet under regulatory accounting norms. These amounts, and the deferred pension asset that existed under legacy CGAAP, differ from deferral and variance accounts that are also reported as regulatory assets. Changes in the employee benefit obligations are reflected in future rates in future periods and are subject to periodic adjustment due to actuarial valuations. Under rate regulated accounting, regulatory offsets are established for those adjustments to assets or obligations that would have been included in the calculation of net income or accumulated other comprehensive income ("AOCI") for the current period for an unregulated business.

Under US GAAP the funded status of the plans is re-measured every year end based on an actuarial calculation and the offsetting regulatory amounts are adjusted accordingly. Based on the funded status of the plans, the regulatory offset can be a regulatory liability or asset notionally representing a future reduction or increase in future rates respectively. OPRB and OPEB are unfunded plans and would therefore always have a regulatory asset offset.

The $466 million regulatory liability amount offsetting the deferred pension asset under legacy CGAAP was derecognized on transition to US GAAP because the funded status of the plans based on actuarial calculation was recognized on its balance sheet.

ii. Hydro One's previous response noting that it would not attempt to recover any portion of the Deferred Pension Asset was based on the view that this regulatory amount occurs as a result of a financial reporting treatment appropriate to a rate regulated entity. The amount does not represent a liability that would be included in future rate setting in the same way that a deferral or variance account balance would be.

iii. If Hydro One switched to accrual basis for pension costs, the funded status of benefit plans would be recognized in AOCI on transition date without any offset to regulatory assets or liabilities.

iv. N/A – Please refer to the response in i. above.

London Property Management Association (LPMA) INTERROGATORY #13 List 1

Issue 7 **Are the 2013/14 Human Resources related costs (wages, salaries, benefits, incentive payments, labour productivity and pension costs) including employee levels appropriate? Has Hydro One demonstrated improvements in efficiency and value for dollar associated with its compensation costs?**

Interrogatory

Ref: Exhibit A, Tab 13, Schedule 1

a) For each staff category (Society, PWU, MCP) please provide the impact on the revenue requirement of a 1% change in the economic increase in both 2013 and 2014. Please provide the impact in 2014 based on a cumulative impact for both 2013 and 2014.

b) What is the revenue requirement impact in each of 2013 and 2014 associated with the automatic salary progressions that will occur for each of the staff categories (Society, PWU, MCP)?

c) Please provide the revenue requirement impact in each of 2013 and 2014 associated with the incentive plan payouts.

Response

a) Please refer to Exhibit I, Tab 7, Schedule 10.01 CCC 23 for the revenue requirement impact of a 1% decrease in Society's economic increase in 2013 and 2014.

   Please refer to Exhibit I, Tab 7, Schedule 10.02 CCC 24 for the revenue requirement impact of a 1% decrease in PWU's economic increase in 2013 and 2014.

   Please refer to Exhibit I, Tab 7, Schedule 10.03 CCC 25 for the revenue requirement impact of a 1% decrease in MCP's economic increase in 2013 and 2014.

b) Automatic salary progressions for Society staff impact revenue requirement by $1.0M in 2013 and $1.0M in 2014. Automatic salary progressions for PWU staff impact revenue requirement by $0.7M in 2013 and $0.8M in 2014. MCP staff are not eligible for automatic salary progressions.

c) The revenue requirement impact associated with incentive plan payouts is $2.3M in 2013 and $2.7M in 2014.

London Property Management Association (LPMA) INTERROGATORY #14 List 1

Issue 7 **Are the 2013/14 Human Resources related costs (wages, salaries, benefits, incentive payments, labour productivity and pension costs) including employee levels appropriate? Has Hydro One demonstrated improvements in efficiency and value for dollar associated with its compensation costs?**

Interrogatory

Ref: Exhibit C1, Tab 5, Schedule 2

The Mercer compensation benchmarking survey results for 2011 indicated that Hydro One was 13% above the market median on an overall basis. Please provide an estimate for each of the test years in the total compensation costs represented by this 13% over the median.

Response

The estimate is approximately $5.4 million in 2013 and $6.1 million in 2014.

Energy Probe (EP) INTERROGATORY #27 List 1

Issue 7 **Are the 2013/14 Human Resources related costs (wages, salaries, benefits, incentive payments, labour productivity and pension costs) including employee levels appropriate? Has Hydro One demonstrated improvements in efficiency and value for dollar associated with its compensation costs?**

Interrogatory

Ref: Exhibit A, Tab 17, Schedule 1 - Productivity Initiatives

Figure 1 on Page 2 of the exhibit shows Major Productivity Initiatives undertaken by Hydro One. Consolidation is said to account for $700 M in savings.

a) LDC consolidation is shown with a savings of greater than $100 M. Is this figure net of acquisition cost?

b) How much has Hydro One spent to refurbish and/or bring up to its standards the systems acquired from LDCs? Are the savings net of those costs?

c) How were the savings quantified?

d) Are the duplicate facilities mentioned in line 10, the facilities that were once operated by the LDC that was acquired? If not, please explain what duplicate facilities were eliminated as a result of LDC acquisition.

e) What were the respective asset base values with and without the 89 LDCs acquired?

f) How did these acquisitions assist Hydro One Transmission to reduce its wholesale settlement costs as mentioned in line 12? By how much were those costs reduced?

g) How many staff were acquired from the LDCs that were purchased?

Response

a) No.

b) The acquired LDCs were fully integrated within Hydro One as were all of the costs. The savings numbers provided are aggregate savings of the acquisition program – given the integrated nature of Hydro One's work program, it is not possible to separate out the incremental costs associated with any refurbishment that may have been undertaken.

Please note, for Exhibit A, Tab 17, Schedule 1, Figure 1, the savings provided for each bubble on the diagram were shown for directional and magnitudinal purposes only. As such the savings portrayed are broad estimates based on Hydro One's knowledge of the initiative undertaken. The intent is to show that productivity is not a new concept at Hydro One rather it has been incorporated into all aspects of Hydro One's strategy for many years, as evidenced by the examples in the diagram.

c) Savings were calculated by comparing the forecast LDC cost with the incremental cost to Hydro One, less 1 year of savings as an allowance for one time integration and transition costs.

d) Duplicate facilities are buildings such as operating centres where Hydro One and the acquired LDC both had such a facility in close proximity – one of the two facilities was closed, but not necessarily the one acquired from the LDC.

e)

Distribution Net Fixed Assets Prior to Acquisition	$2,448M
Net Fixed Assets Acquired Through LDC Acquisitions	$169M

f) Please note, line 12 should read: allowed Hydro One to reduce its wholesale settlement costs. The word Transmission was added in error. The consolidation of LDCs allowed Hydro One to reduce its wholesale settlement costs as a result of reduced administrative and transactional costs. These savings are estimated to be less than $250,000.

g) 202

Energy Probe (EP) INTERROGATORY #28 List 1

Issue 7 **Are the 2013/14 Human Resources related costs (wages, salaries, benefits, incentive payments, labour productivity and pension costs) including employee levels appropriate? Has Hydro One demonstrated improvements in efficiency and value for dollar associated with its compensation costs?**

Interrogatory

Ref: Exhibit A, Tab 17, Schedule 1 - Productivity Initiatives

Figure 1 on Page 2 of the exhibit shows Major Productivity Initiatives undertaken by Hydro One. The Ontario Grid Control Centre is said to have saved over $100 M.

a) What was the total cost to build, furnish and equip the centre?
b) Are the savings net of this cost? If not, please explain why the savings should not be reduced by the cost of the OGCC.
c) What were the total staffing numbers before and after the OGCC was opened?
d) What is the current approved staff complement of the OGCC?
e) How many FTEs did the OGCC employ in 2011?

Response

a) The total cost to build, furnish and equip the Ontario Grid Control Centre was $118M.

b) No. See response to Exhibit I, Tab 7, Schedule 3.01 EP 27, Part b).

c) The total staffing numbers prior to and following the implementation of the OGCC are as follows:

Pre OGCC Project (2000)	Post OGCC Project (2006)
338	222

The comparison above reflects the decrease in staff due to the OGCC amalgamation.

d) The current approved staff complement for the OGCC (Network Operating) is 265 regular staff and 24 non-regular staff for a total complement of 289.

e) In 2011 the OGCC employed 260 regular staff and 27 non-regular (casual, temporary and temporary extended) staff for a total count of 287 total staff.

Energy Probe (EP) INTERROGATORY #29 List 1

Issue 7 **Are the 2013/14 Human Resources related costs (wages, salaries, benefits, incentive payments, labour productivity and pension costs) including employee levels appropriate? Has Hydro One demonstrated improvements in efficiency and value for dollar associated with its compensation costs?**

Interrogatory

Ref: Exhibit A, Tab 17, Schedule 1 - Productivity Initiatives

Figure 1 on Page 2 of the exhibit shows Major Productivity Initiatives undertaken by Hydro One. Computer Aided Scheduling and Dispatch is said to have saved over $1 M.

a) The savings attributed to this system are greater than $1M. How were the savings measured?

b) How much did the system cost to implement?

c) Are the savings net of the implementation cost?

d) Is the system still operational or has it been replaced by a newer system? If the latter, how much did the replacement system cost?

Response

a) The bubble related to this category in Exhibit A, Tab 17, Schedule 1, Figure 1 was presented in error. It should have been >$10 M.

   The savings are based on factors such as:

   i. Effective field assignment of work to individuals and crews
   ii. Improved field productivity through more complete work packages and reduced windshield time
   iii. An amalgamation of time and accomplishment reporting
   iv. A reduction in the time required to process timesheet errors

b) The system cost approximately $14 million to implement.

c) No.

d) Yes the system is still operational.

Energy Probe (EP) INTERROGATORY #30 List 1

Issue 7 **Are the 2013/14 Human Resources related costs (wages, salaries, benefits, incentive payments, labour productivity and pension costs) including employee levels appropriate? Has Hydro One demonstrated improvements in efficiency and value for dollar associated with its compensation costs?**

Interrogatory

Ref: Exhibit A, Tab 17, Schedule 1 - Productivity Initiatives

Figure 1 on Page 2 of the exhibit shows Major Productivity Initiatives undertaken by Hydro One. Inergi Contract. Savings are greater than $100 M according to Figure 1.

a) How were the savings measured?

b) How many FTEs were saved as a result of this outsourcing?

Response

a) For the first Inergi contract, the savings were measured by comparing the costs of performing the services internally to the prices negotiated in the Inergi contract. For the second Inergi contract, the savings were measured by comparing the pricing of the first contract to the renegotiated price in the new contract.

b) As per RP-2005-0020/EB-2005-0378, Exhibit C1, Tab 3, Schedule 1, in 2002, 913 Networks employees were transferred with the contract.

Energy Probe (EP) INTERROGATORY #31 List 1

Issue 7 **Are the 2013/14 Human Resources related costs (wages, salaries, benefits, incentive payments, labour productivity and pension costs) including employee levels appropriate? Has Hydro One demonstrated improvements in efficiency and value for dollar associated with its compensation costs?**

Interrogatory

Ref: Exhibit A, Tab 17, Schedule 1 - Productivity Initiatives

Figure 1 on Page 2 of the exhibit shows Major Productivity Initiatives undertaken by Hydro One. Cornerstone is said to have saved more than $200 M for all four phases according to Figure 1.

a) What was the total cost of implementing the Cornerstone project?
b) Are the savings net of this implementation cost?
c) What is the expected life of the cornerstone system?
d) What are the annual maintenance costs of the system?
e) How was the $400 M of expected savings referred to on page 4 line 5 calculated?

Response

a) The total costs to date plus the future forecasted costs are approximately $560M.

b) No.

c) The Cornerstone assets are depreciated over a 10 year life with plans to leverage the SAP investment for the foreseeable future.

d) SAP operational costs are included in the overall outsourced agreement (Please see Exhibit C1, Tab 4, Schedule 4, pages 3 to 8 for details).

e) As per Exhibit D1, Tab 4, Schedule 3, the Cornerstone Program is targeting to exceed $400M across the Transmission and Distribution businesses with an additional $170M directly associated with the Distribution business. Details by phase are:

- Phase 1 (both Tx and Dx) = $200M
- Phase 2 (both Tx and Dx) = $50M
- Phase 3 (both Tx and Dx) = $160M - $200M
- Phase 4 (Dx only) = $172M

Energy Probe (EP) INTERROGATORY #32 List 1

Issue 7 **Are the 2013/14 Human Resources related costs (wages, salaries, benefits, incentive payments, labour productivity and pension costs) including employee levels appropriate? Has Hydro One demonstrated improvements in efficiency and value for dollar associated with its compensation costs?**

Interrogatory

Ref: Exhibit A, Tab 17, Schedule 1 - Productivity Initiatives

Figure 1 on Page 2 of the exhibit shows Major Productivity Initiatives undertaken by Hydro One. Smart Meters savings are greater than $100 M according to Figure 1.

a) What was the total cost of implementing smart meters?

b) Are the savings net of the implementation cost?

c) How were the savings calculated and what are they attributable to?

Response

a) The project is ongoing; however the smart meter implementation costs to end of June 2012 = $600.9 Million

b) No.

c) Please see Exhibit I, Tab 7, Schedule 3.01 EP 27, Part b)

The savings are attributable to reduction in manual meter reading volumes; efficiencies in annual meter re-verification and re-sealing work programs to meet Measurement Canada requirements; efficiencies in inventory management and related field services activities due to automation of meter handling and change meter order processes. The total benefit costs were derived based on reduction/elimination of certain types of work as well as automation/business process improvements. The savings were calculated based on the expected useful life of the meter.

Energy Probe (EP) INTERROGATORY #33 List 1

Issue 7 **Are the 2013/14 Human Resources related costs (wages, salaries, benefits, incentive payments, labour productivity and pension costs) including employee levels appropriate? Has Hydro One demonstrated improvements in efficiency and value for dollar associated with its compensation costs?**

Interrogatory

Ref: Exhibit A, Tab 17, Schedule 1 - Productivity Initiatives

Figure 1 on Page 2 of the exhibit shows Major Productivity Initiatives undertaken by Hydro One. Smart Grid savings are greater than $100 M according to Figure 1.

a) What has been the total cost expended on smart grid initiatives to the end of 2011?

b) Is the savings net of those costs?

c) How were the savings calculated and what are they attributable to?

Response

a) Total smart grid related expenditures to end of 2011 = $56.4 Million

b) No

c) Please see Exhibit I, Tab 7, Schedule 3.01 EP 27, Part b).

The savings are attributable to implementation of new integrated IEC61850 standard for protection & control (P&C) equipment; leveraging of existing Advanced Metering Infrastructure (AMI) to create operational efficiencies and improve outage restoration; leverage of new technology and corresponding enrichment of available data to reduce non-technical line losses.

The benefits associated with implementation of new IEC61850 standard are anticipated to be driven by reduced labour, engineering, drafting and commissioning efforts from planned TS/DS equipment refurbishment/replacement. The benefits from integration with the AMI infrastructure are anticipated to reduce unnecessary service calls through remote interrogation/diagnosis and triangulation of fault locations. A one third reduction in non-technical losses is anticipated to occur through the leverage of the new technology/data and increased monitoring and enforcement. All benefits are estimated based on a 20 year time horizon.

Energy Probe (EP) INTERROGATORY #34 List 1

Issue 7 **Are the 2013/14 Human Resources related costs (wages, salaries, benefits, incentive payments, labour productivity and pension costs) including employee levels appropriate? Has Hydro One demonstrated improvements in efficiency and value for dollar associated with its compensation costs?**

Interrogatory

Ref: Exhibit A, Tab 17, Schedule 1 - Productivity Initiatives

Figure 1 on Page 2 of the exhibit shows Major Productivity Initiatives undertaken by Hydro One. Lines 8-9 P 1 of the exhibit suggest that the initiatives detailed in the exhibit offset compensation increases.

a) Is this meant to justify higher than average wages for employees as detailed in the Mercer report or is it intended to highlight overall compensation cost savings resulting from the better systems introduced?
b) If the former (i.e. justify higher wage rates) please explain why employees should be paid more because the company has invested in better systems for them to do their work?
c) If the latter (i.e. Lower overall compensation costs due to more efficient systems) please explain why customers should pay for the systems but employees should realize the benefits in "increased compensation" (per lines 8-9)

Response

a) The intent of this exhibit is not to justify higher than average wages nor highlight overall compensation cost savings. As stated in Section 5 of Exhibit A, Tab 17, Schedule 1, the Board in its last Transmission Decision noted that it expected Hydro One to highlight productivity gains to match its compensation increases. The intent of this Exhibit is to respond to the Board's request through identifying and explaining various activities within Hydro One that demonstrate how Hydro One's focus on productivity is used to help reduce costs of operations and benefit the Ontario ratepayer.

b) N/A

c) N/A

Energy Probe (EP) INTERROGATORY #35 List 1

Issue 7 **Are the 2013/14 Human Resources related costs (wages, salaries, benefits, incentive payments, labour productivity and pension costs) including employee levels appropriate? Has Hydro One demonstrated improvements in efficiency and value for dollar associated with its compensation costs?**

Interrogatory

Ref: Exhibit A, Tab 17, Schedule 1, Page 4 - Utility Transformation

Lines 16-18 states that Hydro One helped defray large implementation costs in connection to green energy projects by assisting in the establishment of industry standards.

a) Please describe the implementation costs that were avoided by Hydro One efforts?

b) Is Hydro One suggesting that there would have been no industry standards applicable to connection of green energy projects without its efforts?

Response

a) Section 2.3 of Exhibit A, Tab 17, Schedule 1, page 4, lines 12 and 13, provide the connection of green energy projects as an example of where Hydro One has shown leadership in an industry initiative that has a large impact on ratepayers. The same Section, lines 13 to 15, mentions the establishment of industry standards, the following lines 16 to 18 indicate that Hydro One has taken a leadership position and helped defray implementation costs. Pages 4 and 5 go on to provide examples of areas where implementation costs were influenced by Hydro One efforts. Two examples of avoided implementation costs are provided below.

With regard to the communications example the key implementation cost that would have been avoided through the use of dedicated spectrum would be either third party telecommunications charges to build dedicated wire or wireless circuits to assets in underserved rural areas or the need to procure in the secondary market, if available, dedicated spectrum at market rates for the deployment of wireless links.

With regard to the revision to the definition of the Bulk Electric System, Hydro One could have been faced with significant outlays for items such as redundant protection and communications, cyber security, performance requirements for system planning and design, monitoring along with documentation and reporting to meet mandatory reliability obligations applicable to BES assets.

b) No.

Energy Probe (EP) INTERROGATORY #36 List 1

Issue 7 **Are the 2013/14 Human Resources related costs (wages, salaries, benefits, incentive payments, labour productivity and pension costs) including employee levels appropriate? Has Hydro One demonstrated improvements in efficiency and value for dollar associated with its compensation costs?**

Interrogatory

Ref: Exhibit A, Tab 17, Schedule 1, Page 4 - Utility Transformation

Lines 20-28 describe the efforts made by Hydro One to implement communications for smart meters in primarily rural locations. Line 26 mentions communications systems able to aggregate over a million meters daily.

a) Are all of Hydro One's smart meters read daily? If not, how many customers do not have daily reads and are, therefore, not on time of use rates.

b) Does Hydro One have a project to implement daily reads for all customers currently not on daily reads? If yes, please describe the timetable for implementing the daily read system.

Response

a) No, all of Hydro One's smart readers are not read daily. As of end of August 2012, 136,335 customers are not on time of use rates.

b) Hydro One's TOU migration plan recognizes that there is currently a technology gap that prevents Hydro One from cost effectively meeting the smart meter functional specifications in delivering a smart meter solution to customers in very rural parts of Hydro One's service territory. Hydro One continues to work with the industry and vendors to accelerate development of technology enhancements that will extend the "smart meter reach" to the remaining customer base; however, this is not expected to occur in the immediate term.

Energy Probe (EP) INTERROGATORY #37 List 1

Issue 7 **Are the 2013/14 Human Resources related costs (wages, salaries, benefits, incentive payments, labour productivity and pension costs) including employee levels appropriate? Has Hydro One demonstrated improvements in efficiency and value for dollar associated with its compensation costs?**

Interrogatory

Ref: Exhibit A, Tab 17, Schedule 1, Page 11

Figure 2 on Page 11 shows a graph of "Incremental Tx Productivity vs Incremental Tx Compensation".

a) Please explain what "incremental productivity" and "incremental compensation" means and how they were computed.

b) Why do the incremental productivity and incremental compensation lines decline over the test years if productivity is supposedly improving and compensation costs are increasing?

Response

a) In Figure 2, the "Incremental Tx Productivity" represents the cumulative incremental year over year increases for all productivity initiatives as outlined in Exhibit A, Tab 17, Schedule 1, Section 4 of this Schedule. The increments are computed by taking the delta between the total savings identified for all the productivity initiatives in one year and the total savings for all productivity initiatives in the next year.

   Likewise the "Incremental Tx Compensation" shows the delta between the total Corporate Tx compensation of one year over the next.

b) The incremental Tx compensation line declines over the test years as the changes in total annual Tx compensation is becoming smaller and smaller as you compare each year with the previous year's total compensation. Similarly the incremental change in productivity, being the increase in total productivity savings, is forecast to be smaller in each year going forward. Please note that this is an incremental illustration so the absolute value in either category is actually increasing but at a slower pace than previous years.

Energy Probe (EP) INTERROGATORY #39 List 1

Issue 7 **Are the 2013/14 Human Resources related costs (wages, salaries, benefits, incentive payments, labour productivity and pension costs) including employee levels appropriate? Has Hydro One demonstrated improvements in efficiency and value for dollar associated with its compensation costs?**

Interrogatory

Ref: Exhibit A, Tab 17, Schedule 2, Page 9

Table 4 on this page shows targets for a metric defined as "% of Capital and OM&A Per Gross Fixed Asset".

a) How does the Board of directors of Hydro One determine what the target for each year should be?

b) Does the Board have a long term objective for this measure? If yes, please provide it. If not, why not?

Response

a) Using historical trends and benchmarked comparables a target range is drafted. Using the Corporate Strategy and historical results as a guide, a specific target that will drive appropriate behaviour and lead to the strategic goal is selected by the Board.

b) The long-term objective is based on the Corporate Strategy goal of achieving top-quartile unit costs against utility comparables.

Energy Probe (EP) INTERROGATORY #40 List 1

Issue 7 **Are the 2013/14 Human Resources related costs (wages, salaries, benefits, incentive payments, labour productivity and pension costs) including employee levels appropriate? Has Hydro One demonstrated improvements in efficiency and value for dollar associated with its compensation costs?**

Interrogatory

Ref. Exhibit C1, Tab 3, Schedule1 Corporate Staffing

Please provide a schedule showing total actual and forecast staff numbers for Executive Management, PWU, Society and MCP groups by year from 2009 to 2014.

Response

Regular Actual MCP, Society, PWU employees (2009 -2011) and forecasted regular employees (2012- 2014)

Year	MCP	Society	PWU	Total
2009	609	1170	3307	5086
2010	651	1315	3397	5363
2011	644	1330	3456	5430
2012	659	1371	3512	5543
2013	656	1373	3511	5540
2014	655	1371	3511	5537

Energy Probe (EP) INTERROGATORY #41 List 1

Issue 7 **Are the 2013/14 Human Resources related costs (wages, salaries, benefits, incentive payments, labour productivity and pension costs) including employee levels appropriate? Has Hydro One demonstrated improvements in efficiency and value for dollar associated with its compensation costs?**

Interrogatory

Ref. Exhibit C1, Tab 5, Schedule 2, Attachment 2

a) Please provide the regulatory filing and IRRs from EB-2010-0002 showing the total Compensation for HO 2011 in a similar format as the referenced schedule.

b) Confirm that the 2011 data provided to Mercer as shown in the reference are the same as filed with the Board in the last rate case.

c) If not, please point out any significant differences for 2011- the comparison/benchmarking year- (FTE etc.)

d) What was the weighted average annual compensation cost ($million) in 2011 of HO being 13% above the peer group median?

e) Was Mercer asked to consider Cost of Living per Statistics Canada for province/cities relevant to the peer groups?

Response

a) Please see Attachment 1.

b) The data used in the 2011 Mercer Study is similar but not 100% the same as used in the 2008 Study. Following Stakeholder input, the 2011 Study incorporated many of the suggestions made by the stakeholders.

c) In the 2011 Study, nineteen organizations were invited to participate. All thirteen of the 2008 organizations were included however, four declined. Six new organizations participated in the 2011 Study. For the benchmarked positions, incumbent data was collected for all thirty of the classifications surveyed in the 2008 Study. In addition, five new classifications were added in the 2011 Study. Due to limited data in the market, three positions were excluded in the final analysis. The 2011 Mercer Study concludes that “by including 70% of peers and 90% of jobs from the 2008 Mercer

Study, reasonable comparisons have been made and trending has been assessed." (2011 Report page 4)

d) $5.3 million

e) In the report on Page 5, Item #9, under Section 3 titled "Guiding Principles and Stakeholder Requests" it was noted that at the request of stakeholders in attendance at the May 30, 2011 stakeholder meeting in Toronto, regional costs of living amongst the study participants should be considered. However, Mercer noted that costs of living adjustments were not used in the study because "the majority of large Canadian organizations do not administer regional pay, therefore, it is not meaningful to adjust market levels based on region of operations. Furthermore, Hydro One does not manage pay on a regional basis."

EB-2010-0002: EXHIBIT I, SCHEDULE 4, TAB 35, ATTACHMENT 1

2006							
REPRESENTATION	TOTAL NO. EMPLYS	TOTAL WAGES	Base Pay	Overtime(Incl Premium)	Incentive	Other	Average Base Pay
PWU Reg	2,862	262,294,356	202,358,005	53,457,558	4,200	6,474,593	70,705
SOCIETY Reg	687	65,175,105	62,356,208	1,466,238	0	1,352,659	90,766
MCP Reg	469	59,489,433	49,471,987	55,767	4,397,964	5,563,716	105,484
Total Reg	**4,018**	**386,958,894**	**314,186,200**	**54,979,563**	**4,402,164**	**13,390,968**	**78,195**
PWU Temp	110	2,509,937	2,582,255	111,845		-184,162	23,475
Society Temp	45	1,269,193	1,336,917	19,831		-87,555	29,709
MCP Temp	7	218,523	215,324	1,165		2,035	30,761
Total Temp	**162**	**3,997,654**	**4,134,495**	**132,841**		**-269,682**	**25,522**
CASUAL	1121	68,368,828	49,638,768	11,375,466		7,354,595	44,281
TOTAL	**5301**	**459,325,376**	**367,959,463**	**66,487,869**	**4,402,164**	**20,475,881**	**69,413**

2007							
REPRESENTATION	TOTAL NO. EMPLYS	TOTAL WAGES	Base Pay	Overtime(Incl Premium)	Incentive	Other	Average Base Pay
PWU Reg	3,084	276,571,977	226,331,027	48,126,236	500	2,114,215	73,389
SOCIETY Reg	712	67,398,484	65,268,684	2,332,197	6,500	(208,898)	91,670
MCP Reg	516	67,420,494	56,665,378	63,511	6,636,752	4,054,852	109,817
Total Reg	**4,312**	**411,390,956**	**348,265,090**	**50,521,944**	**6,643,752**	**5,960,170**	**80,766**
PWU Temp	143	2,826,419	3,116,973	50,825		-341,379	21,797
Society Temp	92	3,019,335	3,350,706	19,862		-351,234	36,421
MCP Temp	8	297,149	290,565	0		6,584	36,321
Total Temp	**243**	**6,142,903**	**6,758,244**	**70,687**		**-686,029**	**27,812**
CASUAL	1338	77,992,251	59,693,098	10,343,821		7,955,332	44,614
TOTAL	**5893**	**495,526,109**	**414,716,432**	**60,936,452**	**6,643,752**	**13,229,473**	**70,374.42**

2008							
REPRESENTATION	TOTAL NO. EMPLYS	TOTAL WAGES	Base Pay	Overtime(Incl Premium)	Incentive	Other	Average Base Pay
PWU Reg	3,202	297,833,419	237,235,359	51,987,917		5,924,105.15	74,089.74
SOCIETY Reg	945	86,896,084	80,956,623	3,485,454		(232,030.09)	85,668.38
MCP Reg	567	76,768,050	63,928,396		8,073,994	10,153,617.45	112,748.49
Total Reg	**4,714**	**461,497,554**	**382,120,378**	**55,473,371**	**8,073,994**	**15,845,693**	**81,060.75**
PWU Temp	156	3,720,781	3,932,868	61,875		-273,963	25,210.70
Society Temp	68	2,899,699	2,988,034	30,367		-118,701	43,941.67
MCP Temp	12	746,558	705,783	0		6,847	58,815.23
Total Temp	**236**	**7,367,037**	**7,626,685**	**92,242**		**-385,818**	**32,316.46**
CASUAL	1597	97,252,291	74,314,292	12,197,874		10,740,125	46,533.68
TOTAL	**6547**	**566,116,882**	**464,061,355**	**67,763,487**	**8,073,994**	**26,200,000**	**70,881.53**

2009							
REPRESENTATION	TOTAL NO. EMPLYS	TOTAL WAGES	Base Pay	Overtime(Incl Premium)	Incentive	Other	Average Base Pay
PWU Reg	3,307	313,506,371	241,758,749	50,934,812.73		20,807,309	73,105.16
SOCIETY Reg	1,170	107,796,452	97,475,843	4,518,060		5,879,745	83,312.69
MCP Reg	609	83,331,393	69,012,110		9,191,373	5,065,505	113,320.38
Total Reg	**5,086**	**504,634,217**	**408,246,702**	**55,452,872.41**	**9,191,373**	**31,752,559**	**80,268.72**
PWU Temp	234	6,805,803	6,385,536	150,660.76		269,606	27,288.61
Society Temp	85	4,307,445	4,128,414	39,998.36		139,032	48,569.58
MCP Temp	14	1,016,300	997,022			9,988	71,215.84
Total Temp	**333**	**12,129,548**	**11,510,972**	**190,659**		**418,627**	**34,567.48**
CASUAL	1711	106,586,619	84,775,588	12,542,881		9,268,151	49,547.39
TOTAL	**7130**	**623,350,384**	**504,533,262**	**68,186,412**	**9,191,373**	**41,439,337**	**70,762.03**

2010							
REPRESENTATION	TOTAL NO. EMPLYS	TOTAL WAGES	Base Pay	Overtime(Incl Premium)	Incentive	Other	Average Base Pay
PWU Reg	3,667	356,105,003	276,118,903	55,318,410		24,667,689	75,298.31
SOCIETY Reg	1,479	139,154,777	126,916,047	5,268,116		6,970,615	85,812.07
MCP Reg	710	98,161,467	81,986,159	-	10,170,000	6,005,308	115,473.46
Total Reg	**5,856**	**593,421,246**	**485,021,109**	**60,586,526**	**10,170,000**	**37,643,611**	**82,824.64**
PWU Temp	234	7,051,909	6,577,102	155,181		319,626.45	28,107.27
Society Temp	85	4,458,292	4,252,267	41,198		164,827.16	50,026.67
MCP Temp	14	1,008,863	997,022			11,842	71,215.84
Total Temp	**333**	**12,519,064**	**11,826,390**	**196,379**		**496,295**	**35,514.69**
CASUAL	2221	139,178,355	113,346,100	14,844,584		10,987,671	51,033.81
Total	**8410**	**745,118,666**	**610,193,600**	**75,627,489**	**10,170,000**	**49,127,577**	**72,555.72**

2011							
REPRESENTATION	TOTAL NO. EMPLYS	TOTAL WAGES	Base Pay	Overtime(Incl Premium)	Incentive	Other	Average Base Pay
PWU Reg	3,838	382,718,704	297,664,762	58,305,549		26,748,393	77,557.26
SOCIETY Reg	1,613	151,617,876	138,414,864	5,644,430		7,558,582	85,812.07
MCP Reg	714	99,187,200	82,448,053		10,227,296	6,511,852	115,473.46
Total Reg	**6,165**	**633,523,780**	**518,527,678**	**63,949,979**	**10,227,296**	**40,818,827**	**84,108.30**
PWU Temp	234	7,600,467	7,090,320	163,560		346,587	30,300.51
Society Temp	85	4,976,339	4,753,468	44,141		178,730	55,923.15
MCP Temp	14	1,015,479	1,002,639	0		12,840	71,617.05
Total Temp	**333**	**13,592,286**	**12,846,427**	**207,701**		**538,157**	**38,577.86**
CASUAL	2290	147,815,305	120,373,456	15,527,374		11,914,474	52,564.83
TOTAL	**8,788**	**794,931,370**	**651,747,562**	**79,685,055**	**10,227,296**	**53,271,458**	**74,163.35**

2012							
REPRESENTATION	TOTAL NO. EMPLYS	TOTAL WAGES	Base Pay	Overtime(Incl Premium)	Incentive	Other	
PWU Reg	3,945	404,215,104	315,142,290	60,891,851		28,180,962	79,883.98
SOCIETY Reg	1,637	157,739,536	143,986,212	5,828,583		7,924,741	87,957.37
MCP Reg	724	103,653,130	86,110,871		10,681,651	6,860,608	118,937.67
Total Reg	**6,306**	**665,607,770**	**545,239,374**	**66,720,434**	**10,681,651**	**42,966,311**	**86,463.59**
PWU Temp	234	7,836,646	7,303,030	168,467		365,149	31,209.53
Society Temp	85	5,104,938	4,872,304	45,245		187,388	57,321.23
MCP Temp	14	1,046,246	1,032,718			13,528	73,765.56
Total Temp	**333**	**13,987,830**	**13,208,052**	**213,712**		**566,066**	**39,663.82**
CASUAL	2299	153,049,139	124,471,936	16,024,623		12,552,580	54,141.77
TOTAL	**8,938**	**832,644,738**	**682,919,362**	**82,958,769**	**10,681,651**	**56,084,956**	**76,406.28**

Energy Probe (EP) INTERROGATORY #42 List 1

Issue 7 **Are the 2013/14 Human Resources related costs (wages, salaries, benefits, incentive payments, labour productivity and pension costs) including employee levels appropriate? Has Hydro One demonstrated improvements in efficiency and value for dollar associated with its compensation costs?**

Interrogatory

Ref: Exhibit C1, Tab5, Schedule 2. Attachment 2 &
EB-2010-0002 Exhibit I-4-35, Attachment 1 and 2 &
Exhibit C2, Tab 3, Schedule 1, Tables 1, 2, 3

a) Please provide an updated copy of the Tables provided in the IR response in the second reference.
b) Update the 2011 data to show an actual-Board-Approved comparison and 2012 data to show the latest projection in comparison to Board approved.
c) Please provide the projections for the test years 2013 and 2014.
d) Please provide a comparison table that shows the increases in each category from the 2011 Board- approved data.
e) Please Compare the data by category to the first reference (Mercer)

Response

a) Exhibit C1, Tab 5, Schedule 2, Attachment 2 is the most up to date version of the data. Please see Attachment 1 to this exhibit for an update to EB-2010-0002, Exhibit I, Tab 4, Schedule 35, Attachment 2.

b) Please see Attachment 2 to this exhibit for the current data comparison to 2011 Board-Approved.

c) Exhibit C1, Tab 5, Schedule 2, Attachment 2 is the most up to date version of the data.

d) Please see Attachment 3 to this exhibit for the comparison data for Exhibit C2, Tab 3, Schedule 1, Tables 1, 2, 3.

e) The data in d) above is based on average levels and used for illustrative purposes and therefore, not comparable to the data provided in a) above.

2009	# Employees			Total Wages			Base Pay			Average Base Pay		
REP	Forecasted EB-2008-0272	Actual	Diff.	Forecasted EB-2008-0272	Actual	Diff.	Forecasted EB-2008-0272	Actual	Diff.	Forecasted EB-2008-0272	Actual	Diff.
PWU Reg	3,373	3,307	-66	$300,145,964	$313,506,371	$13,360,407	$246,658,589	$241,758,749	($4,899,840)	$73,127	$73,105	($22)
SOCIETY Reg	1,072	1,170	98	$101,174,860	$107,796,452	$6,621,593	$99,182,906	$97,475,843	($1,707,063)	$92,521	$83,313	($9,209)
MCP Reg	625	609	-16	$87,181,260	$83,331,393	($3,849,867)	$70,565,477	$69,012,110	($1,553,367)	$112,905	$113,320	$416
Total Reg	**5,070**	**5,086**	**16**	**$488,502,084**	**$504,634,217**	**$16,132,133**	**$416,406,972**	**$408,246,702**	**($8,160,270)**	**$82,132**	**$80,269**	**($1,863)**
PWU Temp	93	234	141	$1,104,782	$6,805,803	$5,701,021	$1,710,609	$6,385,536	$4,674,927	$18,394	$27,289	$8,895
Society Temp	60	85	25	$1,377,862	$4,307,445	$2,929,583	$2,034,476	$4,128,414	$2,093,938	$33,908	$48,570	$14,662
MCP Temp	5	14	9	$181,699	$1,016,300	$834,600	$169,008	$997,022	$828,013	$33,802	$71,216	$37,414
Total Temp	**158**	**333**	**175**	**$2,664,343**	**$12,129,548**	**$9,465,205**	**$3,914,094**	**$11,510,972**	**$7,596,878**	**$24,773**	**$34,567**	**$9,795**
CASUAL	**1,692**	**1,711**	**19**	**$98,033,573**	**$106,586,619**	**$8,553,046**	**$72,078,934**	**$84,775,588**	**$12,696,653**	**$42,600**	**$49,547**	**$6,948**
Total	**6,920**	**7,130**	**210**	**$589,200,000**	**$623,350,384**	**$34,150,384**	**$492,400,000**	**$504,533,262**	**$12,133,262**	**$71,156**	**$70,762**	**($394)**

2010	# Employees			Total Wages			Base Pay			Average Base Pay		
REP	Forecasted EB-2008-0272	Actuals	Diff.	Forecasted EB-2008-0272	Actual	Diff.	Forecasted EB-2008-0272	Actual	Diff.	Forecasted EB-2008-0272	Current Application Forecast	Diff.
PWU Reg	3,424	3,397	-27	$313,038,398	$327,600,666	$14,562,268	$256,721,906	$260,915,303	$4,193,397	$74,977	$76,808	$1,830
SOCIETY Reg	1,147	1,315	168	$111,006,705	$125,599,454	$14,592,749	$108,911,113	$117,961,991	$9,050,879	$94,953	$89,705	($5,248)
MCP Reg	628	651	23	$90,329,523	$88,150,303	($2,179,221)	$72,815,291	$74,337,104	$1,521,813	$115,948	$114,189	($1,759)
Total Reg	**5,199**	**5,363**	**164**	**$514,374,626**	**$541,350,422**	**$26,975,796**	**$438,448,309**	**$453,214,398**	**$14,766,088**	**$84,333**	**$84,508**	**$174**
PWU Temp	70	185	115	$665,436	$5,762,822	$5,097,386	$1,302,103	$5,627,702	$4,325,599	$18,601	$30,420	$11,819
Society Temp	25	80	55	$174,459	$5,097,027	$4,922,568	$864,530	$4,793,945	$3,929,415	$34,581	$59,924	$25,343
MCP Temp	2	21	19	$82,281	$1,366,870	$1,284,589	$68,944	$1,315,636	$1,246,693	$34,472	$62,649	$28,178
Total Temp	**97**	**286**	**189**	**$922,176**	**$12,226,719**	**$11,304,543**	**$2,235,576**	**$11,737,283**	**$9,501,707**	**$23,047**	**$41,039**	**$17,992**
CASUAL	**1,776**	**1,707**	**-69**	**$103,456,175**	**$109,976,920**	**$6,520,745**	**$77,316,115**	**$84,735,113**	**$7,418,998**	**$43,534**	**$49,640**	**$6,106**
Total	**7,072**	**7,356**	**284**	**$619,900,000**	**$663,554,061**	**$43,654,061**	**$518,000,000**	**$549,686,793**	**$31,686,793**	**$73,247**	**$74,726**	**$1,480**

2011

	# Employees			Total Wages			Base Pay			Average Base Pay		
REP	EB-2010-0002 Forecast	Actual	Diff.	EB-2010-0002 Forecast	Actual	Diff.	EB-2010-0002 Forecast	Actual	Diff.	EB-2010-0002 Forecast	Actual	Diff.
PWU Reg	3,838	3,456	-382	$382,718,704	$353,770,142	($28,948,563)	$297,664,762	$275,254,552	($22,410,209)	$77,557	$79,645	$2,088
SOCIETY Reg	1,613	1,330	-283	$151,617,876	$134,279,772	($17,338,103)	$138,414,864	$126,051,768	($12,363,095)	$85,812	$94,776	$8,964
MCP Reg	714	644	-70	$99,187,200	$88,234,049	($10,953,151)	$82,448,053	$73,880,625	($8,567,427)	$115,473	$114,721	($752)
Total Reg	**6,165**	**5,430**	**-735**	**$633,523,780**	**$576,283,963**	**($57,239,817)**	**$518,527,678**	**$475,186,946**	**($43,340,732)**	**$84,108**	**$87,511**	**$3,403**
PWU Temp	234	211	-23	$7,600,467	$5,508,958	($2,091,510)	$7,090,320	$5,331,454	($1,758,867)	$30,301	$25,268	($5,033)
Society Temp	85	79	-6	$4,976,339	$5,234,552	$258,213	$4,753,468	$4,983,808	$230,340	$55,923	$63,086	$7,163
MCP Temp	14	22	8	$1,015,479	$1,660,391	$644,912	$1,002,639	$1,612,601	$609,962	$71,617	$73,300	$1,683
Total Temp	**333**	**312**	**-21**	**$13,592,286**	**$12,403,901**	**($1,188,385)**	**$12,846,427**	**$11,927,862**	**($918,565)**	$38,578	$38,230	**($348)**
CASUAL	**2,290**	**1,488**	**-802**	**$147,815,305**	**$106,663,199**	**($41,152,105)**	**$120,373,456**	**$80,054,576**	**($40,318,881)**	$52,565	$53,800	**$1,235**
Total	**8,788**	**7,230**	**-1558**	**$794,931,370**	**$695,351,063**	**($99,580,307)**	**$651,747,562**	**$567,169,384**	**($84,578,178)**	**$74,163**	**$78,447**	**$4,283**

2012

	# Employees			Total Wages			Base Pay			Average Base Pay		
REP	EB-2010-0002 Forecast	Current Application	Diff.	EB-2010-0002 Forecast	Current Application Forecast	Diff.	EB-2010-0002 Forecast	Current Application Forecast	Diff.	EB-2010-0002 Forecast	Current Application Forecast	Diff.
PWU Reg	3,945	3,512	-433	$404,215,104	$366,737,424	($37,477,679)	$315,142,290	$285,742,261	($29,400,030)	$79,884	$81,357	$1,473
SOCIETY Reg	1,637	1,371	-266	$157,739,536	$139,579,280	($18,160,256)	$143,986,212	$131,098,578	($12,887,634)	$87,957	$95,603	$7,645
MCP Reg	724	659	-65	$103,653,130	$91,074,470	($12,578,661)	$86,110,871	$76,345,990	($9,764,881)	$118,938	$115,764	($3,174)
Total Reg	**6,306**	**5,543**	**-763**	**$665,607,770**	**$597,391,174**	**($68,216,596)**	**$545,239,374**	**$493,186,828**	**($52,052,546)**	$86,464	$88,975	**$2,511**
PWU Temp	234	232	-2	$7,836,646	$5,674,226	($2,162,420)	$7,303,030	$5,491,397	($1,811,633)	$31,210	$23,660	($7,550)
Society Temp	85	87	2	$5,104,938	$5,365,416	$260,478	$4,872,304	$5,108,403	$236,099	$57,321	$58,785	$1,464
MCP Temp	14	24	10	$1,046,246	$1,708,832	$662,586	$1,032,718	$1,660,979	$628,261	$73,766	$68,635	($5,130)
Total Temp	**333**	**343**	**10**	**$13,987,830**	**$12,748,474**	**($1,239,356)**	**$13,208,052**	**$12,260,779**	**($947,273)**	$39,664	$35,725	**($3,939)**
CASUAL	**2,299**	**1,516**	**-783**	**$153,049,139**	**$112,013,563**	**($41,035,576)**	**$124,471,936**	**$84,070,216**	**($40,401,720)**	$54,142	$55,455	**$1,314**
Total	**8,938**	**7,402**	**-1536**	**$832,644,738**	**$722,153,211**	**($110,491,527)**	**$682,919,362**	**$589,517,824**	**($93,401,538)**	**$76,406**	**$79,641**	**$3,235**

EB-2010-0002 | EB-2012-0031 | Difference

Table 1, Regional Maintainer Lines

Year	Total Wages	Base	Overtime	Incentive	Other*	Total Wages	Base	Overtime	Incentive	Other*	Total Wages	Base	Overtime	Incentive	Other*
2009	$121,772	$80,989	$37,851	$0	$2,932	$121,772	$80,989	$37,851	$0	$2,932	$0	$0	$0	$0	$0
2010	$125,425	$83,418	$38,987	$0	$3,020	$125,425	$83,418	$38,987	$0	$3,020	$0	$0	$0	$0	$0
2011	$129,186	$85,920	$40,156	$0	$3,110	$121,871	$82,122	35028.00	$0	$4,720	($7,315)	($3,798)	($5,128)	$0	$1,610
2012	$133,042	$88,479	$41,360	$0	$3,203	$125,524	$84,585	$36,078	$0	$4,861	($7,518)	($3,894)	($5,282)	$0	$1,658

EB-2010-0002 | EB-2012-0031 | Difference

Table 2, MP4

Year	Total Wages	Base	Overtime	Incentive	Other*	Total Wages	Base	Overtime	Incentive	Other*	Total Wages	Base	Overtime	Incentive	Other*
2009	$104,383	$101,148	$1,319	$0	$1,916	$104,383	$101,148	$1,319	$0	$1,916	$0	$0	$0	$0	$0
2010	$107,514	$104,182	$1,359	$0	$1,973	$107,514	$104,182	$1,359	$0	$1,973	$0	$0	$0	$0	$0
2011	$110,201	$106,786	$1,393	$0	$2,022	$105,311	$99,401	3581.00	$0	$2,329	($4,890)	($7,385)	$2,188	$0	$307
2012	$112,954	$109,455	$1,427	$0	$2,072	$107,943	$101,886	$3,670	$0	$2,387	($5,011)	($7,569)	$2,243	$0	$315

EB-2010-0002 | EB-2012-0031 | Difference

Table 3, Band 7 (MCP)

Year	Total Wages	Base	Overtime	Incentive	Other*	Total Wages	Base	Overtime	Incentive	Other*	Total Wages	Base	Overtime	Incentive	Other*
2009	$123,456	$103,444	$0	$12,000	$8,012	$123,456	$103,444	$0	$12,000	$8,012	$0	$0	$0	$0	$0
2010	$128,129	$107,416	$0	$12,460	$8,253	$128,129	$107,416	$0	$12,460	$8,253	$0	$0	$0	$0	$0
2011	$128,129	$107,416	$0	$12,460	$8,253	$123,461	$107,565	0.00	$8,683	$7,210	($4,668)	$149	$0	($3,777)	($1,043)
2012	$131,971	$110,638	$0	$12,833	$8,500	$125,309	$109,178	$0	$8,813	$7,318	($6,662)	($1,460)	$0	($4,020)	($1,182)

Energy Probe (EP) INTERROGATORY #43 List 1

Issue 7 **Are the 2013/14 Human Resources related costs (wages, salaries, benefits, incentive payments, labour productivity and pension costs) including employee levels appropriate? Has Hydro One demonstrated improvements in efficiency and value for dollar associated with its compensation costs?**

Interrogatory

Ref: Exhibit C1, Tab 5, Schedule 2, Page 12

Table 1 on Page 12 shows a comparison of wages between Hydro One and other LDCs. Line 16 notes that the Powerline maintainer position has been used in the comparison although Hydro One uses a different position called Regional Maintainer. Please provide the wage rate of the Regional Maintainer for comparison in the table.

Response

The rate for the Regional Maintainer- Lines is $41.85/hour.

Energy Probe (EP) INTERROGATORY #44 List 1

Issue 7 **Are the 2013/14 Human Resources related costs (wages, salaries, benefits, incentive payments, labour productivity and pension costs) including employee levels appropriate? Has Hydro One demonstrated improvements in efficiency and value for dollar associated with its compensation costs?**

Interrogatory

Ref: Exhibit C1, Tab 5, Schedule 2, Page 12

Lines 18-21 describe the additional duties of a Regional Line Maintainer that distinguish it from the Powerline Maintainer.

a) Please describe in more detail the "additional technical, trade and customer relations skills" referred to.

b) How did Hydro One determine that other LDC Powerline Maintainers do not act as lead hand, contract monitor or hold work protection? Please provide any documents, studies or surveys conducted to arrive at that conclusion.

Response

a) The Regional Maintainer classification requires incumbents to act as a contract monitor. Previous to the establishment of this classification, acting as a contract monitor would attract extra compensation. The Regional Maintainer- Lines is also required to be aware and advise on the appropriate design standards to comply with the appropriate regulations without the need for obtaining engineering or technician approval. The Regional Maintainer-Lines classification also requires lead hand knowledge to ensure the safe and efficient execution of work.

b) The evidence provided is based upon the opinion and expertise of internal management staff who are familiar with other LDC operations. In addition, Hydro One has acquired LDC's in the past and the acquired employees underwent skill assessments. These assessments have identified that LDC employees are not trained at the level of our employees and they have limited experience in our complex work environment.

Energy Probe (EP) INTERROGATORY #45 List 1

Issue 7 **Are the 2013/14 Human Resources related costs (wages, salaries, benefits, incentive payments, labour productivity and pension costs) including employee levels appropriate? Has Hydro One demonstrated improvements in efficiency and value for dollar associated with its compensation costs?**

Interrogatory

Ref: Exhibit C1, Tab 5, Schedule 2, Page 13

Lines 2-6 on Page 13 state that work and skills required at Hydro One are more complex than those required at other LDCs.

a) Please explain how a rural work setting is more complex than an urban setting.

b) What is the basis for the statement that proficiency on overhead, underground and submarine cable is not typical of the PLM role in other LDCs

Response

a) A rural work setting has unique challenges such as geography and a requirement to work with equipment and systems not normally required in other LDC's. For example, in a rural setting, Hydro One staff often work in and around swamps, thus requiring employees to work off boats and barges. Employees must be familiar and trained to operate equipment such as muskegs, timberjacks, ATV's, snowmobiles and boats. Line staff are often required to work off -road and as such, do not have the mechanical means like a crane to perform lifts. As a result, Hydro One staff need to be trained and be competent in a variety of rigging methods to accomplish work. Hydro One staff are trained to work on both the distribution and transmission systems. LDC staff would work on a distribution system only. In terms of live line work, LDC staff would perform live line work on the distribution system but they would not be qualified to perform live line work on Hydro One's high voltage system.

b) LDC staff would work on overhead and underground cable and to a lessor extent, may work on submarine cable. Hydro One RM- Lines staff are qualified and are required to work on overhead, underground and submarine cables at any given time. As such, staff must keep their skill level current so they can work on any type of these cables. Submarine cables are a particular challenge since the work typically involves laying a large amount of cable and trenching and moving heavy equipment under inhospitable conditions.

Energy Probe (EP) INTERROGATORY #46 List 1

Issue 7 **Are the 2013/14 Human Resources related costs (wages, salaries, benefits, incentive payments, labour productivity and pension costs) including employee levels appropriate? Has Hydro One demonstrated improvements in efficiency and value for dollar associated with its compensation costs?**

Interrogatory

Ref: Exhibit C1, Tab 5, Schedule 2, Attachment 1 – The Mercer Study

Page 6 refers to weighting of the analysis by organization to ensure that no one organization biased the results of the comparison. Please explain what organization weighting is, how it is computed and what undesirable effects it avoids in the analysis.

Response

"Organization weighted" refers to giving equal weight to each organization in the sample rather than weighting the data by the number of employees represented in the survey sample.

It is calculated by conducting the following steps:

1. Averaging the data points for each organization in the sample to obtain one single statistic for each
2. Computing the desired statistic (i.e., P25, P50, P75) based on the single statistic for each company

It avoids having the pay practices of the largest organizations, measured by number people matched to the survey, having a large impact on the survey findings.

Energy Probe (EP) INTERROGATORY #47 List 1

Issue 7 **Are the 2013/14 Human Resources related costs (wages, salaries, benefits, incentive payments, labour productivity and pension costs) including employee levels appropriate? Has Hydro One demonstrated improvements in efficiency and value for dollar associated with its compensation costs?**

Interrogatory

Ref: Exhibit C1, Tab 5, Schedule 2, Attachment 1 – The Mercer Study

Page 11 refers to recent amendments to pension and benefit plans for new employees. Please compare the major features of the two plans indicating where cost savings are expected and how much on a percentage basis those savings are between the old and new plans.

Response

MCP employees hired on or after January 1, 2004 and Society represented employees hired after November 17, 2005 are eligible to join a new pension plan that is less provident than the existing plan for 'grandfathered' employees. The main differences between the two pension plans are:

Benefit	**Old Pension Plan**	**New Pension Plan**
Final Average Earnings	Highest 36 consecutive months	Highest 60 consecutive months
Bridge benefit	Yes	None
Indexing	100% Ontario CPI (max 8%)	75% Ontario CPI max 5%
Early unreduced retirement	Rule of 82	Rule of 85
Eligibility for post-retirement benefits	2 years pension plan membership	2 years of pension plan membership and 10 years of continuous service with Hydro One

The 'new pension" plan is 25% less expensive than the older pension plan.

In addition, MCP employees hired on or after January 1, 2004 are enrolled in a benefit program called "Personal Choice". MCP employees hired before this date are enrolled in a benefit program called "Powerflex". The Personal Choice benefit program has higher deductibles, more caps and more co-insurance than the Powerflex benefit program and the Health and Dental benefits provided to PWU and Society represented employees.

The average annual cost per subscriber for Powerflex and Personal Choice is approximately $4500 and $1800 respectively.

Energy Probe (EP) INTERROGATORY #48 List 1

Issue 7 **Are the 2013/14 Human Resources related costs (wages, salaries, benefits, incentive payments, labour productivity and pension costs) including employee levels appropriate? Has Hydro One demonstrated improvements in efficiency and value for dollar associated with its compensation costs?**

Interrogatory

Ref: Exhibit C1, Tab 5, Schedule 2, Attachment 1 – The Mercer Study

Table 5 on Page 13 shows compensation for non-represented staff. Footnote 5 notes that future compensation estimates in the Table assume that all employees in the group are covered by the new pension and benefits programs. The overall affect appears to be 1% (from –17% to –18% of market P50). Is this a valid conclusion to draw from the table?

Response

The conclusion is valid. The new Hydro One pension and benefit plans and the new market pension and benefit plans are of lower relative value than the old plans. The value of Hydro One's plans dropped more than the market median value by 1%.

Energy Probe (EP) INTERROGATORY #49 List 1

Issue 7 **Are the 2013/14 Human Resources related costs (wages, salaries, benefits, incentive payments, labour productivity and pension costs) including employee levels appropriate? Has Hydro One demonstrated improvements in efficiency and value for dollar associated with its compensation costs?**

Interrogatory

Ref. Exhibit C1, Tab 5, Schedule 3 - Pension Costs

a) What effect would a 1% increase in return on the plan assets have on pension contributions by the employer?

b) Please undertake to file copy of the 2012 Actuarial valuation when available, since this may affect the rest years

Response

a) A one-time increase in return on the plan assets of 1%, ceteris paribus, would result in a decrease of pension contributions of approximately $1 million to $4 million per year.

A long-term assumed increase of 1% per year would result in a decrease of pension contributions of approximately 50% per year.

b) Please find attached 2011 valuation. Hydro One does not intend to have an actuarial valuation prepared as at December 31, 2012 as one was prepared as at December 31, 2011 and Hydro One is not required to have another one prepared before December 31, 2014.

Hydro One's current application is based on the 2009 valuation. The application was not updated for the 2011 valuation.

MERCER

CONSULTING. OUTSOURCING. INVESTMENTS.

HYDRO ONE PENSION PLAN

REPORT ON THE ACTUARIAL VALUATION FOR FUNDING PURPOSES AS AT DECEMBER 31, 2011

MAY 2012

Ontario Registration Number: 1059104
Canada Revenue Agency Registration Number: 1059104

MARSH & McLENNAN COMPANIES

Note to reader regarding actuarial valuations:

This valuation report may not be relied upon for any purpose other than those explicitly noted in the Introduction, nor may it be relied upon by any party other than the parties noted in the Introduction. Mercer is not responsible for the consequences of any other use. A valuation report is a snapshot of a plan's estimated financial condition at a particular point in time; it does not predict a pension plan's future financial condition or its ability to pay benefits in the future. If maintained indefinitely, a plan's total cost will depend on a number of factors, including the amount of benefits the plan pays, the number of people paid benefits, the amount of plan expenses, and the amount earned on any assets invested to pay the benefits. These amounts and other variables are uncertain and unknowable at the valuation date.

To prepare the results in this report, actuarial assumptions are used to model a single scenario from a range of possibilities for each valuation basis. The results based on that single scenario are included in this report. However, the future is uncertain and the plan's actual experience will differ from those assumptions; these differences may be significant or material. Different assumptions or scenarios within the range of possibilities may also be reasonable, and results based on those assumptions would be different. Furthermore, actuarial assumptions may be changed from one valuation to the next because of changes in regulatory and professional requirements, developments in case law, plan experience, changes in expectations about the future and other factors.

The valuation results shown in this report also illustrate the sensitivity to one of the key actuarial assumptions, the discount rate. We note that the results presented herein rely on many assumptions, all of which are subject to uncertainty, with a broad range of possible outcomes and the results are sensitive to all the assumptions used in the valuation.

Should the plan be wound up, the going concern funded status and solvency financial position, if different from the wind-up financial position, become irrelevant. The hypothetical wind-up financial position estimates the financial position of the plan assuming it is wound-up on the valuation date. Emerging experience will affect the wind-up financial position of the plan assuming it is wound-up in the future. In fact, even if the plan were wound-up on the valuation date, the financial position would continue to fluctuate until the benefits are fully settled.

Because actual plan experience will differ from the assumptions used in this valuation, decisions about benefit changes, investment policy, funding amounts, benefit security and/or benefit-related issues should be made only after careful consideration of alternative future financial conditions and scenarios, and not solely on the basis of a valuation report or reports.

CONTENTS

1

Summary of Results

(in 000s)	31.12.11	31.12.09
Going Concern Financial Status		
Smoothed value of assets	$5,175,593	$4,771,203
Actuarial liability	$5,512,107	$5,205,515
Prior Year Credit Balance	$161,190	$0
Funding excess (shortfall)	($497,704)	($434,312)
Hypothetical Wind-up Financial Position		
Wind-up assets	$4,795,159	$4,334,416
Wind-up liability	$8,032,425	$6,468,702
Wind-up excess (shortfall)	($3,237,266)	($2,134,286)
Funding Requirements in the Year Following the Valuation [1]	**2012**	**2010**
Total current service cost	$126,221	$113,576
Estimated member's required contributions	($26,849)	($22,543)
Estimated employer's current service cost	$99,372	$91,033
Employer's current service cost as a percentage of members' pensionable earnings	18.9%	19.6%
Minimum annual special payments	$59,675	$48,380
Estimated minimum employer contribution	$159,047	$139,413
Estimated maximum eligible employer contribution	$3,336,638	$2,225,319
Next required valuation date	December 31, 2014	December 31, 2012

[1] Provided for reference purposes only. Contributions must be remitted to the Plan in accordance with the Minimum Funding Requirements and Maximum Eligible Contributions sections of this report.

2

Introduction

To Hydro One Inc.

At the request of Hydro One Inc., we have conducted an actuarial valuation of the Hydro One Pension Plan (the "Plan"), sponsored by Hydro One Inc. (the "Company"), as at the valuation date, December 31, 2011. We are pleased to present the results of the valuation.

Purpose

The purpose of this valuation is to determine:

- The funded status of the plan as at December 31, 2011 on going concern, hypothetical wind-up and solvency bases
- The minimum required funding contributions from 2012, in accordance with the *Pension Benefits Act (Ontario)*
- The maximum permissible funding contributions from 2012, in accordance with the *Income Tax Act*

The information contained in this report was prepared for the internal use of the Company and for filing with the Financial Services Commission of Ontario and with the Canada Revenue Agency, in connection with our actuarial valuation of the Plan. This report will be filed with the Financial Services Commission of Ontario and with the Canada Revenue Agency. This report is not intended or suitable for any other purpose.

In accordance with pension benefits legislation, the next actuarial valuation of the Plan will be required as at a date not later than December 31, 2014, or as at the date of an earlier amendment to the Plan.

Terms of Engagement

In accordance with our terms of engagement with the Hydro One Inc., our actuarial valuation of the Plan is based on the following material terms:

- It has been prepared in accordance with applicable pension legislation and actuarial standards of practice in Canada.
- As instructed by the Hydro One Inc., we have reflected a margin for adverse deviations in our going concern valuation by reducing the going concern discount rate by 0.91% per year.
- We have reflected the Hydro One Inc. decisions for determining the solvency funding requirements, summarized as follows:
  - The same scenario was hypothesized for both the hypothetical wind-up and solvency valuations.
  - Certain excludable benefits were excluded from the solvency liabilities.
  - Solvency smoothing was used.
  - No funding relief measures have been applied.

See the Valuation Results - Solvency section of the report for more information.

Events Since the Last Valuation at December 31, 2009

Pension Plan

On March 19, 2010, the Superintendent of Financial Services (the "Superintendent") ordered that the Plan be partially wound up effective December 31, 2002 (the "Partial Wind-Up Date") in respect of a group of 73 Management Compensation Plan Members whose employment was terminated effective as of a date between September 1, 2002 and December 31, 2002, as a consequence of the merger of Hydro One Networks Inc. and Hydro One Network Services Inc. (the "Affected Members"). The partial wind-up report was filed with the Financial Services Commission of Ontario in June 2010. The partial wind-up shortfall was fully funded in 2011 and the benefits for Affected Members were settled on June 1, 2011. The impact of the partial wind-up has been fully reflected in this report.

There have been no other special events since the last valuation date.

This valuation reflects the provisions of the Plan as at December 31, 2011. The Plan was amended effective April 1, 2011 to increase employee contributions for members of the Power Workers Union by 0.5% of pensionable earnings. The Plan has not otherwise been amended since the date of the previous valuation, and we are not aware of any pending definitive or virtually definitive amendments coming into effect during the period covered by this report. The Plan provisions are summarised in Appendix F.

Assumptions

We have used the same going concern valuation assumptions and methods as were used for the previous valuation, except for the following:

	Current valuation	Previous valuation
Interest on employee contributions:	2.00%	4.50%

The hypothetical wind-up and solvency assumptions have been updated to reflect market conditions at the valuation date.

A summary of the going concern, and hypothetical wind-up and solvency methods and assumptions are provided in Appendices C and D, respectively.

Regulatory Environment and Actuarial Standards

There have been a number of changes to the Pension Benefits Act (Ontario) (the "Act") and regulations which impact the funding of the Plan.

The Government of Ontario has announced its intentions to makes changes to the funding requirements for pension plans registered in Ontario. Since then Bill 120 received Royal assent. However, the intended changes to the funding requirements which impact the funding of single-employer pension plans will be contained in regulations which have not yet been adopted.

Certain changes to the Canadian Institute of Actuaries Standard of Practice for determining pension commuted values ("CIA CV Standard") became effective on February 1, 2011. The changes affect the mortality assumptions used to value the solvency and wind-up liabilities for benefits assumed to be settled through a lump sum transfer. The financial impact of the change in the CIA CV Standard has been reflected in this actuarial valuation.

A new Canadian actuarial Standard of Practice – *Practice Specific Standards of Practice for Pension Plans* became effective December 31, 2010 (the "CIA Pension Standards"). The requirements of the CIA Pension Standards have been reflected in this report.

Subsequent Events

After checking with representatives of the Company, to the best of our knowledge there have been no events subsequent to the valuation date which, in our opinion, would have a material impact on the results of the valuation. Our valuation reflects the financial position of the Plan as of the valuation date and does not take into account any experience after the valuation date.

Impact of Case Law

This report has been prepared on the assumption that all of the assets in the pension fund are available to meet all of the claims on the Plan. We are not in a position to assess the impact that the Ontario Court of Appeal's decision in *Aegon Canada Inc. and Transamerica Life Canada versus ING Canada Inc.* or similar decisions in other jurisdictions might have on the validity of this assumption.

On July 29, 2004, the Supreme Court of Canada dismissed the appeal in Monsanto Canada Inc. versus Superintendent of Financial Services ("*Monsanto*"), thereby upholding the requirements to distribute surplus on partial plan wind-up under The *Pension Benefits Act (Ontario).* The decision has retroactive application and applies on the termination of Ontario employees if they are included in a partial plan wind-up, regardless of the province in which the pension plan is registered.

We are not aware of any partial plan wind-up having been declared in respect of the Plan where the Monsanto decision may apply. In preparing this actuarial valuation, we have therefore assumed that all the Plan's assets are available to cover the Plan's liabilities presented in this report. The subsequent declaration of a partial wind-up of the Plan where *Monsanto* may apply in respect of a past event, or disclosure of an existing past partial wind-up, could cause an additional claim on the Plan's assets, the consequences of which would be addressed in a subsequent report. We note the discretionary nature of the power of the regulatory authorities to declare partial wind-ups and the lack of clarity with respect to the retroactive scope of that power. We are making no representation as to whether the regulatory authorities might declare a partial wind-up in respect of other events in the Plan's history.

3

Valuation Results – Going Concern

Financial Status

A going concern valuation compares the relationship between the value of Plan assets and the present value of expected future benefit cash flows in respect of accrued service, assuming the Plan will be maintained indefinitely.

The results of the current valuation, compared with those from the previous valuation, are summarized as follows:

(in 000s)	31.12.11	31.12.09
Assets		
Market value of assets (including in-transits)	$4,806,893	$4,346,343
Asset smoothing adjustment	$368,700	$424,860
Smoothed value of assets	$5,175,593	$4,771,203
Going concern funding target		
• Active members	$2,185,022	$2,061,480
• Pensioners and survivors	$3,286,025	$3,100,493
• Deferred pensioners	$40,279	$43,524
• Additional voluntary contributions	$781	$18
Total	$5,512,107	$5,205,515
Funding excess (shortfall)	($336,514)	($434,312)
Prior Year Credit Balance	($161,190)	$0
Net position	($497,704)	($434,312)

The going concern funding target includes a provision for adverse deviations.

Reconciliation of Financial Status

Funding excess (shortfall) as at previous valuation		($434,312)
Interest on funding excess (funding shortfall) at 5.50% per year		($49,088)
Employer's special payments, with interest		$271,200
Expected funding excess (funding shortfall)		($212,200)
Net experience gains (losses)		
• Net investment return	($85,639)	
• Increases in pensionable earnings	$23,101	
• Increase in YMPE/maximum pension	($308)	
• Indexation	($20,984)	
• Mortality	$11,187	
• Retirement	($23,633)	
• Termination	($3,959)	
• Disability	($11,201)	
Total experience gains (losses)	($111,436)	($111,436)
Impact of changes in assumptions		$298
Net impact of other elements of gains and losses		($13,176)
Funding excess (shortfall) as at current valuation		($336,514)

Current Service Cost

The current service cost is an estimate of the present value of the additional expected future benefit cash flows in respect of pensionable service that will accrue after the valuation date, assuming the Plan will be maintained indefinitely.

The current service cost during the year following the valuation date compared with the corresponding value determined in the previous valuation, is as follows:

(in $000s)	2012	2010
Total current service cost	$126,221	$113,576
Estimated members' required contributions	($26,849)	($22,543)
Estimated employer's current service cost	$99,372	$91,033
Employer's current service cost expressed as a percentage of members' pensionable earnings	18.9%	19.6%

The key factors that have caused a change in the employer's current service cost since the previous valuation are summarized in the following table:

Employer's current service cost as at previous valuation	19.6%
Demographic changes	(0.4%)
Plan amendments	(0.3%)
Employer's current service cost as at current valuation	18.9%

Discount Rate Sensitivity

The following table summarises the effect on the going concern funding target shown in this report of using a discount rate which is 1.00% lower than that used in the valuation:

Scenario	Valuation Basis	Reduce Discount Rate by 1%
(in 000s)		
Going concern funding target	$5,512,107	$6,352,769
Current service cost		
• Total current service cost	$126,221	$162,417
• Estimated members' required contributions	($26,849)	($26,849)
• Estimated employer's current service cost	$99,372	$135,568

4

Valuation Results – Hypothetical Wind-up

Financial Position

When conducting a hypothetical wind-up valuation, we determine the relationship between the respective values of the Plan's assets and its liabilities assuming the Plan is wound up and settled on the valuation date, assuming benefits are settled in accordance with the Act and under circumstances producing the maximum wind-up liabilities on the valuation date. However, to the extent permitted by law, the actuary may disregard:

- Benefits that would not be payable under the hypothesized scenario
- Plan member earnings after the valuation date.

The hypothetical wind-up financial position as of the valuation date, compared with that at the previous valuation, is as follows:

(in $000s)	31.12.11	31.12.09
Assets		
Market value of assets (including in-transits)	$4,806,893	$4,346,343
Termination expense provision	($11,734)	($11,927)
Wind-up assets	$4,795,159	$4,334,416
Present value of accrued benefits for:		
• active members	$3,493,583	$2,718,326
• pensioners and survivors	$4,474,424	$3,696,529
• deferred pensioners	$63,637	$53,829
• additional voluntary contributions	$781	$18
Total wind-up liability	$8,032,425	$6,468,702
Wind-up excess (shortfall)	($3,237,266)	($2,134,286)

5

Valuation Results – Solvency

Overview

The Act also requires the financial position of the Plan to be determined on a solvency basis. The financial position on a solvency basis is determined in a similar manner to the Hypothetical Wind-up Basis, except for the following:

Exceptions	**Reflected in valuation based on the terms of engagement**
The circumstance under which the Plan is assumed to be wound-up could differ for the solvency and hypothetical wind-up valuations.	The same circumstances were assumed for the solvency valuation as were assumed for the hypothetical wind-up.
Certain benefits can be excluded from the solvency financial position. These include: (a) any escalated adjustment (e.g. indexing), (b) certain plant closure benefits, (c) certain permanent layoff benefits, (d) special allowances other than funded special allowances, (e) consent benefits other than funded consent benefits, (f) prospective benefit increases, (g) potential early retirement window benefit values, and (h) pension benefits and ancillary benefits payable under a qualifying annuity contract.	The following benefits were excluded from the solvency liabilities shown in this valuation: • Indexing of benefits
The financial position on the solvency basis needs to be adjusted for any Prior Year Credit Balance.	A Prior Year Credit Balance has been reflected in the financial position
The solvency financial position can be determined by smoothing assets and the solvency discount rate over a period of up to 5 years.	Solvency assets and liabilities were smoothed over 5 years.
The benefit rate increases coming into effect after the valuation date can be reflected in the solvency valuation.	Not applicable.

Financial Position

The financial position on a solvency basis, compared with the corresponding figures from the previous valuation, is as follows:

	31.12.11	31.12.09
Assets		
Market value of assets (including in-transits)	$4,806,893	$4,346,343
Termination expense provision	($11,734)	($11,927)
Net assets	$4,795,159	$4,334,416
Present value of special payments	$269,350	$216,275
	$5,064,509	$4,550,691
Liabilities		
Total hypothetical wind-up liabilities	$8,032,425	$6,468,702
Difference in circumstances of assumed wind-up	$0	$0
Value of excluded benefits	($2,398,746)	($1,859,412)
Liabilities on a solvency basis	$5,633,679	$4,609,290
Surplus (shortfall) on a market value basis	($569,170)	($58,599)
Prior Year Credit Balance	($161,190)	$0
Liability smoothing adjustment	$626,531	$118,283
Asset smoothing adjustment	$368,700	$424,860
Surplus (shortfall) on a solvency basis	$264,871	$484,544
Solvency Ratio	100%	100%

Discount Rate Sensitivity

The following table summarises the effect on the solvency liabilities shown in this report of using a discount rate which is 1.00% lower than that used in the valuation:

Scenario (in 000s)	Valuation Basis	Reduce Discount Rate by 1%
Total hypothetical solvency liability	$5,633,679	$6,413,186

Solvency Incremental Cost to December 31, 2014

The solvency incremental cost is an estimate of the present value of the projected change in the solvency liabilities from the valuation date until the next scheduled valuation date, adjusted for the benefit payments expected to be made in that period.

The solvency incremental cost determined in this valuation is as follows:

	31.12.11
Number of years covered by report	3 years
Total solvency liabilities at the valuation date (A)	$5,633,679
Present value of projected solvency liability at the next required valuation (including expected new entrants) plus benefit payments until the next required valuation (B)	$6,310,401
Solvency incremental cost (B – A)	$676,722

The incremental cost is not an appropriate measure of the contributions that would be required to maintain the financial position of the Plan on a solvency basis unchanged from the valuation date and the next required valuation date, if actual experience is exactly in accordance with the going concern valuation assumptions. This is because it does not reflect the fact that the expected return on plan assets (based on the going concern assumptions) is greater than the discount rate used to determine the solvency liabilities.

6

Minimum Funding Requirements

The Act prescribes the minimum contributions that Hydro One Inc. must make to the Plan. The minimum contributions in respect of a defined benefit component of a pension plan are comprised of going concern current service cost and special payments to fund any going concern or solvency shortfalls.

On the basis of the assumptions and methods described in this report, the rule for determining the minimum required employer monthly contributions, as well as an estimate of the employer contributions, from the valuation date until the next required valuation are as follows:

	Employer's contribution rule			Estimated employer's contributions	
Period beginning	Monthly current service cost[2]	Explicit monthly expense allowance	Minimum monthly special payments	Monthly current service cost	Total minimum monthly contributions
December 31, 2011	18.9%	$0	$4,972,906	$8,281,000	$13,253,906
December 31, 2012	18.9%	$0	$4,972,906	$8,509,000	$13,481,906
December 31, 2013	18.9%	$0	$4,972,906	$8,743,000	$13,715,906

The estimated contribution amounts above are based on projected members' pensionable earnings. Therefore the actual employer's current service cost will be different from the above estimates and, as such, the contribution requirements should be monitored closely to ensure contributions are made in accordance with the Act.

The development of the minimum special payments is summarized in Appendix A.

The estimated minimum employer contribution for 2012 if the Prior Year Credit Balance were fully applied is $0.

Other Considerations

Differences between Valuation Bases

There is no provision in the minimum funding requirements to fund the difference between the hypothetical wind-up and solvency shortfalls, if any.

In addition, although minimum funding requirements do include a requirement to fund the going concern current service cost, there is no requirement to fund the expected growth in the hypothetical wind-up or solvency liability after the valuation date, which could be greater than the going concern current service cost.

[2] Expressed as a percentage of members' pensionable earnings.

Timing of Contributions

Funding contributions are due on monthly basis. Contributions for current service cost must be made within 30 days following the month to which they apply. Special payment contributions must be made in the month to which they apply.

Retroactive Contributions

The Company must contribute the excess, if any, of the minimum contribution recommended in this report over contributions actually made in respect of the period following the valuation date. This contribution, along with an allowance for interest, is due no later than 60 days following the date this report is filed.

Payment of Benefits

The Act imposes certain restrictions on the payment of lump sums from the Plan when the transfer ratio revealed in an actuarial valuation is less than one. If the transfer ratio shown in this report is less than one, the plan administrator should ensure that the monthly special payments are sufficient to meet the requirements of the Act to allow for the full payment of benefits, and otherwise should take the prescribed actions.

Additional restrictions are imposed when:

- The transfer ratio revealed in the most recently filed actuarial valuation is less than one and the administrator knows or 'ought to know' that the transfer ratio of the Plan has declined by 10% or more since the date the last valuation was filed.

- The transfer ratio revealed in the most recently filed actuarial valuation is greater than or equal to one and the administrator knows or 'ought to know' that the transfer ratio of the Plan has declined to less than 0.9 since the date the last valuation was filed.

As such, the administrator should monitor the transfer ratio of the Plan and, if necessary, take the prescribed actions.

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Maximum Eligible Contributions

The *Income Tax Act* (the "ITA") limits the amount of employer contributions that can be remitted to the defined benefit component of a registered pension plan. However, notwithstanding the limit imposed by the ITA, for plans which are not 'Designated' as defined in the ITA, in general, the minimum required contributions under the Act can be remitted.

In accordance with Section 147.2 of the ITA and *Income Tax Regulation* 8516, for a plan which is underfunded on either a going concern or on a hypothetical wind-up basis the maximum permitted contributions are equal to the employer's current service cost, including the explicit expense allowance if applicable, plus the greater of the going concern funding shortfall and hypothetical wind-up shortfall.

For a plan which is fully funded on both going concern and hypothetical wind-up bases, the employer can remit a contribution equal to the employer's current service cost, including the explicit expense allowance if applicable, as long as the surplus in the plan does not exceed a prescribed threshold. Specifically, in accordance with Section 147.2 of the ITA, for a plan which is fully funded on both going concern and hypothetical wind-up bases, the plan may not retain its registered status if the employer makes a contribution while the going concern funding excess exceeds 25% of the going concern funding target.

Schedule of Maximum Contributions

The Company is permitted to fully fund the greater of the going concern and hypothetical wind-up shortfalls; $3,237,266,000 as well as make current service cost contributions. The portion of this contribution representing the payment of the hypothetical wind-up shortfall can be increased with interest at 4.18% per year from the valuation date to the date the payment is made, and must be reduced by the amount of any deficit funding made from the valuation date to the date the payment is made.

Assuming the Company contributes the greater of the going concern and hypothetical wind-up shortfall of $3,237,266,000 as of the valuation date, the rule for determining the estimated maximum eligible annual contributions, as well as an estimate of the maximum eligible contributions until the next valuation are as follows:

	Employer's contribution rule			Estimated employer's contributions
Year beginning	**Monthly current service cost[3]**	**Monthly expense allowance**	**Deficit Funding**	**Monthly current service cost**
December 31, 2011	18.9%	$0	$3,237,266,000	$8,281,000
December 31, 2012	18.9%	$0	$0	$8,509,000
December 31, 2013	18.9%	$0	$0	$8,743,000

The employer's current service cost in the above table was estimated based on projected members' pensionable earnings. The actual employer's current service cost will be different from these estimates and, as such, the contribution requirements should be monitored closely to ensure compliance with the ITA.

[3] Expressed as a percentage of members' pensionable earnings.

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Actuarial Opinion

In our opinion, for the purposes of the valuations,

- the membership data on which the valuation is based are sufficient and reliable
- the assumptions are appropriate
- the methods employed in the valuation are appropriate

This report has been prepared, and our opinions given, in accordance with accepted actuarial practice in Canada. It has also been prepared in accordance with the funding and solvency standards set by the Pension Benefits Act (Ontario).

Scott Clausen	M. Teresa Palandra
Fellow of the Society of Actuaries	Fellow of the Society of Actuaries
Fellow of the Canadian Institute of Actuaries	Fellow of the Canadian Institute of Actuaries
29 May 2012	29 May 2012
Date	Date

APPENDIX A

Prescribed Disclosure

Definitions

The Act defines a number of terms as follows:

Defined Term	Description	Result (in 000s)
Transfer Ratio	The ratio of: (a) solvency assets minus the lesser of the Prior Year Credit Balance and the minimum required employer contributions until the next required valuation; to (b) the sum of the solvency liabilities and liabilities for benefits, other than benefits payable under qualifying annuity contracts that were excluded in calculating the solvency liabilities.	0.58
Prior Year Credit Balance	Accumulated excess of contributions made to the pension plan in excess of the minimum required contributions (note: only applies if the Company chooses to treat the excess contributions as a Prior Year Credit Balance). Development summarized below.	$161,190
Solvency Assets	Market value of assets including accrued or receivable income and excluding the value of any qualifying annuity contracts.	$4,806,893
Solvency Asset Adjustment	The sum of:	
	(a) the difference between smoothed value of assets and the market value of assets	$368,700
	(b) the present value of any going concern special payments (including those identified in this report) within 5 years following the valuation date	$269,350
	(c) the present value of any previously scheduled solvency special payments (excluding those identified in this report)	$0
		$638,050
Solvency Liabilities	Liabilities determined as if the plan had been wound up on the valuation date, including liabilities for plant closure benefits or permanent layoff benefits that would be immediately payable if the employer's business were discontinued on the valuation date of the report, but, if elected by the plan sponsor, excluding liabilities for, (a) any escalated adjustment, (b) excluded plant closure benefits, (c) excluded permanent layoff benefits, (d) special allowances other than funded special allowances, (e) consent benefits other than funded consent benefits, (f) prospective benefit increases, (g) potential early retirement window benefit values, and (h) pension benefits and ancillary benefits payable under a qualifying annuity contract.	$5,633,679
Solvency Liability Adjustment	The amount by which solvency liabilities are adjusted as a result of using a solvency valuation interest rate that is the average of market interest rates calculated over the period of time used in the determination of the smoothed value of assets.	($626,531)

Defined Term	Description		Result (in 000s)
Solvency Deficiency	The amount, if any, by which the sum of:		
	(a)	the solvency liabilities	$5,633,679
	(b)	the solvency liability adjustment	($626,531)
	(c)	the prior year credit balance	$161,190
			$5,168,338
	Exceeds the sum of		
	(d)	the solvency assets net of termination expense provision	$4,795,159
	(e)	the solvency asset adjustment	$638,050
			$5,433,209
			$0

Timing of Next Required Valuation

In accordance with the *Act* the next valuation of the Plan would be required at an effective date within one year of the current valuation date if:

- The ratio of solvency assets to solvency liabilities is less than 80%.
- The ratio of solvency assets to solvency liabilities is less than 85% and solvency liabilities exceed solvency assets by $5 million or more.
- The employer elected to exclude plant closure or permanent lay-off benefits under Section 5(18) of the regulations, and has not rescinded that election.

Otherwise, the next valuation of the Plan would be required at an effective date no later than three years after the current valuation date.

Accordingly, the next valuation of the Plan will be required as of December 31, 2014.

Special Payments

Based on the results of this valuation, the Plan is not fully funded. In accordance with the Act, any going concern deficits must be amortized over a period not exceeding 15 years and any solvency deficits must be amortized over a period not exceeding 5 years.

As such, special payments must be made as follows:

Type of payment	Start date	End date	Monthly Special Payment	Present Value Going Concern Basis[4]	Present Value Solvency Basis[5]
Going concern	Dec. 31, 2003	Dec. 31, 2018	$1,397,417	$97,677,000	$75,689,000
Going concern	Dec. 31, 2006	Dec. 31, 2021	$595,637	$55,221,000	$32,262,000
Going concern	Dec. 31, 2009	Dec. 31, 2024	$2,038,594	$228,600,000	$110,417,000
				$381,498,000	
New going concern	Dec. 31, 2011	Dec. 31, 2026	$941,258	$116,206,000	$50,982,000
				$497,704,000	$269,350,000
Total			$4,972,906		

The present value of going concern special payments scheduled in the previous valuation is lower than the going concern shortfall resulting in a going concern unfunded liability of $116,206,000. As a result, a new going concern special payment schedule had to be established.

Pension Benefit Guarantee Fund (PBGF) Assessment

The PBGF assessment base and liabilities are derived as follows:

Solvency assets	$4,806,893	(a)
PBGF liabilities	$5,633,679	(b)
Solvency liabilities	$5,633,679	(c)
Ontario asset ratio	100%	(d) = (b) ÷ (c)
Ontario portion of the fund	$4,806,893	(e) = (a) x (d)
PBGF assessment base	$826,786	(f) = (b) – (e)
Amount of additional liability for plant closure and/or permanent layoff benefits which is not funded and subject to the 2% assessment pursuant to s.37(4)	$0	(g)

[4] Calculation only considers going concern special payments and is based on a going concern discount rate.

[5] Calculation considers both solvency and going concern special payments (five years only) and is based on the average solvency discount rate.

The PBGF assessment is calculated as follows:

$5 for each Ontario member	$64,775	(h)
0.5% of PBGF assessment base up to 10% of PBGF liabilities	$2,817,000	(i)
1.0% of PBGF assessment base between 10% and 20% of PBGF liabilities	$2,634,000	(j)
1.5% of PBGF assessment base over 20% of PBGF liabilities	$0	(k)
Sum of (h), (i), (j) and (k)	$5,515,775	(l)
$300 for each Ontario member	$3,886,500	(m)
Lesser of (l) and (m)	$3,886,500	(n)
2.0% of additional liabilities ((g) x 2%)	$0	(o)
Total Guarantee Fund Assessment ((n) + (o), no less than $250) (before applicable tax)	$3,886,500	(p)

Prior Year Credit Balance

The Prior Year Credit Balance was determined as follows:

Prior Year Credit Balance at previous valuation	$0	(a)
Actual employer contributions	$458,225,000	(b)
Required employer contributions	$297,035,000	(c)
Prior Year Credit Balance at current valuation	$161,190,000	(d) = (a) + (b) – (c)

APPENDIX B

Plan Assets

The pension fund is held in trust by CIBC Mellon and is invested in accordance with investment policy. In preparing this report, we have relied upon the auditors' report signed by KPMG and the fund statements prepared by CIBC Mellon.

Reconciliation of Market Value of Plan Assets

The pension fund transactions since the last valuation are summarized in the following table:

(in 000s)	2010	2011
January 1	$4,346,096	$4,708,666
PLUS		
Members' contributions	$23,784	$26,501
Company's contributions	$193,493	$151,542
Reciprocal transfers	$3,963	$4,008
Investment income	$420,835	$102,394
	$642,075	$284,445
LESS		
Pensions paid	$248,404	$255,676
Lump-sums paid	$16,367	$30,128
Administration and investment fees	$14,734	$13,603
	$279,505	$299,407
December 31	$4,708,666	$4,693,703
Gross rate of return[6]	9.7%	2.2%
Rate of return net of expenses[7]	9.4%	1.9%

The market value of assets shown in the above table is adjusted to reflect in-transit amounts as follows:

(in 000s)	Previous Valuation	Current Valuation
Market value of invested assets	$4,346,096	$4,693,703
In-transit amounts		
• Company contributions	$0	$113,190
• Transfers	$247	$0
Market value of assets adjusted for in-transit amounts	$4,346,343	$4,806,893

We have tested the pensions paid, the lump-sums paid and the contributions for consistency with the membership data for the Plan members who have received benefits or made contributions. The results of these tests were satisfactory.

[6] Assuming mid-period cash flows.

[7] Assuming mid-period cash flows.

Investment Policy

The plan administrator adopted a statement of investment policy and procedures. This policy is intended to provide guidelines for the manager(s) as to the level of risk which is commensurate with the Plan's investment objectives. A significant component of this investment policy is the asset mix.

The constraints on the asset mix and the actual asset mix at the valuation date are provided for information purposes:

	Investment Policy	Actual Asset Mix as at December 31, 2011
	Target	
Cash, cash equivalents, and short term securities	2%	4%
Fixed income	33%	36%
Canadian public equity	17%	18%
Foreign public equity	41%	39%
Private equity and hedge funds	2%	3%
Real estate and infrastructure	5%	0%
	100%	100%

Because of the mismatch between the Plan's assets (which are invested in accordance with the above investment policy) and the Plan's liabilities (which tend to behave like long bonds) the Plan's financial position will fluctuate over time. These fluctuations could be significant and could cause the Plan to become under, or over, funded even if the Company contributes to the Plan based on the funding requirements presented in this report.

APPENDIX C

Methods and Assumptions – Going Concern

Valuation of Assets

For this valuation, we have used an adjusted market-value method to determine the smoothed value of assets. Under this method, the difference between actual and expected equity performance during a given year are spread on a straight-line basis over 5 years in accordance with the schedule shown in the following table:

(in 000s)	2008	2009	2010	2011
Equity portion of assets at year-end	$2,414,263	$2,855,533	$2,944,478	$2,727,859
Rate of return earning on equities (reported by fund managers)	-27.77%	16.63%	9.37%	-4.45%
Change in CPI	1.20%	1.26%	2.42%	2.22%
Expected rate of return on equities (change in CPI + 6%)	7.20%	7.26%	8.42%	8.22%
Investment return loss/(gain) on equities	$982,994	($246,987)	($27,490)	$359,238
Carry forward of 2008 loss/(gain)	$786,395	$589,796	$393,198	$196,599
Carry forward of 2009 loss/(gain)		($197,590)	($148,192)	($98,795)
Carry forward of 2010 loss/(gain)			($21,992)	($16,494)
Carry forward of 2011 loss/(gain)				$287,390
Total adjustment to assets				$368,700

Accordingly, the smoothed value of assets as at December 31, 2011 is $5,062,403,000 (market value of $4,693,703,000 plus $368,700,000).

The asset values produced by this method are related to the market value of the assets, with the advantage that, over time, the market-related asset values will tend to be more stable than market values. To the extent that more equity investments outperform the CPI + 6% benchmark over the long term, the smoothed value will tend to be lower than the market value.

The smoothed value of assets shown above is adjusted to reflect in-transit amounts as follows:

(in 000s)	Previous Valuation	Current Valuation
Smoothed value of assets	$4,770,956	$5,062,403
In-transit amounts		
• Employer contributions	$0	$113,190
• Transfers	$247	$0
Smoothed value of assets, adjusted for in-transit amounts	$4,771,203	$5,175,593

Going Concern Funding Target

Over time, the real cost to the employer of a pension plan is the excess of benefits and expenses over member contributions and investment earnings. The actuarial cost method allocates this cost to annual time periods.

For purposes of the going concern valuation, we have continued to use the projected unit credit actuarial cost method. Under this method, we determine the present value of benefit cash flows expected to be paid in respect of service accrued prior to the valuation date, based on projected final average earnings. This is referred to as the funding target. For each individual plan member, accumulated contributions with interest are established as a minimum actuarial liability.

The funding excess or funding shortfall, as the case may be, is the difference between the market or smoothed value of assets and the funding target. A funding excess on a market value basis indicates that the current market value of assets and expected investment earnings are expected to be sufficient to meet the cash flows in respect of benefits accrued to the valuation date as well as expected expenses – assuming the plan is maintained indefinitely. A funding shortfall on a market value basis indicates the opposite – that the current market value of the assets is not expected to meet the plan's cash flow requirements in respect of accrued benefits and absent additional contributions.

As required under the Act, a funding shortfall must be amortized over no more than 15 years through special payments. A funding excess may, from an actuarial standpoint, be applied immediately to reduce required employer current service contributions unless precluded by the terms of the plan or by legislation.

The actuarial cost method used for the purposes of this valuation produces a reasonable matching of contributions with accruing benefits. Because benefits are recognized as they accrue, the actuarial cost method provides an effective funding target for a plan that is maintained indefinitely.

Current Service Cost

The current service cost is the present value of projected benefits to be paid under the plan with respect to service expected to accrue during the period until the next valuation.

The employer's current service cost is the total current service cost reduced by the members' required contributions.

The employer's current service cost has been expressed as a percentage of the members' pensionable earnings to provide an automatic adjustment in the event of fluctuations in membership and/or pensionable earnings.

Under the projected unit credit actuarial cost method, the current service cost for an individual member will increase each year as the member approaches retirement. However, the current service cost of the entire group, expressed as a percentage of the members' pensionable earnings, can be expected to remain stable as long as the average age of the group remains constant.

Actuarial Assumptions – Going Concern Basis

The present value of future benefit payment cash flows is based on economic and demographic assumptions. At each valuation we determine whether, in our opinion, the actuarial assumptions are still appropriate for the purposes of the valuation, and we revise them, if necessary. Emerging experience will result in gains or losses that will be revealed and considered in future actuarial valuations.

The table below shows the various assumptions used in the current valuation in comparison with those used in the previous valuation.

Assumption	Current valuation	Previous valuation
Discount rate:	5.50%	5.50%
Inflation:	2.25%	2.25%
ITA limit / YMPE increases:	3.25%	3.25%
Pensionable earnings increases:	2.75% + Merit	2.75% + Merit
Post retirement pension increases:	2.25%	2.25%
Interest on employee contributions:	2.00%	4.50%
Retirement rates:	Age related table	Age related table
Termination rates:	Age related table	Age related table
Mortality rates:	100% of the rates of the 1994 Uninsured Pensioner Mortality Table	100% of the rates of the 1994 Uninsured Pensioner Mortality Table
Mortality improvements:	Fully Generational	Fully Generational
Disability rates:	Age Related Table	Age Related Table
Eligible spouse at retirement:	80%	80%
Spousal age difference:	Male 3 years older	Male 3 years older

The assumptions are best-estimate with the exception that the discount rate includes a margin for adverse deviations, as shown below.

Age and Service Related Tables

Sample rates from the age and service related tables are summarized in the following table:

	Termination			Retirement		
					Reduction Eligible	
Age	**Males**	**Females**	**Disability**	**Unreduced**	**Male**	**Female**
15	4%	5%				
20	4%	5%	0.00%	15%	0%	0%
25	4%	5%	0.00%	15%	0%	0%
30	2%	4%	0.105%	15%	0%	0%
35	2%	4%	0.110%	15%	0%	0%
40	1%	3%	0.115%	15%	0%	0%
45	1%	3%	0.120%	15%	0%	0%
50	1%	3%	0.295%	15%	0%	0%
55	0%	0%	1.000%	15%	2%	5%
56	0%	0%	1.000%	25%	2%	5%
57	0%	0%	1.000%	25%	2%	5%
58	0%	0%	1.000%	25%	2%	5%
59	0%	0%	1.000%	25%	2%	5%
60	0%	0%	1.878%	25%	2%	5%
61	0%	0%	1.878%	25%	7%	10%
62	0%	0%	1.878%	25%	7%	10%
63	0%	0%	1.878%	25%	7%	10%
64	0%	0%	1.878%	25%	7%	10%
65	0%	0%	1.878%	100%	100%	100%

Pensionable Earnings

The benefits ultimately paid will depend on each member's final average earnings. To calculate the pension benefits payable upon retirement, death or termination of employment, we have taken 2011 pensionable earnings and assumed that such earnings will increase at 3.25% per year plus and age/service dependent merit factor described below.

	Salary increases due to movement within the salary structure*	
Age	**First 4 Years of Employment**	**Subsequent Years**
Under 25	7.0%	1.0%
25 – 29	3.0%	1.0%
30 – 34	3.5%	1.5%
35 – 39	3.5%	1.5%
40 – 44	3.5%	2.0%
45 – 49	3.5%	1.5%
50 – 54	2.0%	1.5%
55 – 59	2.0%	1.5%
60 & over	2.0%	0.0%

** Over and above any increase in salaries due to adjustments to the salary structure itself.*

Rationale for Assumptions

A rationale for each of the assumptions used in the current valuation is provided below.

Discount Rate

We have discounted the expected benefit payment cash flows using the expected investment return on the market value of the fund. Other bases for discounting the expected benefit payment cash flows may be appropriate, particularly for purposes other than those specifically identified in this valuation report.

The discount rate is comprised of the following:

- Estimated returns for each major asset class consistent with market conditions on the valuation date and the target asset mix specified in the Plan's investment policy
- Additional returns assumed to be achievable due to active equity management equal to the fees related to active equity management.
- Implicit provision for expenses determined as the average rate of expenses paid from the fund
- A margin for adverse deviations of 0.91%

The discount rate was developed as follows:

Assumed investment return	6.48%
Additional returns for active management	0.18%
Expense provision	(0.25%)
Margin for adverse deviation	(0.91%)
Net discount rate	5.50%

Explicit Expenses

$0 explicit expense

Inflation

The inflation assumption is based on market expectations of long-term inflation implied by the yields on nominal and real return bonds at the valuation date

Income Tax Act Pension Limit and Year's Maximum Pensionable Earnings
The assumption is based on historical real economic growth and the underlying inflation assumption.

Pensionable Earnings
The general wage growth component of this assumption is based on historical real economic growth, current market conditions and the underlying inflation assumption. The assumption for future merit and promotional increases over general wage growth is based on an experience study that was conducted in 2001 considering increases over the years 1998 to 2000.

Post Retirement Pension Increases
The assumption is based on the Plan formula and inflation assumption above.

Retirement Rates
The assumption is based on experience over the years 2000 to 2006. Subsequent experience has been consistent with these rates.

Termination Rates
The assumption is based on experience from 2000 to 2006. Subsequent experience has been consistent with these rates. For employees who terminate and will qualify for an unreduced pension or have 25 or more years of continuous service, the value includes the member's right to subsidized reductions if the pension commences before age 65 (age 60 for females hired before 1976).

Mortality Rates
There is no reason to expect the mortality to differ from the 1994 Uninsured Pensioners mortality table. Furthermore, there is strong evidence of continuing improvement in mortality since 1994 and it has become an industry standard to assume this trend continues into the future. We have used the AA projection scale to allow for improvements in mortality since 1994 up to 2012 and applied on a generational basis thereafter Based on to the assumption used, the life expectancy of a member age 65 at the valuation date is 19.7 years for males and 22.1 years for females. Recent experience has been consistent with the assumptions.

Interest on Employee Contributions
The assumption is based on Plan terms and the underlying investment return assumption.

Disability Rates
Use of a different assumption would not have a material impact on the valuation.

Eligible Spouse
The assumption is based on an industry standard for non-retired members (actual status used for retirees).

Spousal Age Difference
The assumption is based on an industry standard showing males are typically 4 years older than their spouse.

APPENDIX D

Methods and Assumptions – Hypothetical Wind-up and Solvency

Hypothetical Wind-up Basis

The Canadian Institute of Actuaries requires actuaries to report the financial position of a pension plan on the assumption that the plan is wound-up on the effective date of the valuation, with benefits determined on the assumption that the pension plan has neither a surplus nor a deficit. For the purposes of the hypothetical wind-up valuation, the plan wind-up is assumed to occur in circumstances that maximize the actuarial liability.

To determine the actuarial liability on the hypothetical wind-up basis, we have valued those benefits that would have been paid had the Plan been wound up on the valuation date, including benefits that would be immediately payable if the employer's business were discontinued on the valuation date, with all members fully vested in their accrued benefits.

The circumstances in which the plan wind-up is assumed to have taken place are as follows: unilateral termination of the plan. To determine the solvency actuarial liability, the cost of future indexing as been excluded from the solvency liabilities as permitted under the *Pension Benefits Act* (Ontario).

Upon plan wind-up members are given options for the method of settling their benefit entitlements. The options vary by eligibility and by province of employment, but in general, involve either a lump sum transfer or an immediate or deferred pension.

The value of benefits assumed to be settled through a lump sum transfer is based on the assumptions described in Section 3500 – *Pension Commuted Values* of the Canadian Institute of Actuaries' Standards of Practice applicable for December 31, 2011.

Benefits provided as an immediate or deferred pension are assumed to be settled through the purchase of annuities based on an estimate of the cost of purchasing annuities.

However, it may not be possible to settle the liabilities through the purchase of annuities due to the size of the Plan and the limited annuity market in Canada. In accordance with the *Canadian Institute of Actuaries Educational Note: Assumptions for Hypothetical Wind-up and Solvency Valuations with Effective Dates Between December 31, 2011 and December 30, 2012,* we have assumed that the settlement of such liabilities would be priced on the same basis as the smaller group annuities that are available in the market.

There is limited data available to provide credible guidance on the cost of a purchase of indexed annuities in Canada. In accordance with the *Canadian Institute of Actuaries Educational Note: Assumptions for Hypothetical Wind-up and Solvency Valuations with Effective Dates Between December 31, 2011 and December 30, 2012,* we have assumed that an appropriate proxy for estimating the cost of such purchase is using the yield on the long-term Government of Canada Real Return bonds.

We have not included a margin for adverse deviation in the solvency and hypothetical wind-up valuations.

The assumptions are as follows:

Form of Benefit Settlement Elected by Member	
Lump sum	70% of active members under age 55 and 40% of active members over age 55 elect to receive their benefit entitlement in a lump sum
Annuity purchase	All remaining members are assumed to elect to receive their benefit entitlement in the form of a deferred or immediate pension. These benefits are assumed to be settled through the purchase of deferred or immediate annuities from a life insurance company.
Basis for Benefits Assumed to be Settled through a Lump Sum	
Mortality rates:	U94 Generational
Interest rate (for solvency calculations):	3.74% per year for 10 years, 5.04% per year thereafter
Interest rate (for wind-up calculations):	2.60% per year for 10 years, 4.10% per year thereafter (non-indexed rates); and 1.30% per year for 10 years, 1.60% per year thereafter (indexed rates) *New Society and Management Members:* 2.60% per year for 10 years, 4.10% per year thereafter (non-indexed rates); and 1.60% per year for 10 years, 2.20% per year thereafter (indexed rates)
Basis for Benefits Assumed to be Settled through the Purchase of an Annuity	
Mortality rates:	U94 Generational
Interest rate (for solvency calculations):	4.30% per year
Interest rate (for wind-up calculations):	3.31% per year (non-indexed rates); 0.45% per year (indexed rates) *New Society and Management Members:* 3.31% per year (non-indexed rates); and 0.78% per year for 10 years, 1.06% per year thereafter (indexed rates)
Retirement Age	
Maximum value:	Members are assumed to retire at the age which maximizes the value of their entitlement from the Plan based on the eligibility requirements which have been met at the valuation date
Grow-in:	The benefit entitlement and assumed retirement age of Ontario members whose age plus service equals at least 55 at the valuation date, reflect their entitlement to grow into early retirement subsidies

Other Assumptions	
Final average earnings:	Based on actual pensionable earnings over the averaging period
Family composition:	Same as for going concern valuation
Maximum pension limit:	$2,646.67 increasing at 2.31% per year for 10 years, 3.44% per year thereafter
Termination expenses:	0.25% of assets

To determine the hypothetical wind-up position of the Plan, a provision has been made for estimated termination expenses payable from the Plan's assets in respect of actuarial and administration expenses that may reasonably be expected to be incurred in terminating the Plan and to be charged to the Plan.

In addition, termination expenses also include a provision for transaction fees related to the liquidation of the Plan's assets and for the reduction in the value of the Plan's equity assets resulting from their liquidation. Such fees and liquidation impact are difficult to assess and will vary depending on the nature of the assets held and market conditions at the time assets are liquidated.

Because the settlement of all benefits on wind-up is assumed to occur on the valuation date and is assumed to be uncontested, the provision for termination expenses does not include custodial, investment management, auditing, consulting and legal expenses that would be incurred between the wind-up date and the settlement date or due to the terms of a wind-up being contested. Expenses associated with the distribution of any surplus assets that might arise on an actual wind-up are also not included in the estimated termination expense provisions.

In determining the provision for termination expenses payable from the Plan's assets, we have assumed that the plan sponsor would be solvent on the wind-up date. We have also assumed, without analysis, that the Plan's terms as well as applicable legislation and court decisions would permit the relevant expenses to be paid from the Plan.

Actual fees incurred on an actual plan wind-up may differ materially from the estimates disclosed in this report.

Incremental Cost

In order to determine the incremental cost, we estimate the hypothetical wind-up liabilities at the next valuation date. We have assumed that the cost of settling benefits by way of a lump sum or purchasing annuities remains consistent with the assumptions described above. Since the projected hypothetical wind-up liabilities will depend on the membership in the Plan at the next valuation date, we must make assumptions about how the Plan membership will evolve over the period until the next valuation.

We have assumed that the Plan membership will evolve in a manner consistent with the going concern assumptions as follows:

- Members terminate, retire and die consistent with the termination, retirement and mortality rates used for the going concern valuation.
- Pensionable earnings, the Income Tax Act pension limit and the Year's Maximum Pensionable Earnings increase in accordance with the related going concern assumptions.
- Active members accrue pensionable service in accordance with the terms of the Plan.
- To accommodate for new entrants to the Plan, we have added to the projected liability an amount based on the liability of new entrants that have joined the Plan since the previous valuation.
- Cost of living adjustments are consistent with the inflation assumption used for the going concern valuation.

Solvency Basis

In determining the financial position of the Plan on the solvency basis, we have used the same assumptions and methodology as were used for determining the financial position of the Plan on the hypothetical wind-up basis, except for the differences in assumptions described above.

The solvency position is determined in accordance with the requirements of the Act.

APPENDIX E

Membership Data

Analysis of Membership Data

The actuarial valuation is based on membership data as at December 31, 2011, provided by Hydro One Inc.

We have applied tests for internal consistency, as well as for consistency with the data used for the previous valuation. These tests were applied to membership reconciliation, basic information (date of birth, date of hire, date of membership, gender, etc.), pensionable earnings, credited service, contributions accumulated with interest and pensions to retirees and other members entitled to a deferred pension. Contributions, lump sum payments and pensions to retirees were compared with corresponding amounts reported in financial statements. The results of these tests were satisfactory.

Plan membership data are summarized below. For comparison, we have also summarized corresponding data from the previous valuation.

	31.12.11	31.12.09
Active Members		
Number	5,446	5,042
Total pensionable earnings for the following year	$493,804,272	$435,017,627
Average pensionable earnings for the following year	$90,673	$86,279
Average years of pensionable service	13.9	14.8
Average age	44.2	44.8
Accumulated contributions with interest	$350,040,313	$334,148,262
Members on Long Term Disability		
Number	130	125
Total pensionable earnings for the following year	$9,669,278	$8,808,644
Average pensionable earnings for the following year	$74,379	$70,469
Average years of pensionable service	24.6	25.2
Average age	55.4	55.2
Accumulated contributions with interest	$9,231,515	$9,126,864
Deferred Pensioners		
Number	299	320
Total annual pension	$3,223,848	$3,565,653
Average annual pension	$10,782	$11,143
Average age	52.6	52.0
Pensioners and Survivors		
Number	5,304	5,265
Total annual lifetime pension	$199,441,218	$184,259,583
Total annual temporary pension	$25,244,104	$25,090,168
Average annual lifetime pension	$37,602	$34,997
Average age	71.0	70.4
Pensioners and Survivors		
Number	1,776	1,819
Total annual lifetime pension	$41,307,153	$37,199,616
Total annual temporary pension	$567,542	$557,903
Average annual lifetime pension	$23,259	$20,451
Average age	79.6	78.3

The membership movement for all categories of membership since the previous actuarial valuation is as follows:

	Actives	Long Term Disabilities	Deferred Vested	Pensioners	Survivors	Total
Total at 12.31.2009	5,042	125	320	5,265	1,819	12,571
New entrants	792	2				794
Actives to LTD	(21)	21				0
LTD to actives	2	(2)				0
Terminations:						0
• transfers/ lump sums	(33)	0	(9)			(42)
• deferred pensions	(26)	0	26			0
• reciprocal completed	(3)					(3)
Deaths	(20)	(1)	(1)	(298)		(320)
Retirements	(287)	(15)	(37)	339		0
Beneficiaries					168	168
Benefits Expired	0	0	0	(2)	(211)	(213)
Total at 12.31.2011	5,446	130	299	5,304	1,776	12,955

The distribution of the active members by age and pensionable service as at the valuation date is summarized as follows:

	Years of Pensionable Service							
Age	**0-4**	**5-9**	**10-14**	**15-19**	**20-24**	**25-29**	**30 +**	**Total**
Under 25	89	1						90
	$67,198	*						$67,219
25 to 29	640	71						711
	$74,538	$85,163						$75,599
30 to 34	358	234	25					617
	$78,717	$87,303	$92,286					$82,523
35 to 39	221	175	68					464
	$83,728	$87,584	$93,907					$86,674
40 to 44	191	127	44	20	99	3		484
	$87,326	$97,027	$97,626	$89,937	$91,566	*		$91,828
45 to 49	166	105	94	23	359	240	23	1,010
	$86,793	$93,384	$92,418	$97,790	$95,369	$92,735	$100,098	$93,016
50 to 54	121	83	85	14	201	265	364	1,133
	$90,437	$91,976	$98,472	$98,471	$93,948	$95,350	$99,716	$96,005
55 to 59	64	48	60	14	86	110	320	702
	$90,254	$91,561	$94,603	$109,499	$93,755	$94,508	$102,475	$97,766
60 to 64	25	22	23	6	42	39	139	296
	$106,534	$99,304	$100,846	$113,676	$99,340	$93,695	$102,363	$101,028
65 +	9	7	15	2	12	9	15	69
	$90,817	$95,773	$109,138	*	$94,742	$90,858	$102,871	$99,123
Total	1,884	873	414	79	799	666	714	5,576
	$80,497	$90,359	$95,842	$99,475	$94,566	$94,108	$102,568	$90,293

* Data for cells with three or fewer members have been suppressed to preserve confidentiality of information.

The distribution of the inactive members by age as at the valuation date is summarized as follows:

	Deferred Pensioners		Pensioners		Survivors	
Age	**Number**	**Average Pension**	**Number**	**Average Pension**	**Number**	**Average Pension**
<45	31	$8,845			5	$14,235
45 - 49	49	$8,039			7	$16,209
50 - 54	93	$11,213	66	$44,807	21	$18,130
55 - 59	85	$12,983	520	$43,205	60	$19,212
60 - 64	38	$10,531	1,094	$39,507	82	$20,835
65 - 69	3	$3,075	985	$37,558	112	$25,972
70 - 74			706	$35,566	150	$24,132
75 - 79			701	$34,740	283	$23,279
80 - 84			706	$36,871	461	$24,857
85 - 89			370	$35,794	352	$23,002
90 - 94			129	$34,686	193	$22,333
95 +			27	$21,924	50	$17,959
Total	299	$10,782	5,304	$37,602	1,776	$23,259

APPENDIX F

Summary of Plan Provisions

This valuation is based on the plan provisions in effect on December 31, 2011.

The following is a summary of the main provisions of the Plan in effect on December 31, 2011. This summary is not intended as a complete description of the Plan.

Eligibility for membership	The following categories of employees are members of the Plan: • All regular employees • Employees for whom the Office and Professional Employees International Union was the bargaining agent prior to July 30, 1982. • Employees who became continuing construction clerical employees after July 29, 1982 and before August 8, 1984. • Employees who have completed three months of continuous employment as a probationary employee Any other employee, with the exception of construction trades, machinists, and hotel and restaurant employees, who has completed twenty-four months of continuous employment and who has at least 700 hours of employment or earnings of 35% of the YMPE (see note on next page) in each of the two previous calendar years, may elect to become a member of the Plan. Other members include pensioners, terminated employees with deferred pensions, and employees receiving long term disability benefits. **Note:** "YMPE" is the Year's Maximum Pensionable Earnings as defined under the Canada Pension Plan.
Employee Contributions	The employees contribute at the following rates until they complete 35 years of credited service: <u>Power Workers Union members</u> • 4.5% of base annual earnings up to the YMPE, • And 6.5% of base annual earnings in excess of the YMPE. <u>Management and Society members</u> • 4.0% of base annual earnings up to the YMPE, • And 6.0% of base annual earnings in excess of the YMPE. Society members are required to contribute an additional 0.5% of base annual earnings when the ratio of solvency assets to solvency liabilities is less than 106%.

Retirement Dates

Normal Retirement Date

- Female members whose continuous employment commenced prior to January 1, 1976:
  The first day of the month when she in fact retires, coincident with or next following the attainment of age 60 or any subsequent month up to the month coincident with or next following her sixty-fifth birthday.
- All other members:
  The first day of the month coincident with or next following the attainment of age 65.

Early Retirement Date

- An employee may retire prior to the normal retirement date without any reduction in the accrued pension, if the sum of the employee's age and years of continuous employment is equal to or greater than 82 (for management employees hired on or after January 1, 2004 and Society employees hired on or after November 17, 2005, if the sum of the employee's age and years of credited service is equal to or greater than 85).
- A female employee whose continuous employment commenced prior to 1976 with at least 15 years of continuous employment, or any other employee with 15 or more years of continuous employment but less than 25 years of continuous employment, who does not qualify for any of the previously mentioned early retirement provisions, may retire within 10 years of normal retirement date. In such a case the employee's accrued pension is reduced by 2% for each year up to five years and 3% for each additional year by which the early retirement date precedes the employee's normal retirement date.
- Otherwise, an employee may retire prior to age 60 with 25 or more years of continuous employment, but within 10 years of normal retirement date. In such a case, the employee's accrued pension is reduced by 3% for each year by which early retirement precedes age 60.
- An employee, who does not qualify under any of the previously mentioned early retirement provisions and who has at least two years of Plan membership, may retire within 10 years of normal retirement date. In such a case, the pension is the actuarial equivalent of the member's deferred pension.
- A terminated employee with a deferred pension may retire under any of the previously mentioned provisions for early retirement without reduction provided that such provision was in effect on the date of termination.
- A terminated employee with a deferred pension, who terminated after March 31, 1986, with 25 or more years of continuous employment has the same early retirement provisions as those in effect for active employees at the date of termination.
- Otherwise, a terminated employee with a deferred pension, who terminated with 15 or more years of continuous employment, or who terminated with 2 or more years of Plan membership after 1987, may receive a pension within 10 years of normal retirement in accordance with the rules in effect on the date of termination. In such a case, the pension is the actuarial equivalent of the member's deferred pension.

Normal Retirement Pension	(a) 2% of the member's "high three-year average" (high five-year average for management employees hired on or after January 1, 2004 and Society employees hired on or after November 17, 2005) (see note below) for each year of credited service, subject to a maximum of 35 years LESS (b) 0.625% of the member's "high five-year average" up to the "average YMPE" (see note below) for each year of credited service included in (a) above subsequent to December 31, 1965. This factor has been reduced from 0.625% to 0.50% for members of the Power Workers Union (PWU) and for Society members hired prior to November 17, 2005.
Bridge Pension	For everyone except management employees hired on or after January 1, 2004 and Society members hires on or after November 17, 2005, 0.625% of the member's "high five-year average" up to the "average YMPE" (see note below) for each year of credited service included in (a) above, subject to a maximum of 30 years, multiplied by 35, and divided by 30. The bridge benefit is payable in the same form as the lifetime pension, until the member attains age 65. Management employees hired on or after January 1, 2004 and Society members hired after November 17, 2005 are not entitled to receive a bridge benefit from the Plan. **Note:** "High three-year average" is the average of the member's base annual earnings plus bonuses up to a set percentage during the thirty-six consecutive months when the base earnings were highest. For earnings after 1999, the percentage of bonus under the performance achievement plan included in pensionable earnings is 50%. The "average YMPE" is the average of the YMPEs during the sixty consecutive months when the base earnings were highest.
Pension Increases	Pension increases of 100% (75% for management employees hired on or after January 1, 2004 and Society employees hired after November 17, 2005) of the increase in the CPI (Ontario) will be given every January 1 to pensioners, beneficiaries and terminated employees with deferred pensions.
Maximum Pension	The benefits in respect of continuous employment after 1991 are limited to the maximum allowable under the Income Tax Act.

Death benefits	Pre-retirement: (a) Benefits in respect of Continuous Employment Prior to 1987 (i) If the member has completed 10 years of continuous employment, the surviving spouse or dependent child is entitled to a survivor's pension. The survivor's pension is an amount equal to 66.67% of the pension to which the member would have been entitled had the member retired on the date of death with no reduction for early retirement. The survivor's pension is payable to the surviving spouse until death or, if there is no eligible spouse, to the dependent children until age 18 (longer if disabled or in full-time attendance at a school or university). The total benefits paid are subject to a minimum of the member's contributions with interest. (ii) Otherwise, a payment of the member's contributions with interest is made to the beneficiary or estate. (b) Benefits in respect of Continuous Employment After 1986 (i) If the member has less than 2 years of Plan membership and has not completed 10 years of continuous employment, a payment of the member's contributions with interest is made to the beneficiary or estate. (ii) If the member has less than 2 years of Plan membership, but has completed 10 years of continuous employment, the surviving spouse is entitled to a survivor's pension as described in (a)(i) above. (iii) If the member has at least 2 years of Plan membership, but has not completed 10 years of continuous employment, the surviving spouse is entitled to receive the commuted value of the member's deferred pension. In lieu of such payment, the surviving spouse may elect to receive an immediate or deferred pension of equivalent commuted value. If there is no surviving spouse, a payment of the commuted value of the member's deferred pension is made to the beneficiary or estate. (iv) If the member has at least 2 years of Plan membership and has completed 10 years of continuous employment, the surviving spouse is entitled to the greater of an immediate pension of 66.67% of the pension to which the member would have been entitled had the member retired on the date of death with no reduction for early retirement, or an immediate pension with commuted value equivalent to the commuted value of the member's deferred pension. In lieu of this pension, the surviving spouse may elect to receive the commuted value of the member's deferred pension or a deferred pension of equivalent commuted value. If there is no surviving spouse, the dependent children are entitled to a pension of 66.67% of the pension to which the member would have been entitled had the member retired on the date of death with no reduction for early retirement, payable to age 18 (longer if disabled or in full-time attendance at a school or university). If there is no surviving spouse, a payment of the commuted value of the member's deferred pension less the commuted value of the pension payable to any dependent children is made to the beneficiary or estate.
Death benefits	Post retirement: • A survivor's pension, an amount equal to 66.67% of the pension to which the member would have been entitled, is payable on death after retirement to the surviving spouse or dependent children, subject to other options chosen at the time of retirement.

Termination Benefits	(a) Benefits in respect of Continuous Employment Prior to 1987 (i) The member is entitled to a refund of all of the member's pre-1987 contributions with interest, subject to (iv) below. (ii) A member, who has at least one year of Plan membership, may elect to receive, in lieu of (i) above, the pension accrued prior to 1987 commencing at normal or early retirement age ascertained in accordance with the rules pertaining to terminated employees with deferred pensions in effect upon termination of employment. (iii) A member, who has at least 10 years of Plan membership, may elect to receive, in lieu of (i) or (ii) above, a cash payment of 25% of the commuted value of the pension accrued prior to 1987, with 75% of such pension being paid at normal or early retirement age ascertained in accordance with the rules pertaining to terminated employees with deferred pensions in effect upon termination of employment. (iv) A member, who has both attained age 45 and completed 10 or more years of continuous employment, may not elect to receive a refund of contributions in respect of service between January 1, 1965 and December 31, 1986. The member may, however, elect to receive, in lieu of (ii) or (iii) above, a refund of the member's contributions to the Fund prior to 1965 together with credited interest plus 25% of the commuted value of the pension accrued after 1964 but prior to 1987, with entitlement to 75% of such pension being paid commencing on the normal or early retirement date ascertained in accordance with the rules pertaining to terminated employees with deferred pensions in effect upon termination of employment. The member may elect to transfer (see note below) the greater of the commuted value of the 75% pension or 75% of the member" contributions with interest made after 1964 but prior to 1987. (b) Benefits in respect of Continuous Employment After 1986 (i) A member is entitled to a refund of the member's post-1986 contributions with interest, subject to (iii) below. (ii) A member, who has at least one year of Plan membership, may elect to receive, in lieu of (i) above, the pension accrued after 1986 commencing at normal or early retirement age ascertained in accordance with the rules pertaining to terminated employees with deferred pensions in effect upon termination of employment. (iii) A member, who has at least two years of Plan membership, may not elect to receive a refund under (i) above. The member may, however, elect, in lieu of (ii) above, to transfer (see note below) the commuted value of the deferred pension. Note: Amounts must be transferred to a pension fund related to another pension plan, a prescribed retirement savings arrangement, or a life annuity which does not commence before the earliest date on which the member would have been entitled to retire.
Disability Benefits	A totally disabled employee receives benefits from an income replacement plan and ceases to contribute to the Pension Fund, but continues to accrue credited service. For this member, the base annual earnings for pension purposes are deemed to be increased by the same percentage increases described for pensions above.

Excess Contributions	Upon the earliest of termination of employment, death or retirement, the amount by which the member's post-1986 contributions with interest exceed 50% of the commuted value of the deferred pension accrued after 1986 is refunded to the member (to the spouse, beneficiary or estate, in the case of death). Upon termination of employment, if a member who has attained age 45 and completed 10 or more years of continuous employment elects to fully divest the pension accrued prior to 1987, the member is entitled to receive the amount by which the contributions with interest made after 1964 but prior to 1987 exceeds the commuted value of the pension accrued after 1964 but prior to 1987.

APPENDIX G

Employer Certification

With respect to the Report on the Actuarial Valuation for Funding Purposes as at December 31, 2011, of the Hydro One Pension Plan I hereby certify that, to the best of my knowledge and belief:

- The valuation reflects the terms of the Company's engagement with the actuary, particularly the requirement to include a margin of 0.91% in the discount rate used to perform the going concern valuation.
- The valuation reflects the Company's decisions in regards to determining the solvency funding requirements.
- A copy of the official plan documents and of all amendments made up to December 31, 2011 were provided to the actuary and is reflected appropriately in the summary of plan provisions contained herein.
- The asset information summarised in Appendix B is reflective of the Plan's assets.
- The membership data provided to the actuary included a complete and accurate description of every person who is entitled to benefits under the terms of the Plan for service up to December 31, 2011.

All events subsequent to December 31, 2011 that may have an impact on the Plan have been communicated to the actuary.

MAY 25/12
Date

Signed

SANDY STRUTHERS
Name

MERCER

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Vulnerable Energy Consumers Coalition (VECC)INTERROGATORY #32 List 1

Issue 7 **Are the 2013/14 Human Resources related costs (wages, salaries, benefits, incentive payments, labour productivity and pension costs) including employee levels appropriate? Has Hydro One demonstrated improvements in efficiency and value for dollar associated with its compensation costs?**

Interrogatory

Reference: Exhibit A, Tab 15, Schedule 1, page 5 and ExhibitA-13-1, Appendix A, page 3

Preamble: The pre-filed evidence indicates that as of March 31, 2011, there were 710 MCP staff for whom Senior Management at Hydro One has provided base pay annual escalators of 3.0% for 2012 and for each year 2013-2016.

a) Please provide an update to the current number of MCP staff and the forecasted number of MCP staff for 2013 and for 2014.

b) What would be the annual savings in 2012, 2013, and in 2014, if MCP employees had their base pay escalated by 2% for each year 2012-2014?

Response

The pre-filed evidence indicating that as of March 31, 2011 there were 710 MCP staff is an error. It should read 621 regular MCP staff.

a) As of June 30, 2012, there were 642 regular MCP employees. The forecasted number of regular MCP employees in 2013 and 2014 is 656 and 655 respectively.

b) If MCP employees had their base pay escalated by 2% per year from 2012-14, the estimated annual savings would be $0.20M, $0.21M, and $0.21M in OM&A and $0.25M, $0.25M, and $0.26M in Capex in 2012, 2013 and 2014 respectively.

Power Workers Union (PWU) INTERROGATORY #17 List 1

Issue 7 **Are the 2013/14 Human Resources related costs (wages, salaries, benefits, incentive payments, labour productivity and pension costs) including employee levels appropriate? Has Hydro One demonstrated improvements in efficiency and value for dollar associated with its compensation costs?**

Interrogatory

Ref (1): Exhibit C1/Tab 5/Sch 1/Page 1 of 12/Lines 5-9

> **Hydro One faces the prospect of unprecedented challenges in the years ahead associated with the availability of skilled and professional staff to operate, sustain and develop its transmission and distribution systems. Hydro One's greatest corporate risk with respect to its human resources continues to be an aging workforce and, with a world-wide scarcity of core skills in the electricity industry, a highly competitive labour market.**

Ref (2): Exhibit C1/Tab 5/Sch 1/Page 2 of 12/Lines 9-23

> **By December 31, 2011, approximately 1,150 Networks staff (transmission and distribution) were eligible for an undiscounted retirement. By December 31, 2013, approximately 1,460 Networks staff will be eligible for an undiscounted retirement. This number increases to approximately 1,633 by year end 2014. Hydro One is seeing a larger uptake in actual retirements. In 2009, 105 employees retired while in 2010, 137 employees retired. In 2011, 166 employees retired. This represents an increase of approximately 58% over the retirement uptake in 2009. To place this into context, between 2009 and 2011 cumulatively roughly 10% of the employees who were on staff at the start of 2009 have retired. This is a trend which is expected to continue through the next decade and is consistent with challenges faced by other utilities in the electricity sector throughout the world. Recent studies suggest that up to half the workforce in the North American electricity industry will be eligible for retirement in the next five years. Furthermore, it is anticipated that a greater number of staff eligible to retire will elect to retire sooner given the increased competition for these scarce resources in the marketplace.**

a) Please describe the challenges facing Hydro One in sustaining productivity gains in the coming years given the bow wave of retirements of experienced workforce and its replacement with increased levels of new staff? What training and staff development strategies and plans are in place to offset the "learners"' lower productivity in their first few years?

Response

The workforce renewal caused by senior employees leaving and being replaced by newer employees is both a challenge and an opportunity. While newer staff will not be necessarily as productive as seasoned and experienced employees, Hydro One is leveraging this opportunity by:

- Seeking different skill mixes when recruiting new employees
- Improving the selection process by adopting behavioral assessment tools to maximize the hiring of the best applicant
- Transferring skills and knowledge from senior to more junior employees
- Implementing different work methods
- Training new staff on new replacement core business processes and IT systems
- Continued use of university and college co-op's
- Additional non-technical training for new grads
- Renewed focus on managerial training ie. the Craft of Management

School Energy Coalition (SEC)INTERROGATORY #20 List 1

Issue 7 **Are the 2013/14 Human Resources related costs (wages, salaries, benefits, incentive payments, labour productivity and pension costs) including employee levels appropriate? Has Hydro One demonstrated improvements in efficiency and value for dollar associated with its compensation costs?**

Interrogatory

With respect to staffing:

a. Please provide a chart showing, on an annual basis from 2006 through 2014, the number of new hires in each major job category, the number of retirements in that category, and the number of voluntary or involuntary non-retirement departures on that category.
b. Please provide the most recent report to the board or any committee of the Board with respect to any human resources challenges.
c. If there are any plans in place to deal with any of those human resources challenges, please provide a copy.

Response

a)

New Hires, Retirements and Termination by Major PWU Job Categories 2006-2012

	Area Distribution Engineering Technician	Controller	Protection and Control Technician	Regional Maintainer - Forestry	Regional Maintainer - Electrical	Regional Maintainer - Lines
2006						
New Hires	7	3	0	10	18	3
Retirement	2	0	1	4	2	6
Termination (Voluntary & Involuntary)	2	0	0	1	1	7
2007						
New Hires	19	5	0	45	29	102
Retirement	7	2	1	5	5	11
Termination (Voluntary & Involuntary)	3	1	0	2	2	14
2008						
New Hires	17	0	4	0	1	2
Retirement	7	4	4	3	1	20
Termination (Voluntary & Involuntary)	4	1	0	1	2	7
2009						
New Hires	27	15	10	23	14	47
Retirement	3	2	1	8	4	25
Termination (Voluntary & Involuntary)	3	0	0	2	2	5
2010						
New Hires	14	0	13	33	2	49
Retirement	5	2	2	8	1	28
Termination (Voluntary & Involuntary)	1	2	0	1	0	2
2011						
New Hires	0	9	7	26	1	76
Retirement	5	3	3	9	8	24
Termination (Voluntary & Involuntary)	3	1	0	1	1	5

	Area Distribution Engineering Technician	Controller	Protection and Control Technician	Regional Maintainer - Forestry	Regional Maintainer - Electrical	Regional Maintainer - Lines
2012 – June Month End						
New Hires	0	0	2	24	0	50
Retirement	2	0	1	0	2	16
Termination (Voluntary & Involuntary)	1	0	0	0	1	2

*This report reflects regular employees only and does not include Hiring Hall Apprentices

New Hires, Retirements and Termination by Society Grades 2006-2012

	MP2	MP3	MP4	MP5	MP6	
2006						Total
New Hires	0	0	0	0	0	0
Retirement	0	1	4	4	2	11
Termination (Voluntary & Involuntary)	6	3	5	4	0	18
2007						Total
New Hires	4	1	14	4	0	23
Retirement	0	3	3	6	2	14
Termination (Voluntary & Involuntary)	3	1	8	11	0	23
2008						Total
New Hires	66	3	21	4	0	94
Retirement	1	3	9	12	2	27
Termination (Voluntary & Involuntary)	15	0	2	3	0	20
2009						Total
New Hires	49	4	25	2	0	80
Retirement	1	1	5	5	0	12
Termination (Voluntary & Involuntary)	9	0	7	4	0	20
2010						Total
New Hires	92	10	26	3	0	131
Retirement	1	2	11	3	2	19
Termination (Voluntary & Involuntary)	7	2	7	0	0	16
2011						Total
New Hires	38	1	3	2	0	44
Retirement	1	1	7	9	0	18
Termination (Voluntary & Involuntary)	10	1	3	1	0	15
2012 – June Month End						Total
New Hires	23	0	4	1	0	28
Retirement	0	1	6	9	0	16
Termination (Voluntary & Involuntary)	3	1	2	1	0	7

b) There have been no recent reports to the Board or subcommittee of the Board with respect to human resources challenges. The Human Resources Committee continues to be actively involved in a number of human resource issues and receive updates on a regular basis.

c) The plans to deal with human resources challenges are contained throughout the evidence within C1, Tab 5, Schedule 1 and C1, Tab 5, Schedule 2.

School Energy Coalition (SEC)INTERROGATORY #21 List 1

Issues 7 **Are the 2013/14 Human Resources related costs (wages, salaries, benefits, incentive payments, labour productivity and pension costs) including employee levels appropriate? Has Hydro One demonstrated improvements in efficiency and value for dollar associated with its compensation costs?**

Interrogatory

[C1-5-2/p.11]
Please provide a copy of each "collective agreement, midterm agreement and letter of understandings that bind the company".

Response

Please find attached electronic copies of the following attachments on the link below.
http://www.hydroone.com/RegulatoryAffairs/Pages/2013-2014Tx.aspx

Attachment 1: Hydro One-PWU Collective Agreement

Attachment 2: Hydro One – Society Collective Agreement

Attachment 3: One – CUSW Collective A

Attachment 4: A listing of the PWU mid-terms and Society Letters of Understanding

Attachment 5: A listing of the EPSCA agreements to which Hydro One is bound

School Energy Coalition (SEC)INTERROGATORY #22 List 1

Issue 7 **Are the 2013/14 Human Resources related costs (wages, salaries, benefits, incentive payments, labour productivity and pension costs) including employee levels appropriate? Has Hydro One demonstrated improvements in efficiency and value for dollar associated with its compensation costs?**

Interrogatory

[C1-5-2]
Please provide a breakdown by business unit and job category, of the additional employees for each year between 2010 and 2014.

Response

YEAR	JOB CATEGORY	LOB	# HIRED
2010	Administrative Assistant	ASSET MGMT	1
	Assistant Network Mgmt Eng/Off	ASSET MGMT	4
	Business Analyst	ASSET MGMT	3
	Mgr Conservation Demand Mgmt	ASSET MGMT	1
	Network Mgmt Eng/Off	ASSET MGMT	1
	Senior Conservation Analyst	ASSET MGMT	3
	Generation Connection Coord	ASSET MGMT	1
	Telecommunications Eng/Offr	ASSET MGMT	1
	Sustainment Manager	ASSET MGMT	1
	New Grad	ASSET MGMT	5
	Facility Contract Analyst	CORP+REG AFF	1
	Facility Officer	CORP+REG AFF	1
	Facility Planner/Scheduler	CORP+REG AFF	1
	On Line Communications Coodr	CORP+REG AFF	1
	Project Analyst - Facilities & RE	CORP+REG AFF	2
	Project Development Coord	CORP+REG AFF	1
	Specialized Services Team Ldr	CORP+REG AFF	1
	Sr Advsr Aboriginal Relations	CORP+REG AFF	2
	Sr Communications Coordinator	CORP+REG AFF	1

YEAR	JOB CATEGORY	LOB	# HIRED
2010	Sr Mgr, First Nations & Metis	CORP+REG AFF	2
	Sr Real Estate Coordinator	CORP+REG AFF	1
	Warehouse Operations Supvr	CORP+REG AFF	2
	Administrative Assistant	CORP+REG AFF	1
	Assistant Facilities Administrator	CORP+REG AFF	1
	Stockkeeper	CORP+REG AFF	2
	New Grad	CORP+REG AFF	2
	Assistant Staffing Consultant	CRP SERVICES	1
	Business Solution Manager	CRP SERVICES	3
	Eng/Off-Transmission Opg Tools	CRP SERVICES	2
	HR Systems Analyst	CRP SERVICES	1
	Labour Relations Assistant	CRP SERVICES	1
	Manager, Business Continuity	CRP SERVICES	1
	Shift Control Engineer/Officer	CRP SERVICES	2
	Financial Analyst	CRP SERVICES	1
	Sr Advr Bus Cont & Emerg Pln	CRP SERVICES	1
	Human Resources Consultant	CRP SERVICES	1
	Information Technology Techn	CRP SERVICES	1
	Area Distr Eng Tech Trainee	CUST OPER	9
	Area Distribution Eng Techn	CUST OPER	5
	Customer Consultant	CUST OPER	1
	Customer Operations Manager	CUST OPER	1
	Distribution/Transmn Forester	CUST OPER	1
	Reg Maintainer I - Forestry	CUST OPER	9
	Regional Maintainer II - Lines	CUST OPER	49
	Sr Products Coordinator	CUST OPER	2
	Technical Srvcs Eng/Off	CUST OPER	1
	Administrative Assistant	CUST OPER	1
	Area Forestry Technician	CUST OPER	3
	Assistant Network Mgmt Eng/Off	CUST OPER	2
	Customer Program Manager	CUST OPER	1
	Distribution Eng Design Tech	CUST OPER	1
	Field Support Clerk	CUST OPER	6
	Lines Customer Support Clerk	CUST OPER	11
	Lines Office Clerk	CUST OPER	4

YEAR	JOB CATEGORY	LOB	# HIRED
2010	Regional Maintainer-Lines Impr	CUST OPER	1
	Regional Mntnr II - Forestry	CUST OPER	24
	Regl Mntner-Forestry Improver	CUST OPER	4
	Settlement Analyst	CUST OPER	1
	Stockkeeper	CUST OPER	3
	Stockkeeper Uts Level 2	CUST OPER	1
	Truck Driver Class 1	CUST OPER	1
	New Grad	CUST OPER	5
	Administrative Assistant	ENG+CST SRV	3
	Assistant Network Mgmt Eng/Off	ENG+CST SRV	5
	CAD Oper Elect & Tele Trainee	ENG+CST SRV	11
	CAD Oper Layout/Elect Trainee	ENG+CST SRV	1
	CAD Operator Elect & Telecom	ENG+CST SRV	2
	CAD Operator Mech/Civil/Struct	ENG+CST SRV	5
	Manager Lines Engineering	ENG+CST SRV	1
	Network Mgmt Eng/Off	ENG+CST SRV	6
	Protection&Control Engr/Offr	ENG+CST SRV	6
	Senior Protection And Control Engineer/O	ENG+CST SRV	2
	Team Ld - Equipment Engineer	ENG+CST SRV	1
	Team Ld Stations Engineering	ENG+CST SRV	1
	Waste Coordinator	ENG+CST SRV	1
	Area Superintendent	ENG+CST SRV	12
	Ass't Construction Technician	ENG+CST SRV	1
	CAD Oper Mech/Cvl/StrcTrainee	ENG+CST SRV	1
	Computer Applications Tech	ENG+CST SRV	1
	Drawing Records Clerk	ENG+CST SRV	1
	Dsgn Engr-Speclist-Structural	ENG+CST SRV	1
	Estimating Sched & Cost Techn	ENG+CST SRV	1
	Field Support Clerk	ENG+CST SRV	1
	General Office Assistant	ENG+CST SRV	1
	Junior Records Clerk	ENG+CST SRV	2
	Project Manager	ENG+CST SRV	1
	Records Clerk	ENG+CST SRV	1
	Senior Cae Application Eng/Off	ENG+CST SRV	1
	Waste Coordinator - Uts Lvl 2	ENG+CST SRV	1
	New Grad	ENG+CST SRV	25
	Insurance and Claims Analyst	FINANCE	1

YEAR	JOB CATEGORY	LOB	# HIRED
2010	Senior Advisor, Treasury	FINANCE	1
	Sr Fin Advr Int Fin Rpt & Cnt	FINANCE	1
	Sr. Fin Advr - Bus Controls	FINANCE	1
	Sr Financial Advr - Corp Func	FINANCE	1
	Administrative Assistant	GNRL COUNSEL	3
	Administrative Assistant	GRID OPS	1
	Assistant Fleet Engineer	GRID OPS	1
	Grid Operations Field Mgr	GRID OPS	2
	Grid Operations Manager	GRID OPS	1
	Grid Operations Planning Mgr	GRID OPS	1
	Network Mgmt Eng/Off	GRID OPS	2
	Prot and Control Tech Trainee	GRID OPS	13
	Pwr Equipt Comp Refinisher-JP	GRID OPS	1
	Regional Maintainer II - Elect	GRID OPS	2
	Services Specialist - CMS	GRID OPS	1
	Sr Protection Performance Tech	GRID OPS	1
	TWE Clerk	GRID OPS	1
	AMI Operator	GRID OPS	2
	Data Analyst & Customer Support	GRID OPS	1
	Grid Ops Dispatcher Trainee	GRID OPS	2
	Meter Control & Scheduling Clk	GRID OPS	1
	Reg Maint - Power Equip Elec	GRID OPS	4
	Regional Field Mechanic JP	GRID OPS	4
	Regional Mntner-Mech Improver	GRID OPS	2
	Regional Mntr-Elect Improver	GRID OPS	18
	New Grad	GRID OPS	25
	Trg Officer - Protection and Control	HLTH SAFE+EN	2
	Work Methods Tech D/T Lines	HLTH SAFE+EN	2
	Sr Health Safety & Env Advisor	HLTH SAFE+EN	1
	Instructor - Stations	HLTH SAFE+EN	1
	Disability Mgmt Consultant	HLTH SAFE+EN	1
	Work Methods Specialist	HLTH SAFE+EN	1
	New Grad	HLTH SAFE+EN	2
	Planning Scheduling Tech'n	#N/A	1
	Total		**406**

YEAR	JOB CATEGORY	LOB	# HIRED
2011	Joint Use Programs Eng/Off	ASSET MGMT	1
	New Grad	ASSET MGMT	1
	Manager, Systems & Operations Audits	AUDIT	1
	HR Controls Analyst	CORP SUPPORT	1
	Sr Mgr Income Tax Compliance	CORP SUPPORT	1
	Insurance and Claims Analyst	CORP SUPPORT	1
	Sr Fin Advr Ext Fin Rpt & Cnt	CORP SUPPORT	1
	Accounting & Financial Analyst	CORP SUPPORT	1
	Human Resources Analyst	CORP SUPPORT	1
	New Grad	CORP SUPPORT	3
	Reg Maintainer I - Forestry	CUST OPER	7
	Regional Mntnr II - Forestry	CUST OPER	2
	New Grad	CUST OPER	1
	CAD Oper Elect & Tele Trainee	ENG+CST SRV	3
	CAD Oper Layout/Elect Trainee	ENG+CST SRV	2
	Team Ld Stations Engineering	ENG+CST SRV	1
	CAD Oper Mech/Cvl/StrcTrainee	ENG+CST SRV	2
	New Grad	ENG+CST SRV	1
	New Grad	FINANCE	1
	Senior Legal Counsel	GNRL COUNSEL	2
	Legal Counsel	GNRL COUNSEL	1
	AMI Operator	NTW OPRTNS	2
	CAD Oper Elect & Tele Trainee	NTW OPRTNS	5
	CAD Operator Layout/Elect	NTW OPRTNS	1
	CAD Operator Mech/Civil/Struct	NTW OPRTNS	2
	Customer Operations Manager	NTW OPRTNS	1
	Distribution Lines Eng/Officer	NTW OPRTNS	1
	Grid Operations Field Mgr	NTW OPRTNS	1
	Grid Operations Manager	NTW OPRTNS	3
	Grid Ops Controller Trainee	NTW OPRTNS	9
	Manager Helicopter Operation	NTW OPRTNS	2
	Meter Technician - Cus Srv	NTW OPRTNS	1
	Project Mgr, Facilities & RE	NTW OPRTNS	1
	Prot and Control Tech Trainee	NTW OPRTNS	5

YEAR	JOB CATEGORY	LOB	# HIRED
2011	Sr Strategy & Conservation Specialist	NTW OPRTNS	1
	Air Engineer	NTW OPRTNS	1
	AMI Operator	NTW OPRTNS	3
	Area Construction Manager	NTW OPRTNS	1
	Assistant Network Mgmt Eng/Off	NTW OPRTNS	1
	Ass't Construction Technician	NTW OPRTNS	1
	Distribution Eng Design Tech	NTW OPRTNS	1
	Field Business Clerk	NTW OPRTNS	2
	Field Support Clerk	NTW OPRTNS	2
	Helicopter Pilot	NTW OPRTNS	1
	Information Technology Analyst	NTW OPRTNS	1
	Junior Records Clerk	NTW OPRTNS	2
	Lines Customer Support Clerk	NTW OPRTNS	4
	Lines Office Clerk	NTW OPRTNS	3
	Meter Data & Nwtrk Operations	NTW OPRTNS	3
	Meter Reader/Data Collector	NTW OPRTNS	1
	Planning Scheduling Tech'n	NTW OPRTNS	2
	Prot and Control Tech Trainee	NTW OPRTNS	1
	Reg Maint - Power Equip Elec	NTW OPRTNS	1
	Reg Mtnr - Pwr Equp Elec Impvr	NTW OPRTNS	11
	Regional Field Mechanic JP	NTW OPRTNS	5
	Regional Maintainer II - Elect	NTW OPRTNS	1
	Regional Maintainer II - Lines	NTW OPRTNS	76
	Regional Maintainer II - Mech	NTW OPRTNS	1
	Regional Mntner-Mech Improver	NTW OPRTNS	2
	Regional Mntnr - Lines UTS 3	NTW OPRTNS	1
	Regional Mntnr II - Forestry	NTW OPRTNS	17
	Regional Mntr-Elect Improver	NTW OPRTNS	12
	Regl Mntner-Forestry Improver	NTW OPRTNS	6
	Stations Site Infrastructure Srvcs Spec	NTW OPRTNS	1
	Stockkeeper	NTW OPRTNS	2
	Telecommunications Engineer/Of	NTW OPRTNS	1
	TWE Clerk	NTW OPRTNS	2
	Waste Coordinator	NTW OPRTNS	1
	New Grad	NTW OPRTNS	16
	Administrative Assistant	STRATEGY	2
	Mgr Corporate Communications	STRATEGY	1

YEAR	JOB CATEGORY	LOB	# HIRED
2011	Sr IT Security Specialist	STRATEGY	1
	Assistant Network Mgmt Eng/Off	STRATEGY	2
	Mgr, Standards Strategy and Processes	STRATEGY	1
	Display Support Technologist	STRATEGY	1
	Ass't Eng/Off -Ops Tools & Fac	STRATEGY	1
	Eng/Off-Transmission Opg Tools	STRATEGY	1
	New Grad	STRATEGY	4
	TOTAL		**270**
2012	Assistant Network Mgmt Eng/Off	NTW OPRTNS	1
	Job Clerk	NTW OPRTNS	1
	Lines Customer Support Clerk	NTW OPRTNS	1
	Mechanic "B"	NTW OPRTNS	1
	Protection And Control Eng	NTW OPRTNS	1
	Regional Maintainer II - Lines	NTW OPRTNS	50
	Regional Mntnr - Lines UTS 3	NTW OPRTNS	1
	Regional Mntnr II - Forestry	NTW OPRTNS	4
	Regional Mntr II-Cable Splicer	NTW OPRTNS	1
	Special Services Support Clerk	NTW OPRTNS	1
	Sr Products Coordinator	NTW OPRTNS	1
	Sr Business Analyst	NTW OPRTNS	1
	Disability Mgmt Consultant	NTW OPRTNS	1
	Manager, Fleet Services	NTW OPRTNS	1
	Meter Technician - Cus Srv	NTW OPRTNS	1
	Occupational Health Nurse	NTW OPRTNS	1
	Prot and Control Tech Trainee	NTW OPRTNS	2
	Reg Maintainer I - Forestry	NTW OPRTNS	18
	Regional Mntnr II - Forestry	NTW OPRTNS	2
	Sr Health Safety & Env Advisor	NTW OPRTNS	1
	New Grad	NTW OPRTNS	17
	Manager Taxation	CORP SUPPORT	1
	Sr. Fin Advr - Bus Controls	CORP SUPPORT	1
	Dir Corporate Account & Reprt	CORP SUPPORT	1
	Sr Mgr Income Tax Compliance	CORP SUPPORT	1
	Administrative Assistant	GNRL COUNSEL	1
	Legal Counsel	GNRL COUNSEL	1

YEAR	JOB CATEGORY	LOB	# HIRED
2012	Information Technology Techn	STRATEGY	1
	Sr Media Relations Officer	STRATEGY	1
	Manager Public Affairs	STRATEGY	1
	Eng/Of f - Tx//Dx Operating Tools	STRATEGY	1
	Telecommunications Eng/Offr	STRATEGY	1
	Eng/Of f - Tx//Dx Operating Tools	STRATEGY	1
	Display Support Technologist	STRATEGY	1
	Human Resources Assistant	STRATEGY	2
	New Grad	STRATEGY	3
	(AS OF JUNE) 2012 TOTAL		**126**

Summary of New Positions by Representation Group:

YEAR	MCP	SOC	PWU
2010	42	132	232
2011	20	40	210
2012	12	28	86
	74	**200**	**528**

Consumers Council of Canada (CCC) INTERROGATORY #23 List 1

Issue 7 **Are the 2013/2014 Human Resources related costs (wages, salaries, benefits, incentive payments, labour productivity and pension costs) including employee levels appropriate? Has Hydro One demonstrated improvements in efficiency and value for dollar associated with its compensation costs?**

Interrogatory

(Ex. A/TI3/S1/Appendix A) There is a 2.5% economic increase effective April!, 2012 for the Society. Why is it assumed that economic increases will remain at 3% for the term of the business plan? What would be the impact on the 2013 and 2014 revenue requirements if the Society increases were limited to 2%? What would be the impact of they were limited to 2.5%?

Response

Compensation for represented staff is determined through the collective bargaining process. There are many factors that affect the final settlement, including considerations such as history of the company, external settlements within the electricity sector, legislation, shareholder/government directives, financial performance, labour market considerations, bargaining unit expectations, recruitment, retention, employee engagement, demographics etc. Other factors to be considered are discussed throughout Exhibit C1, Tab 5, Schedule 2.

If Society increases were limited to 2%, revenue requirement would be lower by $0.40M in 2013 and $0.45M in 2014. If Society increases were limited to 2.5%, revenue requirement would be lower by $0.20M in 2013 and $0.22M in 2014.

Consumers Council of Canada (CCC) INTERROGATORY #24 List 1

Issue 7 **Are the 2013/2014 Human Resources related costs (wages, salaries, benefits, incentive payments, labour productivity and pension costs) including employee levels appropriate? Has Hydro One demonstrated improvements in efficiency and value for dollar associated with its compensation costs?**

Interrogatory

(Ex. A/TI3/Sl/Appendix A, p. 3) What would be the impact on the 2013 and 2014 Revenue Requirements if the PWU increase was limited to 2% per year? What would be the impact if the increase was limited to 2.5% per year?

Response

If PWU increases were limited to 2%, revenue requirement would be lower by $0.85M in 2013 and $0.96M in 2014. If PWU increases were limited to 2.5%, revenue requirement would be lower by $0.43M in 2013 and $0.48M in 2014.

Consumers Council of Canada (CCC) INTERROGATORY #25 List 1

Issue 7 **Are the 2013/2014 Human Resources related costs (wages, salaries, benefits, incentive payments, labour productivity and pension costs) including employee levels appropriate? Has Hydro One demonstrated improvements in efficiency and value for dollar associated with its compensation costs?**

Interrogatory

(Ex. A/T13/S1/Appendix A, p. 3) What would be the impact on the 2013 and 2014 Revenue Requirements if the MCP annual increase in base pay was limited to 2% per year? What would be the impact if it was limited to 2.5% per year?

Response

If MCP increases were limited to 2%, revenue requirement would be lower by $0.23M in 2013 and $0.26M in 2014. If MCP increases were limited to 2.5%, revenue requirement would be lower by $0.11M in 2013 and $0.13M in 2014.

Consumers Council of Canada (CCC) INTERROGATORY #26 List 1

Issue 7 **Are the 2013/2014 Human Resources related costs (wages, salaries, benefits, incentive payments, labour productivity and pension costs) including employee levels appropriate? Has Hydro One demonstrated improvements in efficiency and value for dollar associated with its compensation costs?**

Interrogatory

(Ex. C1/T5/S2) Please explain all of the initiatives HONI is undertaking to reduce its overall compensation costs. Please provide examples of how those initiatives have reduced compensation levels.

Response

Please refer to Exhibit C1, Tab 5, Schedule 2, pp. 3-4 for examples of compensation reduction initiatives.

In the last round of collective bargaining with the Power Workers' Union, Hydro One has been able to reduce compensation costs by:

- increasing the pension contributions for PWU members
- increasing the availability of non regular resources
- requiring some Hiring Hall resources to have mandatory training before commencing work at Hydro One

In the last round of collective bargaining with the Society of Energy Professionals, Hydro One has been able to reduce compensation costs by:

- Elimination of 1% Performance Pay
- Upper end of salary schedules reduced
- New lower hiring rates.

Association of Major Power Consumers in Ontario (AMPCO) INTERROGATORY #4 List 1

Issue 7 **Are the 2013/14 Human Resources related costs (wages, salaries, benefits, incentive payments, labour productivity and pension costs) including employee levels appropriate? Has Hydro One demonstrated improvements in efficiency and value for dollar associated with its compensation costs?**

Interrogatory

Ref: Ex A-13-1 Appendix A
Ref: Ex C1-5-2 Attachment 1 Table 7

Preamble:
In Hydro One's 2012 Business Planning Assumptions, Hydro One projects Ontario CPI to increase 2.1% for the 2012-2013 period and 2.0% in the 2014-2016 period. At the same time, economic increase are projected at 3.0% for both PWU and Society represented staff. The Mercer study in C1-5-2 Attachment 1 indicates that PWU weighted average wages remain at 18% above the median of its comparator group.

a) Is Hydro One planning to continue closing the gap between the wages it pays to its represented workers and those of it's comparator group?
b) If the answerto a) is yes, please provide an analysis of how Hydro One plans to achieve this goal while planning for wage rate increases in excess of CPl. Please provide any supporting evidence Hydro may have used to develop such plans, such as projected rates of wage inflation in the comparator group.

Response

a) Yes, Hydro One plans to continue to close the gap between the wages paid to our represented employees and those of its comparator group.

b) Changes to compensation paid to represented workers can only be accomplished through the collective bargaining process. Hydro One has a solid track record of achieving reasonable settlements that benefit the company, our employees and ultimately, the ratepayers. Hydro One will continue to attempt to negotiate reasonable collective agreements with its represented employees.

   Evidence to support that Hydro One is making gains is already happening. The Mercer Report states:

> ‘The Hydro One positioning shift towards the median is notable given that the peer group, like Hydro One, has worked to minimize labour costs through the substantial economic downturn which ensued between the 2008 and 2011 compensation cost benchmarking studies’.

In other words, in a time where most organizations are attempting to reduce compensation related costs, Hydro One is making up ground through its own compensation reduction strategies.

While Hydro One does not have specific projected wage forecasts for the peer group used in the Mercer Study, Hay Consulting is forecasting 2013 Base Pay increases to be 2.9% (all organizations) and 3.1% (Utilities). Mercer Consulting is forecasting 2013 Base Pay increases to be 3.2% (all industries) and 3.3% (Utilities).

Association of Major Power Consumers in Ontario (AMPCO) INTERROGATORY #5 List 1

Issue 7 **Are the 2013/14 Human Resources related costs (wages, salaries, benefits, incentive payments, labour productivity and pension costs) including employee levels appropriate? Has Hydro One demonstrated improvements in efficiency and value for dollar associated with its compensation costs?**

Interrogatory

Ref: C1-5-2-P8 lines 23-25

a) Does Hydro One have any measured experience of difficulty in attracting qualified people to replenish it's PWU workforce at current new employee compensation levels? If so, please provide non-anecdotal details if possible.
b) Does Hydro One have any non-anecdotal reports of difficulty by members of it's comparator group in hiring appropriately qualified people into their unionized workforces?

Response

The reference above seems to be incorrect. It is assumed the correct line reference is lines 4-6.

a) The reference to external recruitment proving challenging due to compensation levels falling below market median is a specific reference to attracting MCP staff. While there is no independent report to support this evidence, anecdotal experience supports this statement

b) No.

<u>Association of Major Power Consumers in Ontario (AMPCO) INTERROGATORY #6 List 1</u>

Issue 7 **Are the 2013/14 Human Resources related costs (wages, salaries, benefits, incentive payments, labour productivity and pension costs) including employee levels appropriate? Has Hydro One demonstrated improvements in efficiency and value for dollar associated with its compensation costs?**

Interrogatory

Ref: C1-5-2 Table 1 and lines 16-21

a) Please provide the hourly wage rate for the Regional Maintainer- lines position noted in line 16-21.
b) Please indicate how many journeyman level Regional Maintainer- lines there are in Hydro One and how many journeyman level Power linemen.

Response

a) The Hourly rate for the Regional Maintainer – Lines is $41.85 /hr (2012)

b) Hydro One no longer places employees in the Power lineman classification. The Regional Maintainer - Lines classification is based upon the Power Line Maintainer classification with additional duties. There are 537 Regional Maintainer – Lines as of June 30th 2012.

Association of Major Power Consumers in Ontario (AMPCO) INTERROGATORY #7 List 1

Issue 7 **Are the 2013/14 Human Resources related costs (wages, salaries, benefits, incentive payments, labour productivity and pension costs) including employee levels appropriate? Has Hydro One demonstrated improvements in efficiency and value for dollar associated with its compensation costs?**

Interrogatory

Ref: C1-5-2 P2-3

Preamble:
In reviewing the results of the Mercer study, the text on these pages refers to the "market median" as opposed to the "peer group" median. The peer group used in the Mercer study was composed of like organizations, but may not necessarily reflect the marketplace in which Hydro One competes for skilled workers and managers.

a) Does Hydro regard organizations meeting the Mercer peer group criteria as the primary or sole marketplace in which it competes for skills or does it regard the marketplace as considerably larger?
b) Please identify the voluntary, non-retirement attrition rate for each of the three groups (Management, PWU, Society-represented) for the 2008-2011 period.
c) Please identify what proportion of new hires have come from the peer group or other organizations fitting the peer group criteria in the Mercer study, broken down in the PWU, Society –represented and management groupings, for the 2008-2011 period.
d) Please identify what proportion of Hydro One's non-retirement, voluntary attrition has been to the same peer group, broken down by PWU, Society-represented and management, for the 2008-2011 period.
e) Please provide any information Hydro One may have commissioned or received with regards to comparative wages and salaries for utility engineering professionals employed by non-utilities, such as engineering firms.

Response

a) The peer group in the Mercer Study is a reasonable representation of the labour market for which Hydro One competes in for human resources. The actual marketplace would be larger.

b)

Year	**MCP**	**Society**	**PWU**
2008	1.6%	2.0%	.6%
2009	.16%	.94%	.18%
2010	1.5%	1.0%	.21%
2011	1.4%	1.1%	.4%

c) This data is not available. It would require a review of all resumes over this period of time and it would assume Hydro One would have access to the scoping criteria used in the Mercer Study for all these organizations.

d) This data is not available. Terminating employees often do not disclose the organizations that they are joining after leaving Hydro One.

e) No such reports to disclose.

Energy Probe (EP) INTERROGATORY #50 List 1

Issue 8 **Are the methodologies used to allocate Shared Services and Other O&M costs to the transmission business and to determine the transmission overhead capitalization rate for 2013/14 appropriate?**

Interrogatory

Ref: Exhibit C1, Tab 4, Schedule 2, Page 2, Table 1 &
Exhibit C1, Tab 7, Schedule 1, Page 3, Table 1 and Table 2 &
Exhibit C1, Tab 7, Schedule 1. Attachment 1

One of the difficulties in examining CCF&S costs is the inclusion/exclusion of Inergi costs.

a) Please provide a version of Exhibit C1/Tab 4/Schedule 2/Page 2 Table 1 that shows the total year over year % increase and the % increase in allocation to Tx.

b) Please provide a version of C1/Tab 2/Schedule 7/Page 3 Table 1 that shows the Total CCFS costs as reviewed by B&V and as allocated to the Business Units per Table 3 of the B&V Report.

c) Reconcile to C1/Tab 7/Schedule 1/Page 3 Table 1 and Table 2.

d) Please provide a copy of BP-2012-2016 (source data for B&V).

e) Reconcile the CCF&S costs for 2012 with the Schedules A&B in the Service Level Agreements (see IR above).

f) How are Inergi costs allocated to the Business Units? (direct cost driver etc).

g) Please provide a Schedule that shows by service the total 2013 costs allocated to the business units with separate costs shown for in-house and Inergi costs. Reconcile to the total shown in the B&V report Table 3.

Response

a) Provided below is the requested table that shows the total year over year % increase and the % increase in allocation to Transmission

Description	Historic 2010 over 2009	Historic 2011 over 2010	Bridge 2012 over 2011	Test 2013 over 2012	Test 2014 over 2013	Transmission Allocation Test 2014 over 2013
Corporate Management	-17%	2%	2%	2%	2%	1%
Finance	2%	2%	8%	-1%	0%	0%
Human Resources	5%	-33%	-1%	0%	3%	-1%
Corporate Communications	8%	-9%	5%	25%	11%	-1%
General Counsel & Secretariat	14%	-1%	18%	2%	2%	0%
Regulatory Affairs	9%	-6%	11%	5%	-3%	-7%
Corporate Security	14%	25%	23%	3%	3%	-1%
Internal Audit	4%	11%	35%	2%	2%	1%
Real Estate & Facilities	-1%	3%	17%	4%	3%	0%
Total CCF&S Costs	3%	-3%	12%	4%	2%	-1%

b) The table below shows how Exhibit C1, Tab 4, Schedule 2, Table 1 reconciles with the updated total CCFS costs used in the Shared Services Cost Allocation model.

Description	2013	2014	2013 TX	2014 TX
Corporate Management	5.3	5.4	2.7	2.8
Finance	34.0	34.0	19.5	19.5
Human Resources	10.9	11.2	6.4	6.5
Corporate Communications	11.4	12.6	5.3	5.7
General Counsel & Secretariat	8.9	9.1	4.7	4.8
Regulatory Affairs	23.6	23.0	11.5	9.7
Corporate Security	3.8	3.9	1.8	1.8
Internal Audit	4.3	4.4	2.5	2.6
Real Estate & Facilities	62.5	64.3	31.8	32.7
CF&S Costs (Note 1)	**164.8**	**167.9**	**86.1**	**86.1**
Customer Care	45.43	44.21	0.23	0.24
Facilities (Note 2)	(52.40)	(54.03)	(23.58)	(24.31)
Information Technology Systems	110.22	107.23	50.72	49.36
New: Strategy	62.52	62.75	35.82	37.04
New: Operations	66.48	69.29	37.70	38.77
Other	1.25	1.25	-	-
Total CCF&S Costs	**398.3**	**398.6**	**187.0**	**187.2**
Less: Blue page adjustments	(1.5)	-	(1.5)	-
CCF&S per Table 3 of the B&V Report	**396.8**	**398.6**	**185.5**	**187.2**

Note 1: CF&S costs are consistent with C1-2-7 Table 2
Note 2: Facilities costs are not included in the cost allocation model reviewed by Black & Veatch Corporation.

c) The table in response b) reconciles to Exhibit C1, Tab 7, Schedule 1, Page 3 Table 1 and Table 2.

d) Please refer to documents filed in confidence in response to Exhibit I, Tab 2, Schedule 3.01 EP 1.

e) Please refer to the response to Exhibit I, Tab 6, Schedule 3.04 EP 25.

f) Inergi costs are allocated to the Business Units using direct allocation and cost drivers.

g) The table on the next page shows by service the total 2013 costs allocated to the business units with separate costs shown for in-house and Inergi costs.

	2013						
Description	**2013 Total**	**Tx**	**Dx**	**Telecom**	**Brampton**	**Remotes**	**Share-holder Only**
Corporate Management	5.3	2.7	2.3	0.1	0.1	0.1	0.1
Finance	22.0	12.6	8.7	0.2	0.2	0.2	0.1
Inergi - Finance	*7.8*	*4.4*	*3.2*	*0.2*	-	*0.0*	-
Inergi - HR	*4.3*	*2.5*	*1.7*	*0.1*	-	*0.0*	-
Human Resources	10.9	6.4	4.3	0.2	-	0.1	-
Corporate Communications	11.4	5.3	6.1	-	-	0.1	-
General Counsel & Secretariat	8.9	4.7	3.6	0.1	0.2	0.2	0.1
Regulatory Affairs	23.6	11.5	12.0	-	-	0.1	-
Corporate Security	3.8	1.8	2.0	0.0	0.0	0.0	-
Internal Audit	4.3	2.5	1.3	0.1	0.2	0.1	0.0
Real Estate & Facilities	62.5	31.8	30.7	-	-	0.0	-
CF&S Costs (Note 1)	**164.8**	**86.1**	**75.9**	**0.9**	**0.7**	**0.9**	**0.2**
Customer Care							
Inergi - CSO	*40.9*	*0.0*	*40.8*	*0.0*	*0.0*	*0.0*	*0.0*
Inergi - Settlements	*4.6*	*0.2*	*4.3*	*0.0*	*0.0*	*0.0*	*0.0*
Total	45.4	0.2	45.2	0.0	0.0	0.0	0.0
Information Technology Systems							
Inergi - ETS	*71.9*	*28.7*	*42.3*	*0.6*	*0.0*	*0.2*	*0.0*
Telecom Services	18.0	10.4	7.2	0.3	0.0	0.1	0.0
Information Technology Systems	20.3	11.5	8.6	0.1	0.0	0.0	0.0
Total	110.2	50.7	58.1	1.0	0.0	0.4	0.0
Operations							
Inergi - AP	*1.4*	*0.8*	*0.5*	*0.1*	*0.0*	*0.0*	*0.0*
Operations	65.0	36.9	28.2	0.0	0.0	0.0	0.0
Total	66.5	37.7	28.6	0.1	0.0	0.0	0.0
Strategy	62.5	35.8	26.7	0.0	0.0	0.0	0.0
Facilities (Note 2)	-52.4	-23.6	-28.8	0.0	0.0	0.0	0.0
Direct HOI Costs	1.3	0.0	0.0	0.0	0.0	0.0	1.3
Total CCF&S Costs	**398.3**	**187.0**	**205.7**	**2.0**	**0.7**	**1.3**	**1.5**
Less: Blue page adjustments	(1.5)	(1.5)	-	-	-	-	-
CCF&S per Table 3 of the B&V Report	**396.8**	**185.5**	**205.7**	**2.0**	**0.7**	**1.3**	**1.5**

Note 1: CF&S costs are consistent with C1-2-7 Table 2
Note 2: Facilities costs are not included in the cost allocation model reviewed by Black & Veatch Corporation.

Energy Probe (EP) INTERROGATORY #51 List 1

Issue 8 **Are the methodologies used to allocate Shared Services and Other O&M costs to the transmission business and to determine the transmission overhead capitalization rate for 2013/14 appropriate?**

Interrogatory

Ref. Exhibit C1, Tab 7, Schedule 2, Attachment 1, Appendix

a) The formula on page 7 uses the total CAPEX as the denominator. Confirm that the CAPEX includes Capital contributions.

b) Explain why it is appropriate for the Overhead Capitalization Rate result to be affected by Capital contributions and if Rate base was the denominator whether less variability would occur.

c) Please provide versions of Appendix A that
   i) removes capital contributions and
   ii) uses ratebase as the denominator.

Response

a) Yes, the CAPEX amount in the denominator includes Capital Contributions by customers.

b) Capital Contributions by Customers are added because the Overhead effort required for projects is related to the gross capital cost, not net capital cost. The fact that a project is funded in part by customers is a financial transaction and does not relate to the Overhead effort required.

   It is not possible to tell if using the Rate Base for the denominator, instead of Capital Spending, would cause the ratio to be more or less variable than the Company's method. While the Rate Base may be less variable than Capital Spending, the Overhead Cap Rate that is calculated could be either more or less variable. That is because Overhead costs for capital projects are more directly related to Capital Spending (as computed by the Company for use in the Overhead Cap Rate) than to Rate Base, which is not as affected by annual Capital Spending.

c)
   i). Attachment 1 of this exhibit shows the Overhead Cap Rate computed by removing Capital Contributions (line 84). While these rates are higher than the rates computed by Hydro One (line 83), the costs capitalized under this approach

(line 79) is lower than computed by Hydro One (line 80) because the higher rate gets applied to a lower amount (that is, Capital Spending without including Capital Contributions).

ii). Attachment 2 of this exhibit shows the Overhead Cap Rate computed by using the Rate Base (line 82) as the denominator instead of Capital Spending (line 83). These rates are not comparable to the rates computed by Hydro One because they are applied to a much higher number (i.e., Rate Base instead of annual Capital Spending).

REMOVE CAPITAL CONTRIBUTIONS FROM CAPITAL SPENDING

TRANSMISSION OVERHEAD CAPITALIZATION RATES

	($ millions)	**2012**	**2013**	**2014**	**2015**	**2016**
1	**Capital Expenditures**					
2	Total capexp	974.2	1,070.4	1,088.5	985.9	1,067.6
3	Less: Minor fixed assets	(31.4)	(26.0)	(27.3)	(25.4)	(25.9)
4	Less: Capitalized overhead	(115.2)	(116.5)	(117.0)	(109.9)	(111.2)
5	Less: Capitalized interest	(48.9)	(43.7)	(56.4)	(59.9)	(57.6)
6	Add: Capital contributions					
7	Add: Removal costs	23.9	35.9	36.2	41.9	35.8
8		802.7	920.1	924.1	832.7	908.6
9						
10	**OM&A**					
11	Total OM&A	430.6	452.0	459.8	485.2	499.7
12	Less: CCF&S costs	(113.5)	(113.2)	(112.6)	(113.2)	(113.2)
13	Less: Facility costs	(22.2)	(22.7)	(23.5)	(24.0)	(24.5)
14	Less: Asset Management \1	(71.7)	(71.6)	(73.0)	(74.3)	(75.2)
15	Add: Capitalized overheads	115.2	116.5	117.0	109.9	111.2
16		338.3	360.9	367.8	383.6	398.0
17						
18	**Capitalized CCF&S Costs**					
19	Total Costs per Model	184.4	185.5	187.2	189.1	189.9
20	Less: AM	(35.3)	(35.8)	(37.0)	(37.4)	(37.2)
21	Less: Operations	(0.6)	(0.6)	(0.7)	(0.7)	(0.7)
22	Less: Network Operations	(31.4)	(32.2)	(33.2)	(33.9)	(34.9)
23	Less: CBR	(3.6)	(3.6)	(3.7)	(3.8)	(3.9)
24	Net CCF&S Costs	113.5	113.2	112.6	113.2	113.2
25	Add: Facility costs	22.2	22.7	23.5	24.0	24.5
26						
27	Less operating-type CCF&S costs:					
28	Inergi - CSO	-	-	-	-	-
29	Inergi - ETS CSO Apps	-	-	-	-	-
30	Inergi - ETS Market Ready	(1.1)	(1.1)	(1.1)	(1.0)	(1.0)
31	Inergi - Settlements	(0.2)	(0.2)	(0.2)	(0.3)	(0.3)
32		(1.3)	(1.3)	(1.3)	(1.3)	(1.2)
33						
34	Applicable CCF&S costs	134.4	134.6	134.7	135.9	136.5
35						
36	Portion capitalized based on labour content:					
37	Labour in OM&A	154.3	172.3	175.5	196.0	204.2
38	Labour in capexp	237.5	262.1	269.0	244.1	267.9
39		391.8	434.4	444.5	440.1	472.1
40	% capexp	60.6%	60.3%	60.5%	55.5%	56.7%
41						
42	Portion capitalized based on total spending:					
43	OM&A	338.3	360.9	367.8	383.6	398.0
44	Capexp	802.7	920.1	924.1	832.7	908.6
45		1,141.0	1,281.0	1,291.9	1,216.3	1,306.6
46	% capexp	70.3%	71.8%	71.5%	68.5%	69.5%
47						
48	Weighting:					
49	Labour content	50.0%	50.0%	50.0%	50.0%	50.0%
50	Total spending	50.0%	50.0%	50.0%	50.0%	50.0%
51						
52	Portion capitalized based on weighting of two methods	65.5%	66.1%	66.0%	62.0%	63.1%
53						
54	Applicable CCF&S costs	134.4	134.6	134.7	135.9	136.5
55						
56	Capitalized CCF&S costs	88.0	89.0	88.9	84.2	86.2
57						

		REMOVE CAPITAL CONTRIBUTIONS FROM CAPITAL SPENDING				
		TRANSMISSION OVERHEAD CAPITALIZATION RATES				
	($ millions)	**2012**	**2013**	**2014**	**2015**	**2016**
58	**Capitalized AM, NO, OP Costs**					
59	Network AM, NO, OP (Tx + Dx):					
60	Asset Management group	64.2	62.5	62.7	63.4	63.4
61	Network Operating department	45.7	47.0	48.3	49.4	50.8
62	Operations group (certain departments, see Report)	17.3	17.4	18.9	19.8	19.5
63		127.3	126.8	129.9	132.5	133.7
64						
65	Portion capitalized (per time study):					
66	Asset Management group	24.3%	24.3%	24.3%	24.3%	24.3%
67	Network Operating department	11.6%	11.6%	11.6%	11.6%	11.6%
68	Operations group (certain departments, see Report)	4.3%	4.3%	4.3%	4.3%	4.3%
69						
70	Capitalized AM, NO, OP costs:					
71	Asset Management group	15.6	15.2	15.2	15.4	15.4
72	Network Operating department	5.3	5.4	5.6	5.7	5.9
73	Operations group (certain departments, see Report)	0.7	0.8	0.8	0.9	0.8
74		21.6	21.4	21.6	22.0	22.1
75						
76	**Overhead Capitalization Rate**					
77	Capitalized CCF&S costs	88.0	89.0	88.9	84.2	86.2
78	Capitalized AM, NO, OP costs	21.6	21.4	21.6	22.0	22.1
79	**TOTAL SHARED COSTS CAPITALIZED**	109.6	110.3	110.6	106.2	108.3
80	*As filed by Hydro One*	*112.6*	*113.8*	*114.3*	*107.3*	*108.5*
81	Capexp	802.7	920.1	924.1	832.7	908.6
82						
83	**Overhead capitalization rate**	**14.0%**	**12.0%**	**12.0%**	**13.0%**	**12.0%**
84	*As filed by Hydro One*	*11.0%*	*9.0%*	*9.0%*	*12.0%*	*12.0%*
85	\1 Asset Management excludes facility costs					

USE RATE BASE FOR DENOMINATOR

Line	($ millions)	TRANSMISSION OVERHEAD CAPITALIZATION RATES 2012	2013	2014	2015	2016
1	**Capital Expenditures**					
2	Total capexp	974.2	1,070.4	1,088.5	985.9	1,067.6
3	Less: Minor fixed assets	(31.4)	(26.0)	(27.3)	(25.4)	(25.9)
4	Less: Capitalized overhead	(115.2)	(116.5)	(117.0)	(109.9)	(111.2)
5	Less: Capitalized interest	(48.9)	(43.7)	(56.4)	(59.9)	(57.6)
6	Add: Capital contributions	198.2	291.0	310.2	67.1	16.2
7	Add: Removal costs	23.9	35.9	36.2	41.9	35.8
8		1,000.9	1,211.1	1,234.3	899.8	924.7
9						
10	**OM&A**					
11	Total OM&A	430.6	452.0	459.8	485.2	499.7
12	Less: CCF&S costs	(113.5)	(113.2)	(112.6)	(113.2)	(113.2)
13	Less: Facility costs	(22.2)	(22.7)	(23.5)	(24.0)	(24.5)
14	Less: Asset Management \1	(71.7)	(71.6)	(73.0)	(74.3)	(75.2)
15	Add: Capitalized overheads	115.2	116.5	117.0	109.9	111.2
16		338.3	360.9	367.8	383.6	398.0
17						
18	**Capitalized CCF&S Costs**					
19	Total Costs per Model	184.4	185.5	187.2	189.1	189.9
20	Less: AM	(35.3)	(35.8)	(37.0)	(37.4)	(37.2)
21	Less: Operations	(0.6)	(0.6)	(0.7)	(0.7)	(0.7)
22	Less: Network Operations	(31.4)	(32.2)	(33.2)	(33.9)	(34.9)
23	Less: CBR	(3.6)	(3.6)	(3.7)	(3.8)	(3.9)
24	Net CCF&S Costs	113.5	113.2	112.6	113.2	113.2
25	Add: Facility costs	22.2	22.7	23.5	24.0	24.5
26						
27	Less operating-type CCF&S costs:					
28	Inergi - CSO	-	-	-	-	-
29	Inergi - ETS CSO Apps	-	-	-	-	-
30	Inergi - ETS Market Ready	(1.1)	(1.1)	(1.1)	(1.0)	(1.0)
31	Inergi - Settlements	(0.2)	(0.2)	(0.2)	(0.3)	(0.3)
32		(1.3)	(1.3)	(1.3)	(1.3)	(1.2)
33						
34	Applicable CCF&S costs	134.4	134.6	134.7	135.9	136.5
35						
36	Portion capitalized based on labour content:					
37	Labour in OM&A	154.3	172.3	175.5	196.0	204.2
38	Labour in capexp	237.5	262.1	269.0	244.1	267.9
39		391.8	434.4	444.5	440.1	472.1
40	% capexp	60.6%	60.3%	60.5%	55.5%	56.7%
41						
42	Portion capitalized based on total spending:					
43	OM&A	338.3	360.9	367.8	383.6	398.0
44	Capexp	1,000.9	1,211.1	1,234.3	899.8	924.7
45		1,339.2	1,572.0	1,602.1	1,283.4	1,322.8
46	% capexp	74.7%	77.0%	77.0%	70.1%	69.9%
47						
48	Weighting:					
49	Labour content	50.0%	50.0%	50.0%	50.0%	50.0%
50	Total spending	50.0%	50.0%	50.0%	50.0%	50.0%
51						
52	Portion capitalized based on weighting of two methods	67.7%	68.7%	68.8%	62.8%	63.3%
53						
54	Applicable CCF&S costs	134.4	134.6	134.7	135.9	136.5
55						
56	Capitalized CCF&S costs	91.0	92.5	92.7	85.3	86.4
57						

		USE RATE BASE FOR DENOMINATOR				
		TRANSMISSION OVERHEAD CAPITALIZATION RATES				
	($ millions)	**2012**	**2013**	**2014**	**2015**	**2016**
58	**Capitalized AM, NO, OP Costs**					
59	Network AM, NO, OP (Tx + Dx):					
60	Asset Management group	64.2	62.5	62.7	63.4	63.4
61	Network Operating department	45.7	47.0	48.3	49.4	50.8
62	Operations group (certain departments, see Report)	17.3	17.4	18.9	19.8	19.5
63		127.3	126.8	129.9	132.5	133.7
64						
65	Portion capitalized (per time study):					
66	Asset Management group	24.3%	24.3%	24.3%	24.3%	24.3%
67	Network Operating department	11.6%	11.6%	11.6%	11.6%	11.6%
68	Operations group (certain departments, see Report)	4.3%	4.3%	4.3%	4.3%	4.3%
69						
70	Capitalized AM, NO, OP costs:					
71	Asset Management group	15.6	15.2	15.2	15.4	15.4
72	Network Operating department	5.3	5.4	5.6	5.7	5.9
73	Operations group (certain departments, see Report)	0.7	0.8	0.8	0.9	0.8
74		21.6	21.4	21.6	22.0	22.1
75						
76	**Overhead Capitalization Rate**					
77	Capitalized CCF&S costs	91.0	92.5	92.7	85.3	86.4
78	Capitalized AM, NO, OP costs	21.6	21.4	21.6	22.0	22.1
79	**TOTAL SHARED COSTS CAPITALIZED**	112.6	113.8	114.3	107.3	108.5
80	*As filed by Hydro One*	*112.6*	*113.8*	*114.3*	*107.3*	*108.5*
81	Capexp	1,000.9	1,211.1	1,234.3	899.8	924.7
82	**Rate Base**		9,413.5	10,050.9		
83	**Overhead capitalization rate**		**1.0%**	**1.0%**		
84						
85	\1 Asset Management excludes facility costs					

<u>School Energy Coalition (SEC) INTERROGATORY #23 List 1</u>

Issue 8 **Are the methodologies used to allocate Shared Services and Other O&M costs to the transmission business and to determine the transmission overhead capitalization rate for 2013/14 appropriate?**

Interrogatory

[C1-7-2-1]
Please provide the terms of reference and the instructions provided by the Applicant to Black & Veatch regarding t*he review of its overhead capitalization rate.*

Response

Please see Appendix A to this exhibit.

Hydro One Networks Inc.
Request for Proposal
Reference: RFP # SCO-1000150542
Re: Cost Allocation Study

Part 1: Instructions to Proponents

Part 2: Commercial Terms and Conditions

Part 3: Terms of Reference

Part 4: Format for Submission of Proposals

Part 5: Attachments

PART 3: TERMS OF REFERENCE

1.0 Introduction

Hydro One Inc. ("Hydro One" or "the Company") is conducting a competitive selection process for the provision of services that will provide a methodology to allocate common costs and assets as well as an overhead capitalization methodology. The successful proponent should be prepared to commence their service on April 4th , 2011 and complete their proposed methodology/report by June 30th, 2011.

It is anticipated that the successful proponent will be appointed for an initial term of three years to provide services relating to the proposed methodology including yearly reviews of the methodology as well as provided services during a rate application through briefing preparation, responding to interrogatories and potentially testifying before the Ontario Energy Board ("OEB") on the proposed methodology. Hydro One Inc. retains the right to extend the contract for one additional year after the initial three year period.

We invite your firm to participate and to submit a response to this Request for Proposal ("RFP") for the provision of such services.

1.1Background on Hydro One Inc.

Following the enactment of the Electricity Act, 1998 and the anticipated restructuring of the former Ontario Hydro, **Hydro One Inc.** was incorporated under Ontario's Business Corporations Act on December 1, 1998 as Ontario Hydro Services Company Inc. and commenced carrying on business on May 1, 1999. On May 1, 2000, the company's name was changed to Hydro One Inc. In accordance with Section 48.1 of the Electricity Act, 1998, as amended, Hydro One Inc. is a holding company operating through its subsidiaries. Its principal subsidiary, Hydro One Networks is the largest electricity transmitter and distributor to customers within Ontario.

Hydro One's subsidiaries include:

- Hydro One Networks Inc.. (The primary transmitter of electricity and rural distribution utility in Ontario. These businesses are separately regulated by the OEB);
- Hydro One Brampton Networks Inc. (The electrical distribution utility for the City of Brampton, which is separately regulated by the OEB)

- Hydro One Remotes Inc. (The electrical generation and distribution utility to several communities in Northern Ontario, which is separately regulated by the OEB)
- Hydro One Telecom Inc. (A provider of lit and dark fiber telecommunication services, which is regulated by the Canadian Radio-television Telecommunications Commission)

Hydro One Networks has two major business segments. The Transmission Business operates a high-voltage electrical transmission network that represents almost all of the licensed transmission capacity in Ontario. The Distribution Business operates a low-voltage electrical distribution network that distributes electricity from the transmission system, or directly from generators, to customers within Ontario. Distribution customers include small local distribution companies and large industrial customers with loads of less than 5 MW. Both businesses do not have legal status, but are required to be filed with the industry's regulatory body. These statements, along with those of Hydro One and Hydro One Networks Inc, incorporate the concept of regulatory accounting. As such, knowledge and experience in accounting within a regulatory setting is a requirement of this RFP.

More detailed information on Hydro One's corporate structure, internal operations, regulatory environment and lines of business is available in Hydro One's corporate filings at www.sedar.com.

Proposing firms are also encouraged to visit our website at: www.hydroone.com to review Hydro One's:

- History and vision
- Corporate structure
- Innovation, capabilities, corporate objectives and goals
- Leadership and board member profiles
- Financial results
- Recent press releases
- Other pertinent information

Hydro One has been in existence since 1999 and is the successor company to Ontario Hydro's electricity transmission and distribution businesses. We are a public utility operating with a private company corporate structure. Hydro One's sole shareholder is the Province of Ontario. Hydro One has an independent Board of Directors and Audit and Finance Committee.

Hydro One debt is publicly traded and its debt is assessed by credit rating agencies.

Hydro One Inc.. ("Networks") www.hydroonenetworks.com is the largest subsidiary of Hydro One. It is regulated by the OEB and is licensed to transmit and distribute electrical power in Ontario. Networks is Ontario's largest transmission and distribution utility and one of the 10 largest in North America. It operates as an integrated transmission and distribution business with centralized backroom and finance operations.

The OEB sets rates following oral or written public hearings. Our transmission revenues primarily include our transmission tariff, which is based on the uniform province-wide transmission rates approved by the OEB for all transmitters across Ontario. Our distribution revenues primarily include our distribution tariff, which is also based on OEB-approved rates, and the recovery of the cost of purchased power used by our customers. Consequently, our Distribution Business does not have commodity price risk. Transmission and distribution tariff rates are set based on an approved revenue requirement that provides for cost recovery and includes a return on deemed common equity. In addition, the OEB approves rate riders to allow for the recovery or disposition of specific regulatory assets and liabilities over a specified timeframe.

Our distribution business, which represented approximately $6.53 billion of our total assets of $15.81 billion as at December 31, 2009, distributes electricity through our approximately 123,500 circuit-kilometre low-voltage distribution system, to municipalities and to rural areas. Customers of our distribution business include 25 local distribution companies that are not directly connected to our transmission system, 36 customers with loads exceeding 5MW and approximately 1.3 million rural and urban customers. Hydro One Brampton Networks Inc. is our urban distribution company, serving approximately 130,000 customers in the GTA with approximately 2,700 circuit-kilometres of lines. We also operate through our subsidiary, Hydro One Remote Communities Inc., 19 small, regulated generation and distribution systems in 21 remote communities across Northern Ontario that are not connected to Ontario's electricity grid.

Our transmission business, which represented approximately $9.12 billion of our total assets of $15.81 billion as at December 31, 2009, transmits electricity through an approximately 28,900 circuit-kilometre high-voltage network. We transmit electricity from generators to our own distribution networks, to 51 local distribution companies and to 89 transmission connected companies. We also own and operate 26 facilities that interconnect our transmission system with systems in neighbouring provinces and states.

Hydro One Brampton was incorporated on April 25, 2000 under the *Business Corporations Act* (Ontario). Up to October 31, 2006, the Company was a wholly owned subsidiary of Hydro One Brampton Inc. Hydro One Brampton Inc. was legally dissolved on January 30, 2007. As a consequence, the Company is now a wholly owned subsidiary of Hydro One Inc. (Hydro One). The principal business of the Company is the ownership, operation and management of electricity distribution systems and facilities within the City of Brampton, Ontario. The Ontario Energy Board (OEB) regulates the Company.

At December 31, 2009, Hydro One had total assets of $15,810 million and shareholders equity of $5,418 million. Revenues for the 12 months ended December 31, 2009 were $4,744 million and net income was $470 million.

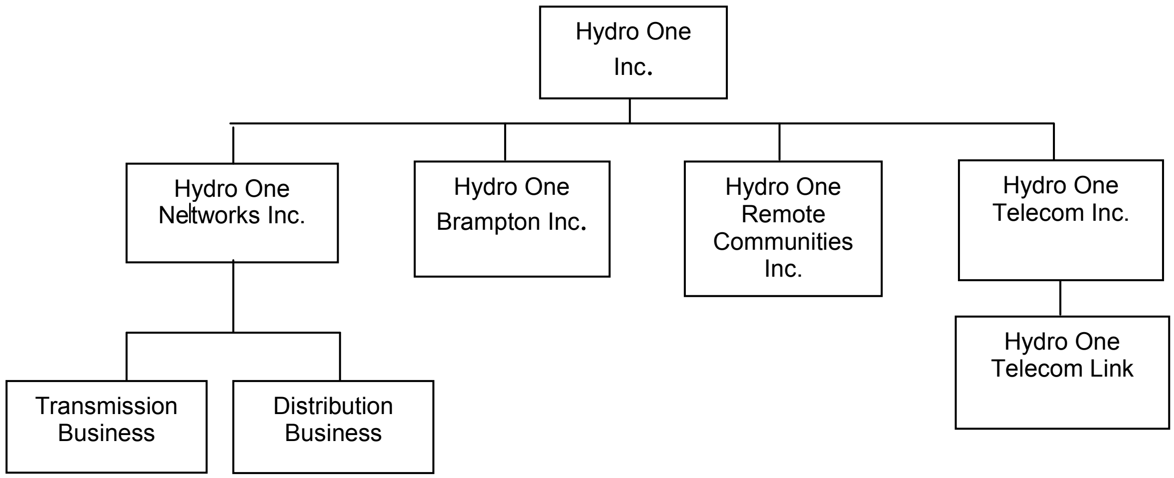
At the end of 2009, our Hydro One Networks Inc. subsidiary had 5,086 regular (i.e., permanent) employees comprised of 609 non-represented executive and managerial staff, 3,307 employees represented by the Power Workers' Union and 1,170 employees represented by the Society of Energy Professionals. Hydro One's finance functions, including most of its accounting, all of its financial statement preparation, its financial statement analysis and reporting, taxation, treasury and financial transaction processing functions are centrally located at its head office at 483 Bay Street in Toronto.

In March 2002, Networks entered into a 10-year Business Process agreement with Inergi LP ("Inergi"), a wholly owned subsidiary of CapGemini Canada. Under the outsourcing agreement Inergi operates the processing functions for the financial, payroll, accounts payable, accounts receivable and settlements functions for the Hydro One Group. Inergi also provides business process functions for the customer call centre, supply chain and procurement processes and maintains and operates the IT environment for the Hydro One Group. To undertake these functions approximately 900 employees of the Hydro One Group, including management, who performed those duties at the Hydro One Group, were transferred to Inergi. These individuals work in close proximity to, and directly with, Hydro One Group staff to carry out their duties. On May 1, 2010, the Company extended the Master Services Agreement (MSA) with Inergi for a further three-year period. The term of the agreement, which would have expired on February 29, 2012, has been extended to February 28, 2015. Under the extended agreement, Inergi will provide business processing and information technology outsourcing services, as well as core system support related primarily to SAP implementation and optimization.

The Hydro One Group uses SAP and CSS as its primary accounting systems. The Company has been converting to SAP's enterprise wide financial system over the period of 2007 to 2011. The first phase of this conversion impacted supply chain functions and was completed in 2008. The second phase of this conversion includes the finance and accounting functions which was completed in 2009.

1.2 Corporate Structure

The following is the legal corporate structure for Hydro One:



1.3 Common Corporate Cost Allocation and Common Asset Allocation Methodology

Hydro One utilizes a centralized shared services model to deliver its common services. This serves as the most economic approach. Accordingly, common services are provided to the Transmission and Distribution businesses of Hydro One Networks and to other Hydro One subsidiaries on a centralized basis.

The costs of these services and assets are assigned to business units and subsidiaries on the basis of cost causation. These costs and assets are directly assigned where it is possible to do so. All other costs are allocated based on cost drivers, direct benefits or other methods as appropriate.

The Common Corporate Costs OM&A programs include the provision of Corporate Common Functions and Services ("CCF&S"), Asset Management, Information Management Services, and Operating programs to support the Hydro One Networks Distribution and Transmission business.

Similar to the common corporate costs, Hydro One has been able to maximize efficiencies through the centralization of the maintenance, management and purchase of shared assets at the corporate level. These assets include shared land and buildings, telecommunication equipment, computer equipment, applications software, tools and transportation and work equipment ("T&WE").

Hydro One Networks previously commissioned studies to recommend appropriate allocation methods for the assignment of these costs. The study was presented for examination during the Company's 2006 Distribution Rates proceeding, RP-2005-0020/EB-2005-0378 and was accepted by the OEB as an appropriate methodology for allocating costs amongst the subsidiaries and Networks businesses. Updates by B&V to the cost allocation report, specific to the Distribution and Transmission businesses, were accepted by the OEB during the EB-2007-0681 Distribution Rate Proceeding as well as the EB-2006-0501 and EB-2008-0272 Transmission Rate Proceedings. In 2009, B&V reviewed and confirmed that Hydro One applied the OEB-accepted methodology to its Business Plan 2010-2014 data for its 2010/2011 Distribution Rate Filing EB-2009-0096 and its 2011/2012 Transmission Rate Filing EB-2010-0002, and the results reflect a consistent allocation of these common corporate costs and shared assets; this was accepted by the OEB in its Decisions in those proceedings.

2.0 Scope of Work

2.1 Vision

Hydro One is conducting a selection process for an external consulting firm to conduct a common cost allocation study and a common asset allocation study. In addition, Hydro One will require the successful proponent to conduct and prepare an overhead capitalization methodology. The Company is seeking a firm of competent and committed professionals, to provide such studies, as well as the ability to testify to the proposed methodology in an OEB proceeding. Interested parties should include in their submission a proposed timeline that includes milestones and proposed schedule of time spent with Hydro One personnel.

2.2 Project Objective, Mandate and Scope

The ultimate objective of the project is to successfully select an external consultant that will review corporate shared resource levels (both common costs and common assets) and to recommend appropriate cost allocation methodology and rates to meet the requirements of the Company and its subsidiaries, as well as other stakeholders such as the OEB. The proposed methodology must comply with OEB precedent and also comply with relevant provisions of the Affiliate Relationship Code for Electricity Distributors and Transmitters. Therefore, the external consultant should not only be familiar with the regulatory environment but also have experience before regulatory bodies in Ontario or North America.

Hydro One will be preparing a new Business Plan for the 2012 -2016 period that is expected to be approved by the Hydro One Board of Directors in September 2011. This Business Plan will be the basis of the 2012/2013 Distribution rate application which is expected to be submitted to the OEB in the fall of 2011 and the 2013/2014 Transmission rate application which is expected to be submitted to the OEB in Q1 2012. The results of the required study will be used in the preparation of this Business Plan.

The successful proponent should have a reasonable understanding of various financial accounting frameworks and standards including: Pre-Changeover Canadian Generally Accepted Accounting Principles (i.e. CICA Handbook part V), U.S. GAAP, and International Financial Reporting Standards (IFRS). The successful proponent will also have an appreciation for the IFRS modifications that the Ontario Energy Board (OEB) proposes to apply in using this accounting framework in the regulation of Ontario rate regulated enterprises. The OEB EB-2008-0408 report on the transition to IFRS is available on the OEB web site http://www.oeb.gov.on.ca/OEB/_Documents/EB-2008-0408/IFRS_Board_Report_20090728.pdf. Proponents are advised to review previous Hydro One rate applications and applicable studies which can be found at http://www.hydroone.com/RegulatoryAffairs/Pages/Regulatory%20Affairs.aspx

Scope

- Recommend a best practice methodology to distribute Hydro One Inc.'s Common Corporate costs and assets among the business units that use the functions and services. This recommendation could include the continuation of the existing methodology, the continuation of the existing methodology with modifications or the proposal of a new methodology.
- Recommend a best practice methodology to distribute an appropriate amount of Hydro One Inc.'s Common Corporate costs to Capital Expenditures through the overhead capitalization rate. This recommendation could include the continuation of the existing methodology, the continuation of the existing methodology with modifications or the proposal of a new methodology or elimination entirely of an overhead capitalization methodology.
- Prepare a Report of the recommended Common Corporate Costs and Assets Methodology to be used in future rate applications. This report will include a conclusion, definitions, a summary of every factor used in the methodology and the proposed methodology.
- Prepare a Report of the recommended Overhead Capitalization Methodology to be used in future rate applications. This report will include a conclusion, definitions, a summary of every factor used in the methodology and the proposed methodology.
- Identify the functions and services included in the Common Corporate costs
- Identify activities that are performed in order to provide the functions and services included in the Common Corporate costs

- Determine which Common Corporate functions can distribute cost directly, which units can have cost distributed using time studies and which units require allocations using drivers and why.
- Propose and analyze all drivers used for allocation.
- Propose, analyze and perform all time studies required.
- Distribute the 2012, 2013 and 2014 budgeted cost to perform each function and service among the activities required to perform it, based on time and/or cost studies
- Distribute the cost of each activity among the business units based on direct assignment when possible, and based on cost drivers when not
- Prepare a report documenting the overhead capitalization methodology that has been developed which will attribute Common Corporate costs to capital expenditures for both the Distribution and Transmission businesses for each of 2012, 2013 and 2014.
- Prepare responses to Interrogatories from Intervenors during a rate application relating to the proposed Cost Allocation methodology.
- Be available to testify to the proposed methodology during a future rate application.
- The deadline for the completion of the methodologies is June 30th, 2011.
- The immediate deliverable for the end of June is a review of the current methodologies with an update reflecting currently available data.
- Final reports for Common Corporate costs allocation, Common Corporate assets allocation and Overhead Capitalization Methodology reflecting the current Business Plan and including both the Distribution and Transmission businesses in the same report, to be completed by the beginning of October 2011, in order to be submitted in Cost of Service applications.

In support of the successful Proponent’s work, Hydro One’s management will respond to all requests for basic information and/or supporting documentation.

<u>Expectations:</u>

Hydro One management expects a high quality engagement team with substantial knowledge and experience in the regulated electricity industry. We also expect that the engagement partner selected to serve Hydro One is a senior member of the firm, capable of committing the firm. Consequently, resumes of the proposed engagement team should be included with the proposal and the key members of the engagement team should attend the presentation. It is also expected that additional resources will be available beyond the engagement team, as needed.

Hydro One management expects to be served by a firm that has professional credibility in Hydro One’s industry and knowledge of the issues affecting Hydro

One. A representative list of clients in Hydro One's industry, including the types of services rendered, should be provided. Firm wide expertise and local expertise should be differentiated.

Hydro One management expects to pay competitive fees for external consultation services. The annual fee quote should include estimates for routine, out-of-pocket expenses. Consulting hours by area, professional level, and average billing rates should be included in the proposal. Please also outline the circumstances and processes for adjustment to the base fee. Competitive flat fee structures are required.

Hydro One expects that the successful Proponent will have relevant experience in performing and/or testifying to cost allocation studies that have been used by regulated entities either in Ontario or North America. The proponent will also have relevant experience and knowledge of regulatory accounting.

Consumers Council of Canada (CCC) INTERROGATORY #27 List 1

Issue 8 **Are the methodologies used to allocate Shared Services and Other O&M costs to the transmission business and to determine the transmission related overhead capitalization rate for 2013/2014 appropriate?**

Interrogatory

(Ex. C1/T1/S1/p. 6) The evidence indicates that in 2102 HONI retained Black and Veatch to review the methodology to allocate common costs among the business entities. Has HONI considered retaining an independent consultant other than B&V to· review the methodology. If not, why not? Was the B&V work tendered?

Response

Hydro One released a Request For Proposal (RFP) as part of the process of selecting an independent consultant to review the common cost allocation methodology. All responses to the RFP were considered.

Ontario Energy Board (Board Staff) INTERROGATORY #47 List 1

Issue 9 **Are the amounts proposed to be included in the 2013 and 2014 revenue requirements for income and other taxes appropriate?**

Interrogatory

Ref: Exhibit C2/Tab5/Sch1 and Exhibit C2/Tab5/Sch2
Hydro One filed the calculation of 2009, 2010, 2013, and 2014 utility income tax at Exhibit C2/Tab 5/Schedule 1.

a) Please provide the calculation of 2011 and 2012 utility income tax and supporting schedules. Please reconcile the 2011 and 2012 utility income tax to the amounts approved in EB-2010-0002.

b) Please disclose any significant changes that Hydro One Transmission has incorporated into its 2013 and 2014 utility income tax calculation compared to its last rebasing proceeding, EB-2010-0002. Please compare Hydro One's proposed methodology in EB-2012-0031 to the methodology that was approved by the Board in EB-2010-0002. The changes should include but not limited to the:

i. impact from the transition to USGAAP;
ii. CCA class changes for Hydro One's existing capital assets;
iii. CCA rate changes for Hydro One's existing capital assets; and
iv. CCA class and rates chosen for the capital assets additions in 2013 and 2014.

Response

a) Please see EB 2012-0031 Exhibit C2, Tab 5, Schedule 3, Attachments 2-4 for the 2011 utility income tax and supporting schedules, submitted August 15, 2012. See attached schedule for 2012 pro-forma calculation of utility income tax.

A reconciliation between actual and pro-forma utility taxes to income taxes calculated for revenue requirement cannot be done. Under the taxes payable method, no provision is made for future income taxes that result from timing differences between the tax basis of assets and liabilities and their carrying amounts for accounting purposes. Accordingly, the taxes payable method will result in the PILs income tax payable being different from the amount that would have been recorded, had the combined Canadian Federal and Ontario statutory income tax rate been applied to the regulatory net income before tax. When unrecorded future income taxes become payable, it is expected that they will be included in the rates approved by the Board and recovered from customers at that time.

b) Hydro One's proposed methodology in EB-2012-0031 is similar to that approved by the Board in EB-2010-0002 and there are no significant changes since the last proceeding.

HYDRO ONE NETWORKS INC.
TRANSMISSION
Calculation of Utility Income Taxes
Bridge Year 2012
Year Ending December 31
($ Millions)

Line No.	Particulars		2012
	Calculation of Federal and ON Taxable Income		
1	Net Income Before Tax (NIBT)	$	440.7
2	**Required Adjustments to accounting NIBT**		
3	**Recurring items included in Revenue Requirement (RR):**		
4	Other Post Employment Benefit expense		23.8
5	Other Post Employment Benefit payments		(22.4)
6	Depreciation and amortization		337.1
7	Capital Cost Allowance		(445.5)
8	Removal costs		(0.8)
9	Environmental costs paid		(6.2)
10	Non-deductible items (50% Meals & entertainment / interest)		3.5
11	R & D Fed ITC/ Apprenticeship (prior yr addback)		0.4
12	Ontario hiring credits (Co op & Apprentice)		2.5
13	Capitalized overhead costs deducted		(27.1)
14	Pension cost deductions		(38.9)
15		$	(173.6)
16	**Reversal of accounting adjustments not part of RR:**		
17	Capitalized interest deductible for tax		(48.3)
18		$	(48.3)
19	**Recurring items not part of RR:**		
20			
21	Cumulative Eligible Capital		(4.0)
22		$	(4.0)
23	**Immaterial items not in business plan detail:**		
24	Capital additions deducted for accounting		1.2
25	Net Underwriting/Finance costs		0.2
26		$	1.4
27			
28	NET Adjustments to Accounting NIBT	$	(224.5)
29			
30	Taxable Income	$	216.1
31			
32			
34			
35	Taxable Income	$	216.1
36			
37	Corporate Income Tax Rate		27%
38			
39	Subtotal		57.3
40	Less: Tax credits		(2.9)
41	Income Tax	$	54.4

Note: above amounts include Five Nations

Ontario Energy Board (Board Staff) INTERROGATORY #48 List 1

Issue 9 **Are the amounts proposed to be included in the 2013 and 2014 revenue requirements for income and other taxes appropriate?**

Interrogatory

Ref: Exhibit C2/Tab5/Sch1 and Exhibit D1/Tab1/Sch 2
Capital Expenditures on UCC Schedule and Rate Base Schedule

a) Please reconcile the capital expenditures on Exhibit D1/Tab 1/ Schedule 2 of:

- $ 791.8 million for 2011
- $ 1,294.7 million for 2012
- $ 904.1 million for 2013
- $ 1,023.0 million for 2014

to the capital expenditures reported on the respective UCC schedules on Exhibit C2/Tab 5/Schedule 1 of:

- $ 696.8 million for 2011
- $ 1,182.7 million for 2012
- $ 789.5 million for 2013
- $ 902.3 million for 2014

and provide explanations for differences.

b) Please clarify which capital expenditures are the correct numbers.
c) Please update Hydro One's evidence where appropriate (e.g. rate base section or tax provision section of application).

Response

a) The first set of numbers quoted above represents in-service capital additions, the second set of numbers represents UCC net additions. Table 1 below reconciles the in-service capital additions shown in Exhibit D1, Tab 1, Schedule 2 to the amounts in the UCC net additions shown in the schedules in Exhibit C2, Tab 5, Schedule 1. The differences are due to adjustments made to in-service capital additions for income tax purposes, specifically to calculate the Capital Cost Allowance (CCA) claim.

Table 1: Reconciliation of In-Service Additions	**2011**	**2012**	**2013**	**2014**
In-Service Additions per D1-1-2	791.8	1,294.7	904.1	1,023.0
Plus: Asset removal costs	19.0	20.2	25.8	32.8
Less: Interest capitalized	(45.4)	(49.0)	(47.2)	(50.1)
Less: Overheads capitalized	(25.4)	(28.3)	(27.3)	(27.3)
Less: Depreciation capitalized	(10.1)	(9.0)	(9.5)	(9.7)
Less: OPEB Capitalized	(13.6)	(19.7)	(24.1)	(27.8)
Less: Pension Capitalized	(19.5)	(26.2)	(32.3)	(38.6)
UCC Net Additions per C2-5-1	**696.8**	**1,182.7**	**789.5**	**902.3**

Adjustments to UCC additions are based on an audit agreement with the Ministry of Finance; whereby deductions to arrive at taxable income that pertain to fixed asset amounts capitalized for accounting reduce additions to UCC on a straight line basis over a 3 year period. In the case of removal costs expensed for accounting purposes relating to capital additions for tax purposes, these are added back via depreciation to arrive at taxable income (an increase in taxable income) and result in an increase in UCC adds over 3 years.

b) The in-service capital additions is correct for the purpose of property, plant and equipment in service and the UCC net additions is correct for the purpose of calculating capital cost allowance.

c) No updates are required as the in-service capital additions and UCC net additions are correct throughout the evidence.

Ontario Energy Board (Board Staff) INTERROGATORY #49 List 1

Issue 9 **Are the amounts proposed to be included in the 2013 and 2014 revenue requirements for income and other taxes appropriate?**

Interrogatory

Ref: Exhibit C2/Tab5/Sch1 and Exhibit C1/Tab8/Sch1
Depreciation and Amortization Expense and Calculation of Utility Income Taxes

a) Please reconcile the depreciation and amortization expenses on Exhibit C1/Tab 8/Schedule 1 of:
   - $340.4 million (depreciation) and $8.5 million (amortization) for 2013
   - $367.7 million (depreciation) and $9.3 million (amortization) for 2014

   to the depreciation and amortization expenses reported on the respective calculation of utility income taxes schedules on Exhibit C2/Tab 5/Schedule 1 of:
   - $346.7 million for 2013
   - $374.7 million for 2014

and provide explanations for differences.

b) Please clarify which depreciation and amortization expenses are the correct numbers.

c) Please update Hydro One's evidence where appropriate (e.g. depreciation/amortization section or tax provision section of application).

Response

a) Please refer to Exhibit C2, Tab 4, Schedule 1 for a line-by-line breakdown of the 2013 and 2014 depreciation and amortization expense shown in Exhibit C2, Tab 5, Schedule 1. The variance of $2.3M in 2013 and 2014 represents the amortization of Regulatory Assets, which is not eligible for recovery through the Transmission Tarriff.

b) The amounts shown in Exhibit C1, Tab 8, Schedule 1 are the correct depreciation and amortization amounts for rate setting purposes. The amounts shown in Exhibit C2, Tab 4, Schedule 1 are the correct depreciation and amortization amounts for income tax purposes.

c) No updates are required as the depreciation and amortization amounts are consistent throughout evidence.

London Property Management Association (LPMA) INTERROGATORY #15 List 1

Issue 9 Are the amounts proposed to be included in the 2013 and 2014 revenue requirements for income and other taxes appropriate?

Interrogatory

Ref: Exhibit C1, Tab 4, Schedule 7

a) Please provide the most recent year-to-date costs incurred for 2012 and the corresponding figure for 2011 in the same level of detail as shown in Table 1.

b) Please provide the calculations that underpin the figures shown in Table 2 for each of years shown, include the number of square meters to which the $86.11 figure applies, the total assessed values and the tax rates applied to those assessed values, along with any other calculations used for additional property tax payments as noted on page 3.

c) What assumptions has Hydro One used for the increase in average tax rates for 2012, 2013 and 2014 that get applies to the assessed values? What was the average increase in tax rates that applies in 2009, 2010 and 2011?

Response

in $M	**2011 Q2 YTD**	**2012 Q2 YTD**
Property Tax	30.1	27.1
Indemnity Payment	2.3	2.3
Rights Payment	0.5	0.2
Total	**32.9**	**29.6**

a) The property tax payments forecast for bridge year 2012 and test years takes into consideration 2011 actual property tax expense and applies factors driving the forecasted annual increase in property taxes of 2% as result of increases in assessed value of Hydro One properties and 2% annual increase due to municipal tax increases.

b) The funding forecast for bridge year 2012 and test years 2013 and 2014 are based on the following assumptions:

- An annual 2% municipal tax increase
- Assumes increases in property taxes of 2% for 2012 and 2% for each test year as result of re-assessment.
- Assumes no legislative or other tax changes (including changes to municipal assessments) relative to Hydro One properties.

c) The assumptions used above take into consideration province wide provincial reassessment program impacting 2013 tax year and beyond.

The average municipal tax increase between years 2009-2010 was approximately 5.8% and 4% between years 2010-2011.

London Property Management Association (LPMA) INTERROGATORY #16 List 1

Issue 9 Are the amounts proposed to be included in the 2013 and 2014 revenue requirements for income and other taxes appropriate?

Interrogatory

Ref: Exhibit C1, Tab 4, Schedule 7

a) Please provide an update on the status of the rights payments associated with the railway companies that are currently under review. In particular, have new agreements been reached?

b) Please provide the actual payments associated with the rights payments to railway companies made in 2009, 2010, 2011 and, if available, for 2012.

c) Please provide the actual payments associated with the First Nations rights payments made in 2009, 2010, 2011 and, if available, for 2012.

Response

a) Hydro One continues to negotiate but has not reached a new agreement to date related to the real estate rights and ultimately costs associated with the rights payments with railway companies.

b) The actual payments made to railways companies in historic years 2009 – 2011 are approximately $0.5M each year.

c) The First Nations Rights payments were approximately $0.8M in 2009, $0.8M in 2010 and $1.1M in 2011.

London Property Management Association (LPMA) INTERROGATORY #17 List 1

Issue 9 **Are the amounts proposed to be included in the 2013 and 2014 revenue requirements for income and other taxes appropriate?**

Interrogatory

Ref: Exhibit C2, Tab 5, Schedule 1, Attachment 2

Please confirm that the reduction to the CCA for Five Nations of $0.3 million is because Hydro One has not included the assets related to this CCA in rate base. Please also confirm that Hydro One has not included any OM&A costs associated with theses assets in the revenue requirement.

Response

Hydro one has excluded, from the rate base, the Five Nations assets and any OM&A costs associated with the assets related to the $0.3 million reduction in CCA.

London Property Management Association (LPMA) INTERROGATORY #18 List 1

Issue 9 Are the amounts proposed to be included in the 2013 and 2014 revenue requirements for income and other taxes appropriate?

Interrogatory

Ref: Exhibit C2, Tab 5, Schedule 1, Attachment 4

Please confirm that the 2011 CCA figures shown in the updated evidence reflect the actual 2011 tax filing.

Response

Ref: Exhibit C2, Tab 5, Schedule 1, Attachment 4, page 2

The 2011 CCA figures shown in the updated evidence reflects the actual 2011 tax filing; see Exhibit C2, Tab 5, Schedule 3, Attachment 3, filed August 15, 2012.

London Property Management Association (LPMA) INTERROGATORY #19 List 1

Issue 9 Are the amounts proposed to be included in the 2013 and 2014 revenue requirements for income and other taxes appropriate?

Interrogatory

Ref: Exhibit C2, Tab 5, Schedule 1, Attachment 5

Please expand the table shown to include actual data for 2011, consistent with the 2011 tax filing, along with the forecast for 2012.

Response

Ref: Exhibit C2, Tab 5, Schedule 1, Attachment 6

The 2011 actual and 2012 estimated tax credits are shown in the table below:

($ Thousands)

	2009 Actual	2010 Actual	2011 Actual	2012 Estimate
ON Coop Education Credit	$621	$834	$690	$600
Eligible positions	235	280	230	200
ON Apprenticeship Credit	$1,825	$2,454	$3,127	$2,180
Eligible positions	224	277	341	242
Federal Apprenticeship Credit	$299	$317	$342	$260
Eligible positions	151	160	177	132
SR&ED (FED/ON)	$374	$840	$1,327	$1,200
TOTAL TAX CREDIT	$3,119	$4,445	$5,486	$4,240

Note: The 2012 apprentice and co-op credit estimate is based on the 2010/2011 weighted average, using a 47% Transmission allocation instead of 60% used in prior years. This properly reflects the underlying program salary estimates for Transmission instead of a capital expenditure proportion previously used.

London Property Management Association (LPMA) INTERROGATORY #20 List 1

Issue 9 Are the amounts proposed to be included in the 2013 and 2014 revenue requirements for income and other taxes appropriate?

Interrogatory

Ref: Exhibit C2, Tab 5, Schedule 1, Attachment 4 & Exhibit C2, Tab 5, Schedule 3, Attachment 4

a) Please explain the decrease in the number of transmissions positions eligible for the Ontario apprenticeship tax credit from 341 in 2011 to 210 in 2013 and 2014.

b) Please explain the decrease in the average value of the transmission related Ontario apprenticeship tax credit from $9,170 in 2011 to $$7,619 in 2013 and 2014.

c) Please explain the decrease in the number of transmission positions eligible for the federal apprenticeship tax credit from 177 in 2011 to 140 in 2013 and 2014.

d) Please explain the significant drop in the transmission SR&ED tax credit from $1,327,232 in 2011 to $350,000 in 2013 and 2014.

Response

Ref: Exhibit C2, Tab 5, Schedule 1, Attachment 5 & Exhibit C2, Tab 5, Schedule 3, Attachment 4

a) Please see response to Interrogatory Exhibit I, Tab 9, Schedule 2.06 LPMA 19 for revised assumptions relating to 2012 and subsequent years. Revised estimates for 2013 and 2014 are reflected in the table below. The final rate orders will reflect the revised amounts.

b) Revised estimate using $9,170 is reflected in the table below.

c) See a) above

d) Revised amounts below reflect Federal changes in 2013/2014; 80% of arms length contract payments apply in 2013. In addition, 2014 also reflects a decrease in rate from 20% to 15%.

($ Thousands)

	2013	**2014**
ON Coop Education Credit	$600	$600
Eligible positions	200	200
ON Apprenticeship Credit	$2,220	$2,220
Eligible positions	242	242
Federal Apprenticeship Credit	$260	$260
Eligible positions	132	132
SR&ED (FED/ON)	$1,125	$845
TOTAL TAX CREDIT	**$4,205**	**$3,925**

London Property Management Association (LPMA) INTERROGATORY #21 List 1

Issue 9 Are the amounts proposed to be included in the 2013 and 2014 revenue requirements for income and other taxes appropriate?

Interrogatory

Ref: Exhibit C2, Tab 5, Schedule 1, Attachment 2 & Exhibit D1, Tab 1, Schedule 2

Please reconcile the additions to CCA for both 2013 and 2014 shown in Attachment 2 of Exhibit C2, Tab 5, Schedule 1 with the in-service capital additions shown in Table 1 of Exhibit D1, Tab 1, Schedule 2. Please provide a detail explanation for any non-land differences.

Response

Please see response to interrogatory Exhibit I, Tab 9, Schedule 1.02 Staff 48 for a reconciliation of in-service capital additions to CCA additions and an explanation of the differences

London Property Management Association (LPMA) INTERROGATORY #22 List 1

Issue 10 **Is Hydro One Networks' proposed depreciation expense for 2013 and 2014 appropriate?**

Interrogatory

Ref: Exhibit C1, Tab 8, Schedule 1

What is the impact in each of 2013 and 2014 of the new depreciation rates, as compared those currently being utilized in 2012?

Response

As shown in Exhibit E1, Tab 1, Schedule 1 Table 3, the net impact of the new depreciation rates is a reduction in rates revenue requirement of $33.2M in 2013. Because the new rates are already in effect in 2013, the incremental reduction in rates revenue requirement as a result of the new depreciation rates is $0.9M in 2014.

Ontario Energy Board (Board Staff) INTERROGATORY #50 List 1

Issue 11 **Are the amounts proposed for rate base in 2013 and 2014 appropriate?**

Interrogatory

Ref: Exhibit D1/Tab1/Sch1/p 2/Table 1 Transmission Rate Base
Please expand the table at the above reference to include the years 2009 to 2012. For the years 2009 to 2011 please provide actual data and for the year 2012 please provide the Bridge Year Forecast.

Response

Table 1.
Transmission Rate Base ($ Millions)

Description	**Actual 2009**	**Actual 2010**	**Actual 2011**	**Bridge 2012**	**Test 2013**	**Test 2014**
Gross Plant	10,781.3	11,504.7	12,307.5	13,311.6	14,368.2	15,293.7
Accumulated Depreciation	(3,966.7)	(4,191.3)	(4,436.5)	(4,703.3)	(4,981.0)	(5,267.4)
Net Plant in Service	6,814.7	7,313.4	7,871.0	8,608.3	9,387.2	10,026.4
Construction work in progress	0.0	0.0	0.0	0.0	0.0	0.0
Net Utility Plant	**6,814.7**	**7,313.4**	**7,871.0**	**8,608.3**	**9,387.2**	**10,026.4**
Cash Working Capital (Note 1)	9.4	8.6	7.1	5.0	12.5	11.7
Materials and Supplies Inventory	11.7	12.5	14.4	15.2	13.7	12.9
Total Working Capital	**21.1**	**21.0**	**21.4**	**20.2**	**26.3**	**24.6**
Transmission Rate Base	**6,835.8**	**7,334.4**	**7,892.5**	**8,628.5**	**9,413.5**	**10,050.9**

Note 1: Cash Working Capital Allowance for 2009 to 2012 is stated as OEB approved amounts as per OEB rate order.

Ontario Energy Board (Board Staff) INTERROGATORY #51 List 1

Issue 11 Are the amounts proposed for rate base in 2013 and 2014 appropriate?

Interrogatory

Ref: Exhibit D1/Tab1/Sch1/p 3/Table 2 Continuity of Fixed Assets
With respect to the table referenced above, please elaborate on the reasons for the elimination of $11 million from "Transfers", in the August 15th update compared to the May 28th filing.

Response

The $11 million amount in the transfer column Exhibit D1, Tab1, Schedule 1, p 3, table 2 in 2012 represents a reclassification of materials and supplies inventory that was initially classified as strategic spares inventory. The offset to this transfer was to the short-term materials and supplies amount in Exhibit D1, Tab 5, Schedule 1, p 2, table 1.

Ontario Energy Board (Board Staff) INTERROGATORY #52 List 1

Issue 11 Are the amounts proposed for rate base in 2013 and 2014 appropriate?

Interrogatory

Ref: Exhibit D1/Tab1/Sch2/p 1/Table 1 – In-Service Capital Additions 2011 - 2014

Please expand the table at the above reference and provide the actual in-service capital additions and the Board approved in-service capital additions for the years 2007 to 2010. In the table at the above reference, the estimate for the 2012 Bridge Year is noted as "projected". Please clarify if the bridge year estimate is a "year to date" estimate (i.e. actual plus forecast) or a 12 month forecast.

Response

	2007	2007	2008	2008	2009	2009	2010	2010	2011	2011	2012 -	2012 -	2013	2014
	ISA Actuals	**Board Approved**	**ISA Actuals**	**Board Approved**	**ISA Actuals**	**Board Approved**	**ISA Actuals**	**Board Approved**	**ISA Actuals**	**OEB Approved**	**Bridge Projected**	**OEB Approved**	**Test Years**	
Sustaining	198.2	267.1	123.3	301.3	290.2	315.7	351.9	319.5	363.8	363.0	405.3	394.5	497.3	706.2
Development	253.1	179.5	157.2	157.5	247.0	347.9	440.3	503.6	374.6	378.2	814.4	1,074.8	301.8	205.8
Operations	10.4	16.7	5.3	19.4	23.8	19.6	20.5	24.2	6.8	41.0	18.8	52.7	45.1	48.0
Other	28.1	27.4	122.7	99.6	100.3	110.8	30.5	90.5	46.7	52.3	56.1	69.9	59.8	63.1
Total	**489.8**	**490.8**	**408.5**	**577.8**	**661.3**	**794.1**	**843.2**	**937.8**	**791.8**	**834.4**	**1,294.7**	**1,591.9**	**904.1**	**1,023.0**

In Exhibit D1, Tab1, Schedule 2, page 1, Table 1, the bridge year estimate is based on six-month actual in-service additions from January 1 to June 30, 2012, plus six-month forecast for the remainder of the year.

Ontario Energy Board (Board Staff) INTERROGATORY #53 List 1

Issue 11 Are the amounts proposed for rate base in 2013 and 2014 appropriate?

Interrogatory

Ref: Exhibit D1/Tab1/Sch2/p 1/Table 1 – In-Service Capital Additions 2011 – 2014; Board Staff Interrogatory #64 EB-2010-0002
The in-service additions in 2011 were $43 million lower than Board Approved and are projected to be $297 million lower than Board Approved in 2012.

a) In its response to Board staff Interrogatory#64 (a&b) in EB-2010-0002, Hydro One provided a list of projects that were to be placed in-service in 2011 and 2012. Using that same list, please identify the projects that are/may be delayed and will not be in service in 2011/2012. With respect to the projects under $3 million, please provide as a total. With respect to each of the delayed projects, please provide: (i) The original planned in-service; (ii) The new in-service date; (iii) The Board approved capital expenditure; (iv) Actual capital expenditures incurred in 2011 and/or 2012; (v) If additional capital expenditures are proposed in 2013 and/or 2014, please provide the expenditures by year. Please provide the capital expenditures in the form of amounts (i.e. net costs) that will be added to rate base. Please reconcile your answer with the variances noted in the preamble above and with the variance analysis presented at Exhibit D1/Tab1/Sch2/pp 1 - 4.

b) With regard to projects that may have been delayed and are not going to be in-service in 2011 or 2012 as originally planned, how does Hydro One propose to correct for the fact that its 2011 and 2012 rate base may contain costs of projects that are not currently used and useful?

Response

a) Please find the requested tables (Table 1, 2, 3, 4) that includes a breakdown of all capital programs, for Sustaining, Development, Operations and Shared Services that were included in the Exhibit I, Tab 1, Schedule 64 in EB-2010-0002 that are delayed and may not be fully in service in 2011/2012.

Table 1
Delayed Sustainment Projects from EB-2010-0002

in $M

		EB-2010-0002	EB-2012-0031	EB-2010-0002		EB-2012-0031			
ISD#	**Investment Summary Description**	**Original I/S Date**	**New I/S Date**	**2011 ISA Board Approved**	**2012 ISA Board Approved**	**2011 ISA Actual**	**2012 ISA Forecast**	**2013 ISA Forecast**	**2014 ISA Forecast**
S4	Beck #1 SS: Air Blast Circuit Breaker (ABCB) Re-Investment	2012	2017	21.0	13.3	-	-	-	-
S5	Abitibi Canyon Switching Station (SS) and Pinard Transformer Station (TS) - Replace EOL Components	2012	2013	9.0	11.0	-	-	46.0	-
S7	Orangeville TS: Air Blast Circuit Breaker (ABCB) Re-Investment	2013	2014	6.5	6.7	-	17.2	-	10.9
S8	Richview TS 230 kV Switchyard: Air Blast Circuit Breaker (ABCB) Re-Investment	2012	2017	4.4	10.5	-	-	-	-
S9	Hanmer TS 500 kV ABCB Replacement	2012	2013	7.3	9.0	0.3	0.0	25.8	-
S10	Pickering A switchyard : Air Blast Circuit Breaker (ABCB) Re-Investment	2012	2014	2.6	3.7	2.5	1.1	-	2.3
S11	Merival GIS ITE Bus Replacement	2012	2013	5.5	6.8	-	-	11.0	-
S14	Replace EOL CGE Transformers	2012	2013	27.7	30.0	36.5	27.4	9.1	-
S21	BSPS Replacement of End-of-Life Equipment	2012	2014	-	18.1	0.1		-	34.6
S22	ITC - Line Protections Replacements	2012	2015	4.2	5.2	-	-	2.5	2.5
S23	NYPA Tie Lines - Beck Line Protections Replacements	2012	2015	2.8	3.7	-	-	8.3	-
S31	TDCN Cyber Security	2012	2013	-	10.1			10.4	
Total				91.0	127.8	39.3	45.7	113.1	50.3
	Net Work Delayed			51.7	82.1				

Table 2
Delayed Development Projects from EB-2010-0002

in $M

		EB-2010-0002	EB-2010-0002	EB-2010-0002	EB-2012-0031	EB-2010-0002		EB-2012-0031			
ISD#	**Investment Summary Description**	**Cat**	**Green**	**Original I/S Date**	**New I/S Date**	**2011 ISA Board Approved**	**2012 ISA Board Approved**	**2011 ISA Actual**	**2012 ISA Forecast**	**2013 ISA Forecast**	**2014 ISA Forecast**
D11	Toronto Area Station Upgrades for Short Circuit Capability: Rebuild Hearn SS	2	Green	2012	2013	-	83.7			99.9	4.0
D12	Toronto Area Station Upgrades for Short Circuit Capability: Leaside TS Equipment Update	2	Green	2012	2014	-	36.9			18.8	5.1
D18	South Halton Tremaine TS: Build New Transformer Station	2		2012	2013	-	9.3			18.8	
D26	Barwick TS: Build new Transformer Station	2		2012	2013	-	15.3			23.4	
D30	Chatham Wind Generation Connection (260MW)	2		2012	2013	-	-				
D31	Lower Mattagami Generation Connections	4		2012	2013	-	-			1.7	
D37	In-Line Circuit Breakers #1 (Item #4 in Schedule B)	2	Green	2012	2013	-	20.0			20.4	
D38	In-Line Circuit Breakers #2 (Item #4 in Schedule B)	2	Green	2012	2013	-	20.0			21.9	
	Other Capital Projects					4.4	23.5	32.9	7.2		
Total						4.4	208.6	32.9	7.2	204.9	9.1
	Net Work Delayed					(28.5)	201.4				

Table 3
Delayed Operations Projects from EB-2010-0002

		EB-2010-0002	EB-2012-0031	EB-2010-0002		EB-2012-0031			
ISD	**Investment Summary Description**	**Original I/S Date**	**New I/S Date**	**2011 ISA Board Approved**	**2012 ISA Board Approved**	**2011 ISA Actual**	**2012 ISA Forecast**	**2013 ISA Forecast**	**2014 ISA Forecast**
O1	Network Operations Buildings	2012	2015	9.8	8.9	0.2	-	4.2	1.2
O2	NMS Upgrade & Enhancements	2012	2015	3.7	3.9	0.2	0.6	1.4	14.6
O3	Tx Operating Facilities Sustainment	2012	2012-2014	6.3	3.4	1.4	7.0	2.0	0.6
O4	Hub Site Management Program	2012	2014	2.8	4.1	0.8	3.3	-	6.5
O5	Telemetry Expansion	2012	2012-2014	3.3	3.4	0.5	1.6	-	4.6
O6	Wide Area Network	2011-21014	2015	10.7	24.2	0.5	-	16.6	3.6
Total				36.5	47.8	3.6	12.5	24.2	31.1
	Net Work Delayed			32.9	35.3				

Table 4
Delayed Shared Services Projects from EB-2010-0002

ISD	Investment Summary Description	EB-2010-0002 Original I/S Date	EB-2012-0031 New I/S Date	EB-2010-0002 2011 ISA Board Approved	EB-2010-0002 2012 ISA Board Approved	EB-2012-0031 2011 ISA Actual	EB-2012-0031 2012 ISA Forecast	EB-2012-0031 2013 ISA Forecast	EB-2012-0031 2014 ISA Forecast
IT2	Cornerstone Phase 3	2012	2011 - 2014	(8.4)	21.6	8.6	10.1	10.6	12.4
IT3	Mobile IT Platform	2011	2010 - 2014	1.6	1.1	1.0	2.8	-	0.6
Total				(6.8)	22.7	9.6	12.9	10.6	12.9
	Net Work Delayed			(16.4)	9.8				

Attached below is a reconciliation of Tables 1, 2 3 and 4 with the variance calculated in Exhibit D1, Tab1, Schedule 2, Table 1.

		2011 ISA ($M) Actual	2012 ISA ($M) Forecast
Sustainment	**EB-2010-0002 Board Approved**	363.0	394.5
	OEB Approved Net Work Delayed (as per Table 1)	-51.7	-82.1
	Changes to Work Program	52.5	92.9
	EB-2012-0031 Total Sustainment	**363.8**	**405.3**
Development	**EB-2010-0002 Board Approved**	378.2	1074.8
	OEB Approved Net Work Delayed (as per Table 2)	28.5	-201.4
	Changes to Work Program	-32.1	-59.0
	EB-2012-0031 Total Development	**374.6**	**814.4**
Operations	**EB-2010-0002 Board Approved**	41.0	52.7
	OEB Approved Net Work Delayed (as per Table 3)	-32.9	-35.3
	Changes to Work Program	-1.3	1.4
	EB-2012-0031 Total Operations	**6.8**	**18.8**
Shared Services	**EB-2010-0002 Board Approved**	52.3	69.9
	OEB Approved Net Work Delayed (as per Table 4)	16.4	-9.8
	Changes to Work Program	-22.0	-4.0
	EB-2012-0031 Total Shared Services	**46.7**	**56.1**
Total	**EB-2010-0002 Board Approved**	834.4	1591.9
	OEB Approved Net Work Delayed (as per Table 1,2,3,4)	-39.7	-328.5
	Changes to Work Program	-2.9	31.2
	EB-2012-0031 Total	**791.8**	**1294.7**

b) These variances in projects in-service are seen as normal forecast risks and are a normal part of the regulatory process. Variances in forecast were decreasing from 2008 to 2011. The increase in 2012 is unusual, and relates mainly to customer delays (Barwick TS and Tremaine TS), delays to Hearn SS due to property acquisition issues, advancement of in-service for Duart TS, and lower cost of the Bruce to Milton project as outlined in Exhibit D1, Tab 1, Schedule 2. These variances primarily result from circumstances beyond Hydro One's control and are unusually large for one particular year.

London Property Management Association (LPMA) INTERROGATORY #23 List 1

Issue 11 Are the amounts proposed for rate base in 2013 and 2014 appropriate?

Interrogatory

Ref: Exhibit D1, Tab 2, Schedule 1

a) What is the impact on the figures for each of 2012, 2013 and 2014 of a 10 basis point change in the CWIP account rate?

b) Please explain why it is more appropriate to use the effective rate based on the forecasted average debt portfolio rather than the effective rate based on the forecasted incremental debt required to finance the projects in each year.

Response

a) A 10 basis point change in the CWIP account rate would have the following impact:

Year	Capital Expenditures ($M)
2012	$1.1
2013	$1.0
2014	$1.0

b) Under US GAAP, interest is capitalized based on the cost of borrowing that theoretically could have been avoided had the capital investment not been made. The capitalization rate is calculated with reference to all borrowings outstanding in the period. This is based on the notion that capitalized interest is a theoretically avoidable cost and the US GAAP guidance specifically notes that the practicality of actually paying down the related borrowings in the period should not be taken into consideration. Only where specific debt financing is issued to finance a specific capital program or project is that incremental borrowing rate to be applied as the interest capitalization rate. Hydro One has not in the past issued project-specific financing.

London Property Management Association (LPMA) INTERROGATORY #24 List 1

Issue 11 Are the amounts proposed for rate base in 2013 and 2014 appropriate?

Interrogatory

Ref: Exhibit D1, Tab 3, Schedule 1

Please provide a table similar to Table 2 for each of 2007, 2008, 2009 and 2010 that shows the actual capital expenditures compared to the Board approved levels.

Response

Please refer to Interrogatory Response filed at Exhibit I, Tab 12, Schedule 1.02 Staff 55.

London Property Management Association (LPMA) INTERROGATORY #25 List 1

Issue 11 Are the amounts proposed for rate base in 2013 and 2014 appropriate?

Interrogatory

Ref: Exhibit D1, Tab 5, Schedule 1

a) Please explain the significant increase in the monthly inventory level shown in Table 2 for December, 2011.

b) Please provide the monthly inventory level for as many months as are currently available for 2012.

c) Please explain why the year-end inventory levels shown in Table 1 for 2013 and 2014 are approximately $1.0 million than the year-end levels for 2009 and 2010.

Response

a) The increase in the monthly inventory levels shown in Table 2 for December 2011 is the result of a deferral of a security fencing program. Approximately $3M of security fencing was purchased for projects to be executed in 2011. These projects were subsequently deferred in to 2012, 2013 and 2014. As a result of this deferral, the security fencing was moved into inventory.

b)

2012 Monthly Inventory Levels ($M)					
Jan	**Feb**	**Mar**	**Apr**	**May**	**Jun**
16.1	13.5	13.5	13.5	13.4	13.6

c) The year-end inventory estimates show in Table 1 for 2013 are higher than 2009 and 2010 primarily due to the fencing not expected to be fully utilized until 2014.

<u>Pollution Probe (PP) INTERROGATORY #1 List 1</u>

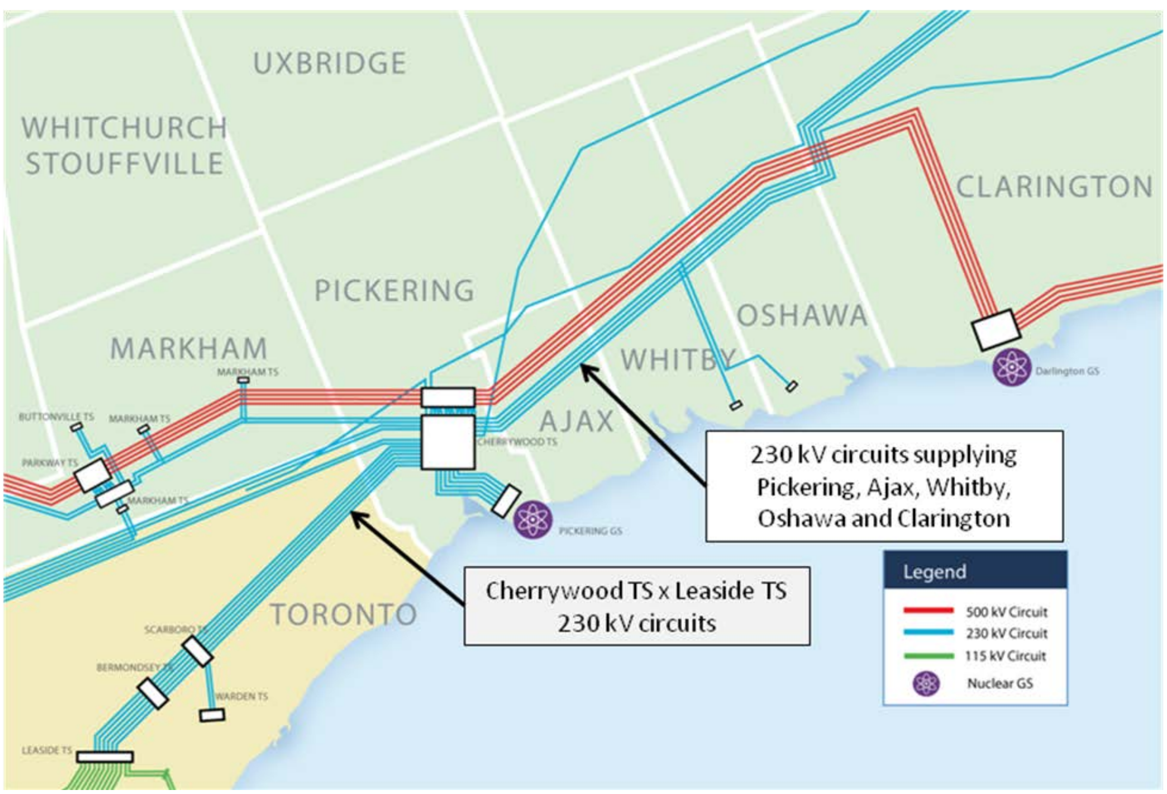
Issue 11 Are the amounts proposed for rate base in 2013 and 2014 appropriate?

Interrogatory

Please provide a map showing the location and boundaries of the eastern part of the Greater Toronto Area ("East GTA") as referenced on page 1 of Appendix B.

Response

The East GTA area boundaries are defined by the electrical system serving the area. As a result, the area does not correspond to specific Regional or Municipal boundaries. The area includes the system supplied from Cherrywood TS to Leaside TS 230 kV circuits (which serves the south-eastern part of Toronto), and the system supplied by the 230 kV circuits emanating east from Cherrywood (which serves the municipalities of Pickering, Ajax, Whitby, Oshawa and Clarington). The below figure identifies the transmission facilities mentioned above.



Source: OPA

Pollution Probe (PP) INTERROGATORY #2 List 1

Issue 11 Are the amounts proposed for rate base in 2013 and 2014 appropriate?

Interrogatory

Please state the annual energy consumption (GWh) and annual peak demand (MW) of the East GTA for each of the last ten years.

Response

The annual energy consumption and coincident peak demand for the East GTA is available from 2004 to 2011 and is summarized below:

	2004	2005	2006	2007	2008	2009	2010	2011
Annual Energy (GWh)	17935	18616	18203	18343	17943	17281	17488	17511
Peak (MW)	3088	3241	3433	3226	3011	3080	3168	3317

Source: OPA

Pollution Probe (PP) INTERROGATORY #3 List 1

Issue 11 Are the amounts proposed for rate base in 2013 and 2014 appropriate?

Interrogatory

Please provide a forecast of energy consumption and annual peak demand of the East GTA for each year from 2012 to 2022 inclusive.

Response

A peak demand forecast for the East GTA and a peak demand forecast net of the contributions of conservation and demand management (CDM) targets have been developed and are presented below for the period from 2012 to 2022 inclusive. It shows that most of the growth in the East GTA between 2012 and 2022 is forecast to be met through CDM. Since the need for transmission reinforcements is driven by peak electricity demand, a forecast of energy consumption for the East GTA area has not been developed.

(MW)	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
East GTA- Peak Demand	3334	3395	3460	3520	3579	3639	3694	3749	3808	3866	3924
East GTA- Peak Demand Net of Conservation and Demand Management	3202	3184	3177	3183	3187	3192	3198	3210	3234	3259	3287

Source: OPA

<u>Pollution Probe (PP) INTERROGATORY #4 List 1</u>

Issue 11 Are the amounts proposed for rate base in 2013 and 2014 appropriate?

<u>Interrogatory</u>

According to page 5 of Appendix B: "Installing new generation totalling 1,000 MW close to Cherrywood TS would be required to meet the required supply reliability in the East GTA."

a. Could the required supply reliability also be met by 1,000 MW of conservation and demand management ("CDM")? If no, why not?

b. Could the required supply reliability be met by a combination of 1,000 MW of new generation and of CDM? If no, please explain why not?

<u>Response</u>

a. In theory, a sufficient amount of conservation and demand management in the East GTA could reduce the load to meet the required reliability. As indicated in Exhibit I, Tab 11, Schedule 4.03 PP 3, the load level with the full amount of the targeted conservation and demand management allocated for the area for the 2012 to 2020 period is about 3200 MW. The required 1000 MW additional load reduction is about 30% of the 3200 MW load level. The 3200 MW load level already includes the target conservation and demand management amount of 337 MW by 2015. The OPA believes that relying on achieving an additional 1000 MW (about 3 times more than the full target amount) of conservation and demand management to maintain supply reliability in the East GTA by 2015 would not be a prudent course of action.

b. In theory, a sufficient combination of conservation and demand management and new generation in the East GTA could reduce the load to meet the required reliability. There are interests under the OPA's Combined Heat & Power ("CHP") procurement program of about 300 MW. This procurement program was designed to find the best projects for ratepayers. However, even if all these generation interests are able to obtain OPA contracts under the procurement process and they could be placed in-service all by the required time, 700 MW of additional conservation and demand management would still be required. The OPA believes that relying on achieving 300 MW of uncertain generation and 700 MW of unplanned conservation and demand management to maintain supply reliability in the East GTA would not be a prudent course of action.

Pollution Probe (PP) INTERROGATORY #5 List 1

Issue 11 Are the amounts proposed for rate base in 2013 and 2014 appropriate?

Interrogatory

Please state the number of peaksaver participants in the East GTA and their potential to reduce peak day demand.

Response

The OPA has identified that for the East GTA area, there are currently 36,324 controllable devices (central air conditioners or electric water heaters) participating in the Residential and Small Commercial Demand Response program. The peak demand savings from these devices is approximately 20 MW.

Note: The East GTA area was defined for the purpose of this search as including the following Forward Sorting Areas: M6R, M6K, M6J, M5A, M4M, M4L, M4E, M1N, M5S, M4Y, M4X, M5R, M4W, M4K, M4J, M4C, M4B, M1L, M4V, M4T, M5P, M4S, M5N, M4R, M4P, M5M, M4N, M2P, M2L, M3B, M3A, M1R, M4A, M3C, M4G, M1P, M1K, M1M, M1J, M1H, M1G, M1E, M1C, L1Y, M1X, L1V, L1W, L1S, L1T, L1Z, L1P, L1N, L1R, L1M, L1L, L1J, L1G, L1H, L1K, L1E, L1C, and L1B.

Pollution Probe (PP) INTERROGATORY #6 List 1

Issue 11 Are the amounts proposed for rate base in 2013 and 2014 appropriate?

Interrogatory

Please state the forecast number of peaksaver participants in the East GTA on December 31, 2014 and their forecast potential to reduce peak day demand.

Response

The OPA has not forecasted participation in the Residential and Small Commercial Demand Response program specifically for the East GTA. However, the OPA has forecasted a total of approximately 283 MW of conservation peak demand savings in the East GTA by 2014. This would include savings from the Residential and Small Commercial Demand Response program.

Pollution Probe (PP) INTERROGATORY #7 List 1

Issue 11 Are the amounts proposed for rate base in 2013 and 2014 appropriate?

Interrogatory

Please state the maximum potential number of peaksaver participants in the eastern GTA and their potential to reduce peak day demand.

Response

The OPA has not estimated the maximum potential number of Residential and Small Commercial Demand Response participants in the East GTA and the associated peak demand savings.

Pollution Probe (PP) INTERROGATORY #8 List 1

Issue 11 Are the amounts proposed for rate base in 2013 and 2014 appropriate?

Interrogatory

Please state the Ontario Power Authority's ("OPA") existing non-residential demand response capability (e.g., DR1, DR2, DR3) in the East GTA.

Response

The OPA has identified that the contracted peak demand savings from DR3 participants in the East GTA is approximately 64 MW. There are no DR1 or DR2 participants in the East GTA.

Note: The East GTA was defined for the purpose of this search as including the following Forward Sorting Areas: M6R, M6K, M6J, M5A, M4M, M4L, M4E, M1N, M5S, M4Y, M4X, M5R, M4W, M4K, M4J, M4C, M4B, M1L, M4V, M4T, M5P, M4S, M5N, M4R, M4P, M5M, M4N, M2P, M2L, M3B, M3A, M1R, M4A, M3C, M4G, M1P, M1K, M1M, M1J, M1H, M1G, M1E, M1C, L1Y, M1X, L1V, L1W, L1S, L1T, L1Z, L1P, L1N, L1R, L1M, L1L, L1J, L1G, L1H, L1K, L1E, L1C, and L1B.

Pollution Probe (PP) INTERROGATORY #9 List 1

Issue 11 Are the amounts proposed for rate base in 2013 and 2014 appropriate?

Interrogatory

Has Hydro One and/or the OPA estimated the East GTA's potential for incremental cost-effective energy efficiency programs and cost-effective demand response programs (e.g. in terms of energy in MWhs and peak demand reductions in MW)? If yes, please provide Hydro One's and the OPA's estimates and the studies and analyses that support these estimates.

Response

Neither Hydro One nor the OPA has an estimate of the potential for incremental cost-effective energy efficiency programs and cost-effective demand response programs for the East GTA.

Pollution Probe (PP) INTERROGATORY #10 List 1

Issue 11 Are the amounts proposed for rate base in 2013 and 2014 appropriate?

Interrogatory

Please provide Hydro One's and/or the OPA's estimates of the avoided cost of new electricity supply (kW and kWh) in Ontario for each of the next 10 years, including the costs of generation, transmission, and distribution (i.e. the cost that can be avoided if new electricity supply is not needed). Please provide the studies, analyses and input assumptions that support these avoided cost estimates.

Response

The avoided cost of supply assumptions are detailed in Appendix A of the "*OPA Conservation and Demand Management Cost Effectiveness Guide*", which can be found at(http://www.powerauthority.on.ca/sites/default/files/20110406%20%20EMV%20Protocols%20and%20Requirements.pdf). These assumptions were developed in preparation for the first Integrated Power System Plan filed in 2007 and an updated has not been published since.

The avoided cost table provided by the OPA is on the following page.

Year	Avoided Energy Cost by Season and Time-of-Use Period (2007 $/MWh)								Avoided Capacity Cost (2007 $/kW-yr)			Avoided Natural Gas Cost (2007 $/MMBtu)	Avoided Water Cost	Avoided Propane Cost (2007 $/L)	Avoided Fuel Oil Cost (2007 $/L)
	Winter			Summer			Shoulder		Generation	Transmission	Distribution				
	On Peak	Mid-Peak	Off-Peak	On Peak	Mid-Peak	Off-Peak	Mid-Peak	Off Peak					$/Litre		
2008	$71.48	$68.32	$35.74	$73.41	$59.46	$34.34	$38.23	$29.26	$133.10	$3.40	$4.30	$9.54	$0.00000371	$0.39	$0.47
2009	$68.14	$66.46	$36.19	$67.63	$57.24	$34.04	$39.06	$28.63	$133.10	$3.40	$4.30	$8.65	$0.00000371	$0.36	$0.42
2010	$60.94	$58.53	$62.12	$62.12	$54.57	$34.27	$36.62	$26.75	$133.10	$3.40	$4.30	$8.29	$0.00000371	$0.34	$0.41
2011	$56.93	$53.55	$32.12	$62.47	$52.75	$31.51	$35.04	$26.43	$133.10	$3.40	$4.30	$8.29	$0.00000371	$0.34	$0.41
2012	$57.88	$58.31	$32.49	$62.93	$53.76	$31.83	$33.72	$23.38	$133.10	$3.40	$4.30	$8.29	$0.00000371	$0.34	$0.41
2013	$56.45	$54.56	$30.63	$60.14	$51.49	$30.76	$33.34	$23.07	$133.10	$3.40	$4.30	$8.29	$0.00000371	$0.34	$0.41
2014	$57.04	$55.44	$30.88	$60.67	$51.90	$31.21	$34.98	$25.37	$133.10	$3.40	$4.30	$8.29	$0.00000371	$0.34	$0.41
2015	$66.76	$65.87	$40.19	$71.66	$62.33	$37.61	$48.77	$30.30	$133.10	$3.40	$4.30	$8.29	$0.00000371	$0.34	$0.41
2016	$68.26	$66.48	$44.31	$73.58	$64.74	$38.91	$49.68	$29.95	$133.10	$3.40	$4.30	$8.29	$0.00000371	$0.34	$0.41
2017	$69.25	$66.60	$44.68	$76.17	$67.04	$39.68	$48.67	$30.23	$133.10	$3.40	$4.30	$8.29	$0.00000371	$0.34	$0.41
2018	$70.33	$68.44	$45.01	$75.80	$68.50	$39.73	$51.49	$30.07	$133.10	$3.40	$4.30	$8.29	$0.00000371	$0.34	$0.41
2019	$71.65	$69.54	$45.26	$77.70	$70.77	$41.37	$52.69	$30.98	$133.10	$3.40	$4.30	$8.29	$0.00000371	$0.34	$0.41
2020	$70.12	$65.26	$41.61	$74.22	$66.54	$39.45	$44.80	$31.16	$133.10	$3.40	$4.30	$8.29	$0.00000371	$0.34	$0.41
2021	$70.40	$67.73	$41.88	$74.23	$66.21	$39.28	$54.41	$30.65	$133.10	$3.40	$4.30	$8.29	$0.00000371	$0.34	$0.41
2022	$65.74	$63.65	$37.42	$68.00	$59.75	$35.86	$42.50	$27.31	$133.10	$3.40	$4.30	$8.29	$0.00000371	$0.34	$0.41
2023	$62.43	$59.03	$34.46	$66.78	$57.68	$34.15	$35.83	$25.13	$133.10	$3.40	$4.30	$8.29	$0.00000371	$0.34	$0.41
2024	$61.86	$57.71	$34.73	$67.93	$58.67	$34.86	$35.92	$26.19	$133.10	$3.40	$4.30	$8.29	$0.00000371	$0.34	$0.41
2025	$64.14	$60.61	$35.14	$68.61	$59.11	$34.80	$37.16	$25.76	$133.10	$3.40	$4.30	$8.29	$0.00000371	$0.34	$0.41
2026	$68.27	$65.33	$37.03	$69.93	$61.00	$36.81	$45.58	$27.09	$133.10	$3.40	$4.30	$8.29	$0.00000371	$0.34	$0.41
2027	$71.03	$66.21	$38.71	$72.91	$63.44	$37.98	$46.22	$28.50	$133.10	$3.40	$4.30	$8.29	$0.00000371	$0.34	$0.41
2028	$71.03	$66.21	$38.71	$72.91	$63.44	$37.98	$46.22	$28.50	$133.10	$3.40	$4.30	$8.29	$0.00000371	$0.34	$0.41
2029	$71.03	$66.21	$38.71	$72.91	$63.44	$37.98	$46.22	$28.50	$133.10	$3.40	$4.30	$8.29	$0.00000371	$0.34	$0.41
2030	$71.03	$66.21	$38.71	$72.91	$63.44	$37.98	$46.22	$28.50	$133.10	$3.40	$4.30	$8.29	$0.00000371	$0.34	$0.41
2031	$71.03	$66.21	$38.71	$72.91	$63.44	$37.98	$46.22	$28.50	$133.10	$3.40	$4.30	$8.29	$0.00000371	$0.34	$0.41
2032	$71.03	$66.21	$38.71	$72.91	$63.44	$37.98	$46.22	$28.50	$133.10	$3.40	$4.30	$8.29	$0.00000371	$0.34	$0.41
2033	$71.03	$66.21	$38.71	$72.91	$63.44	$37.98	$46.22	$28.50	$133.10	$3.40	$4.30	$8.29	$0.00000371	$0.34	$0.41
2034	$71.03	$66.21	$38.71	$72.91	$63.44	$37.98	$46.22	$28.50	$133.10	$3.40	$4.30	$8.29	$0.00000371	$0.34	$0.41
2035	$71.03	$66.21	$38.71	$72.91	$63.44	$37.98	$46.22	$28.50	$133.10	$3.40	$4.30	$8.29	$0.00000371	$0.34	$0.41
2036	$71.03	$66.21	$38.71	$72.91	$63.44	$37.98	$46.22	$28.50	$133.10	$3.40	$4.30	$8.29	$0.00000371	$0.34	$0.41
2037	$71.03	$66.21	$38.71	$72.91	$63.44	$37.98	$46.22	$28.50	$133.10	$3.40	$4.30	$8.29	$0.00000371	$0.34	$0.41
2038	$71.03	$66.21	$38.71	$72.91	$63.44	$37.98	$46.22	$28.50	$133.10	$3.40	$4.30	$8.29	$0.00000371	$0.34	$0.41
2039	$71.03	$66.21	$38.71	$72.91	$63.44	$37.98	$46.22	$28.50	$133.10	$3.40	$4.30	$8.29	$0.00000371	$0.34	$0.41
2040	$71.03	$66.21	$38.71	$72.91	$63.44	$37.98	$46.22	$28.50	$133.10	$3.40	$4.30	$8.29	$0.00000371	$0.34	$0.41
2041	$71.03	$66.21	$38.71	$72.91	$63.44	$37.98	$46.22	$28.50	$133.10	$3.40	$4.30	$8.29	$0.00000371	$0.34	$0.41
2042	$71.03	$66.21	$38.71	$72.91	$63.44	$37.98	$46.22	$28.50	$133.10	$3.40	$4.30	$8.29	$0.00000371	$0.34	$0.41
2043	$71.03	$66.21	$38.71	$72.91	$63.44	$37.98	$46.22	$28.50	$133.10	$3.40	$4.30	$8.29	$0.00000371	$0.34	$0.41
2044	$71.03	$66.21	$38.71	$72.91	$63.44	$37.98	$46.22	$28.50	$133.10	$3.40	$4.30	$8.29	$0.00000371	$0.34	$0.41
2045	$71.03	$66.21	$38.71	$72.91	$63.44	$37.98	$46.22	$28.50	$133.10	$3.40	$4.30	$8.29	$0.00000371	$0.34	$0.41
2046	$71.03	$66.21	$38.71	$72.91	$63.44	$37.98	$46.22	$28.50	$133.10	$3.40	$4.30	$8.29	$0.00000371	$0.34	$0.41
2047	$71.03	$66.21	$38.71	$72.91	$63.44	$37.98	$46.22	$28.50	$133.10	$3.40	$4.30	$8.29	$0.00000371	$0.34	$0.41
2048	$71.03	$66.21	$38.71	$72.91	$63.44	$37.98	$46.22	$28.50	$133.10	$3.40	$4.30	$8.29	$0.00000371	$0.34	$0.41
2049	$71.03	$66.21	$38.71	$72.91	$63.44	$37.98	$46.22	$28.50	$133.10	$3.40	$4.30	$8.29	$0.00000371	$0.34	$0.41
2050	$71.03	$66.21	$38.71	$72.91	$63.44	$37.98	$46.22	$28.50	$133.10	$3.40	$4.30	$8.29	$0.00000371	$0.34	$0.41
Source: IPSP Revised Table 3, D-4-1 Attachment 3 contained in GEC IR 28 (I-22-28, p.3) except for subsequent OPA modification to avoided capacity costs Avoided Costs Beyond 2027 are Determined by Extending IPSP Assumptions												Source: IPSP D-3-1 Attachment 4, p.6	Source: Ontario Regulation 450/07	Source: Derived from historical relationship with natural gas costs	

Pollution Probe (PP) INTERROGATORY #11 List 1

Issue 11 Are the amounts proposed for rate base in 2013 and 2014 appropriate?

Interrogatory

Please provide Hydro One's and/or the OPA's estimates of the number of commercial, institutional, multi-residential and industrial diesel back-up generators and their aggregate capacity in the East GTA.

Response

Neither Hydro One nor the OPA has an estimate of the number, or aggregate capacity, of commercial, institutional, multi-residential and industrial diesel back-up generators in the East GTA.

Pollution Probe (PP) INTERROGATORY #12 List 1

Issue 11 Are the amounts proposed for rate base in 2013 and 2014 appropriate?

Interrogatory

Please provide Hydro One's and/or the OPA's estimate of the incremental demand response capability that could be obtained in the East GTA by installing natural gas-fired back-up generators in commercial, multi-residential, institutional and industrial locations that have diesel back-up generators?

Response

Neither Hydro One nor the OPA has an estimate of the incremental demand response capability that could be obtained in the East GTA by installing natural gas-fired back-up generators in commercial, multi-residential, institutional and industrial locations that have diesel back-up generators.

Pollution Probe (PP) INTERROGATORY #13 List 1

Issue 11 Are the amounts proposed for rate base in 2013 and 2014 appropriate?

Interrogatory

Please provide Hydro One's and/or the OPA's estimate of the economic potential for natural gas-fired combined heat and power ("CHP") in the East GTA (i.e. in MW). Please provide the studies, analyses and input assumptions that support these estimates.

Response

The OPA has been carrying out programs for procuring CHP projects under the Ministry of Energy directive. The OPA contracts resulting from these programs have been included in the studies that determine the need for new transmission facilities. The OPA has not carried out a study that determines the economic potential for natural gas-fired CHP from a ratepayer perspective for the East GTA. Rather, the OPA has relied upon the above mentioned procurement process to find the best projects for ratepayers.

Pollution Probe (PP) INTERROGATORY #14 List 1

Issue 11 Are the amounts proposed for rate base in 2013 and 2014 appropriate?

Interrogatory

Please provide a break-out of Hydro One's and/or the OPA's estimate of the economic potential for natural gas-fired CHP in the East GTA for the following sectors: (a) industrial, (b) commercial, (c) institutional, and (d) multi-residential. Please also include a break-out by the following sizes: (a) less than 10 kW, (b) 10 to 50 kW, (c) 51 to 100 kW, (d) 101 to 500 kW, (e) 501 to 999 kW, (f) ito 5 MW, (g) 5.1 to 10 MW, (h) 10.1 to 20 MW, (i) 20.1 to 50 MW, (j) 50.1 to 99 MW, (k) 100 to 200 MW, and (1) greater than 200 MW.

Response

Please see response to Exhibit I, Tab 11, Schedule 4.13 PP 13.

Pollution Probe (PP) INTERROGATORY #15 List 1

Issue 11 Are the amounts proposed for rate base in 2013 and 2014 appropriate?

Interrogatory

Please provide an excel spreadsheet with the electricity demand in the East GTA during every five minute interval in 2011.

Response

A spreadsheet of the hourly East GTA electricity demand for the year 2011 is available in electronic form only (http://www.hydroone.com/RegulatoryAffairs/Pages/2013-2014Tx.aspx). Demand data for every five minute interval is not available.

Pollution Probe (PP) INTERROGATORY #16 List 1

Issue 11 Are the amounts proposed for rate base in 2013 and 2014 appropriate?

Interrogatory

Please state the annual energy consumption (GWh) and annual peak demand (MW) of the South-Central Guelph area for each of the last ten years.

Response

The annual energy consumption and coincident peak demand for the South-Central Guelph area is available from 2004 to 2011 and is summarized below:

	2004	2005	2006	2007	2008	2009	2010	2011
Energy (GWh)	613	631	629	655	648	614	648	654
Peak Demand (MW)	98	110	111	111	107	104	114	117

Source: OPA

Pollution Probe (PP) INTERROGATORY #17 List 1

Issue 11 Are the amounts proposed for rate base in 2013 and 2014 appropriate?

Interrogatory

Please state the forecast energy consumption and annual peak demand of the South-Central Guelph area for each year from 2012 to 2022 inclusive.

Response

A peak demand forecast for the South-Central Guelph area, as well as a peak demand forecast net of the contributions of conservation and existing and contracted distributed generation, have been developed and are presented below for the period from 2012 to 2022 inclusive. These forecasts show that nearly half of the growth in the South-Central Guelph area between 2012 and 2022 will be met through conservation and distributed generation resources.

Since the need for transmission reinforcements is driven by peak electricity demand, a forecast of energy consumption for the South-Central Guelph area has not been developed.

(MW)	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
South-Central Guelph- Peak Demand	124	129	135	144	148	152	156	161	165	168	171
South-Central Guelph- Peak Demand Net of Conservation and Distributed Generation	118	122	125	131	134	136	139	142	145	147	149

Source: OPA

Pollution Probe (PP) INTERROGATORY #18 List 1

Issue 11 **Are the amounts proposed for rate base in 2013 and 2014 appropriate?**

Interrogatory

Please state the number of peaksaver participants in the South-Central Guelph area and their potential to reduce peak day demand.

Response

The OPA has identified that for the Guelph area, there are currently 1,514 controllable devices (central air conditioners or electric water heaters) participating in the Residential and Small Commercial Demand Response program. The peak demand savings from these participants is estimated to be less than 1 MW. The OPA does not have an estimate for participation in the Residential and Small Commercial Demand Response program specifically for the South-Central Guelph area.

Note: The Guelph area has been defined for the purpose of this search as including the following Forward Sorting Areas: N1L, N1C, N1G, N1E, N1H, and N1K.

Pollution Probe (PP) INTERROGATORY #19 List 1

Issue 11 Are the amounts proposed for rate base in 2013 and 2014 appropriate?

Interrogatory

Please provide a forecast number of peaksaver participants in the South-Central Guelph area on December 31, 2014 and their forecast potential to reduce peak day demand.

Response

The OPA has not forecasted participation in the Residential and Small Commercial Demand Response program specifically for the South-Central Guelph area. However, the OPA has forecasted a total of approximately 9 MW of conservation peak demand savings in the South-Central Guelph area by 2014. This would include savings from the Residential and Small Commercial Demand Response program.

Pollution Probe (PP) INTERROGATORY #20 List 1

Issue 11 Are the amounts proposed for rate base in 2013 and 2014 appropriate?

Interrogatory

Please state the maximum potential number of peaksaver participants in the South-Central Guelph area and their potential to reduce peak day demand.

Response

The OPA has not estimated the maximum potential number of Residential and Small Commercial Demand Response participants in the South-Central Guelph area and the associated peak demand savings.

Pollution Probe (PP) INTERROGATORY #21 List 1

Issue 11 Are the amounts proposed for rate base in 2013 and 2014 appropriate?

Interrogatory

Please state the OPA's existing non-residential demand response capability (e.g., DR1, DR2, DR3) in the South-Central Guelph area.

Response

The OPA has identified that the contracted peak demand savings from DR3 participants in the Guelph area is approximately 6 MW. There are no DR1 or DR2 participants in the Guelph area. The OPA does not have an estimate of participation in the DR program specifically for the South-Central Guelph area.

Note: The Guelph area has been defined for the purpose of this search as including the following Forward Sorting Areas: N1L, N1C, N1G, N1E, N1H, and N1K.

Pollution Probe (PP) INTERROGATORY #22 List 1

Issue 11 Are the amounts proposed for rate base in 2013 and 2014 appropriate?

Interrogatory

Has Hydro One and/or the OPA estimated the South-Central Guelph area's potential for incremental cost-effective energy efficiency programs and cost-effective demand response programs (e.g. in terms of energy in MWhs and peak MW demand reductions in MW)? If yes, please provide Hydro One's and the OPA's estimates and the studies and analyses that support these estimates.

Response

Neither Hydro One nor the OPA has an estimate of the potential for incremental cost-effective energy efficiency and cost-effective demand response programs in the South-Central Guelph area.

Pollution Probe (PP) INTERROGATORY #23 List 1

Issue 11 Are the amounts proposed for rate base in 2013 and 2014 appropriate?

Interrogatory

Please provide Hydro One's and/or the OPA's estimates of the number of commercial, institutional, multi-residential and industrial diesel back-up generators and their aggregate capacity in the South-Central Guelph area.

Response

Neither Hydro One nor the OPA has an estimate of the number, or aggregate capacity, of commercial, institutional, multi-residential and industrial diesel back-up generators in the South-Central Guelph area.

Pollution Probe (PP) INTERROGATORY #24 List 1

Issue 11 Are the amounts proposed for rate base in 2013 and 2014 appropriate?

Interrogatory

Please provide Hydro One's and/or the OPA's estimate of the incremental demand response capability that could be obtained in the South-Central Guelph area by installing natural gas-fired back-up generators in commercial, multi-residential, institutional and industrial locations that have diesel back-up generators?

Response

Neither Hydro One nor the OPA has an estimate of the incremental demand response capability that could be obtained in the South-Central Guelph area by installing natural gas-fired back-up generators in commercial, institutional and industrial locations that have diesel back-up generators.

Pollution Probe (PP) INTERROGATORY #25 List 1

Issue 11 Are the amounts proposed for rate base in 2013 and 2014 appropriate?

Interrogatory

Please provide Hydro One's and/or the OPA's estimate of the economic potential for natural gas-fired combined heat and power (CHP) in the South-Central Guelph area (i.e. in MW). Please provide the studies, analyses and input assumptions that support these estimates.

Response

The OPA has been carrying out programs for procuring CHP projects under the Ministry of Energy directive. The OPA contracts resulting from these programs have been included in the studies that determine the need for new transmission facilities. The OPA has not carried out a study that determines the economic potential for natural gas-fired CHP from a ratepayer perspective in the South-Central Guelph area. Rather, the OPA has relied upon the above mentioned procurement process to find the best projects for ratepayers.

Pollution Probe (PP) INTERROGATORY #26 List 1

Issue 11 Are the amounts proposed for rate base in 2013 and 2014 appropriate?

Interrogatory

Please provide a break-out of Hydro One's and/or the OPA's estimate of the economic potential for natural gas-fired CHP in the South-Central Guelph area in the following sectors: (a) industrial, (b) commercial, (c) institutional, and (d) multi-residential. Please also include a break-out by the following sizes: (a) less than 10 kW, (b) 10 to 50 kW, (c) 51 to 100 kW, (d) 101 to 500 kW, (e) 501 to 999 kW, (0 to 5 MW, (g) 5.1 to 10 MW, (h) 10.1 to 20 MW, (i) 20.1 to 50 MW, (j) 50.1 to 99 MW, (k) 100 to 200 MW, and (1) greater than 200 MW.

Response

Please see response to Exhibit I, Tab 11, Schedule 4.25 PP 25.

Pollution Probe (PP) INTERROGATORY #27 List 1

Issue 11 Are the amounts proposed for rate base in 2013 and 2014 appropriate?

Interrogatory

Please provide an excel spreadsheet with the electricity demand in the South-Central Guelph area during every five minute interval in 2011.

Response

A spreadsheet of the hourly South-Central Guelph electricity demand for the year 2011 is available in electronic form only (http://www.hydroone.com/RegulatoryAffairs/Pages/2013-2014Tx.aspx). Demand data for every five minute interval is not available.

Pollution Probe (PP) INTERROGATORY #28 List 1

Issue 11 Are the amounts proposed for rate base in 2013 and 2014 appropriate?

Interrogatory

Please list the members and their affiliations of the Kitchener-Waterloo-Cambridge Guelph Area Working Group. Were any of Hydro One's ratepayer or environmental intervenors invited to join this Working Group? if yes, please provide their names. if no, please explain why not.

Response

In regional planning, the entities officially involved in operating and planning the system are the first parties involved in assessing the needs of an area and developing preliminary alternatives for meeting these needs. Accordingly, the Kitchener-Waterloo-Cambridge-Guelph (KWCG) Area Working Group consists of staff from the Ontario Power Authority, Hydro One Networks Inc., the Independent Electricity System Operator, Kitchener-Wilmot Hydro Inc., Waterloo North Hydro Inc., Cambridge and North Dumfries Hydro Inc., and Guelph Hydro Electric Systems Inc..

In the course of developing a regional plan for the KWCG area, certain pressing supply capacity and other reliability needs were identified that must be addressed in the near-term. The Guelph Area Transmission Reinforcement ("GATR") project will contribute to resolving these near-term needs. The GATR project has been discussed publicly through the Environmental Assessment process, which included Public Information Centres held by Hydro One Networks Inc. that were open to all interested parties.

Additional alternatives to address medium- to longer-term reliability needs in the area will be identified as part of the continuing KWCG regional planning process and discussed through planned engagement in the area. This engagement is planned to take place with First Nations and Métis communities, as well as interested stakeholders (including any of Hydro One's ratepayer and environmental intervenors that wish to participate).

Pollution Probe (PP) INTERROGATORY #29 List 1

Issue 11 Are the amounts proposed for rate base in 2013 and 2014 appropriate?

Interrogatory

Please provide copies of all of the reports of the Kitchener-Waterloo-Cambridge-Guelph Area Working Group.

Response

The KWCG area regional study is currently in progress. No reports have been completed to date.

Vulnerable Energy Consumers Coalition (VECC)INTERROGATORY #33 List 1

Issue 11 Are the amounts proposed for rate base in 2013 and 2014 appropriate?

Interrogatory

Reference: Exhibit D1, Tab 3, page 4, Table 2

a) Please extend the referenced table to include a comparison of actual transmission capital expenditures, by category, to the Board approved amounts for all previous historic years.

Response

a) Please refer to Interrogatory Response filed at Exhibit I, Tab 12, Schedule 1.02 Staff 55.

Goldcorp INTERROGATORY #1 List 1

Issue 11 Are the amounts proposed for rate base in 2013 and 2014 appropriate?

Interrogatory

Please explain how bypass fees collected by Hydro One affect its revenue requirement. For example, are bypass fees treated as other revenue that is set-off from revenue requirement, or is rate base adjusted by a corresponding amount?

Response

Bypass fees are treated as an adjustment to net book value of the asset, which impacts rate base.

Goldcorp INTERROGATORY #2 List 1

Issue 11 Are the amounts proposed for rate base in 2013 and 2014 appropriate?

Interrogatory

Has Hydro One forecast a Goldcorp bypass fee in the calculation of its revenue requirement for 2013 or 2014? If not, why not? If so, please provide details.

Response

Hydro One does not forecast bypass compensation in the calculation of its revenue requirement. Adjustments are made to net book value when bypass actually occurs.

Goldcorp INTERROGATORY #3 List 1

Issue 11 Are the amounts proposed for rate base in 2013 and 2014 appropriate?

Interrogatory

Ref: May 28, 2012 Evidence, Exhibit D1, Tab 1, Schedule 2, Page 4 of 4, Lines 18 and 19

(a) Please explain why the installation of a third transformer at Red Lake TS was originally included in the 2014 budget.

(b) Please explain why the installation of a third transformer at Red Lake TS was removed from the 2014 budget in Hydro One's August 15, 2012 update to its evidence.

Response

(a) The third transformer at Red Lake TS was not part of the capital expenditures included in the test year rate base in the evidence filed on May 28, 2012. Reference to this project in Exhibit D1, Tab 1, Schedule 2, Page 4, Lines 18 and 19 was included in error and was corrected in the August 15, 2012 update.

(b) Please see response to part (a).

Goldcorp INTERROGATORY #4 List 1

Issue 11 Are the amounts proposed for rate base in 2013 and 2014 appropriate?

Interrogatory

Was an adjustment made to rate base to address the stranded facilities that Hydro One believes will be bypassed by Goldcorp? If so, what was the adjustment to rate base? If not, why not?

Response

Please see response to Exhibit I, Tab 11, Schedule 7.02 Goldcorp 2.

Goldcorp INTERROGATORY #5 List 1

Issue 11 Are the amounts proposed for rate base in 2013 and 2014 appropriate?

Interrogatory

In EB-2005-0501, Hydro One proposed $7.5M in development capital to replace the end of life transformers at the Red Lake TS. Hydro One stated the cost to advance the refurbishment of the Red Lake TS from 2010 to 2007 would be recovered through incremental transformation revenues, and therefore no capital contribution would be required.

(a) What were the actual costs for this project?

(b) What was the subsequent Net Book Value of the Red Lake TS upon completion of the project?

(c) Are any of the original three transformers at the Red Lake TS still in service?

(d) What is the outstanding amount of these advancement costs to be recovered through transformation revenues?

Response

(a) The actual cost of the installation of the new transformers (including removal of the original end-of-life transformers) was $6.7M.

(b) Upon completion of the installation of the new transformers, the Net Book Value of the total Red Lake TS was $14.1 M (which includes all station equipment such as: transformers, breakers, switches, capacitors, etc.). It is noted that the Net Book Value can change over time as other capital modifications occur at the station.

(c) None of the original three transformers at Red Lake TS are still in service.

(d) No transformation connection rate revenues have been attributed to the advancement costs. This is because there has been no new load at Red Lake TS to date that exceeds the total normal supply capacity of the replaced transformers. The advancement cost attributable to the new transformers, at in-service, was $1.1M.

Goldcorp INTERROGATORY #6 List 1

Issue 11 Are the amounts proposed for rate base in 2013 and 2014 appropriate?

Interrogatory

Has ownership in the GL-01 connection facilities (the line being transferred to Hydro One by Goldcorp that was the subject of LTC EB-2011-0106) been included in Hydro One's rate base? If not, why not? If so, at what amount?

Response

The Goldcorp 115 kV line has not been completed by Goldcorp. For this reason the Goldcorp line was not included in the rate base.

School Energy Coalition (SEC) INTERROGATORY #24 List 1

Issue 11 Are the amounts proposed for rate base in 2013 and 2014 appropriate?

Interrogatory

For all major projects planned for 2012, 2013 and 2014 please provide the most updated expected in-service dates (the expected month that the project will be in-service).

Response

The table below provides the expected in-service month and year for all of the major projects in response to Exhibit I, Tab 11, Schedule 9.01 SEC 24.

SUSTAINMENT					
ISD#	**Investment Summary Description**	**Net Total Cost ($M)**	**I/S (Year)**	**I/S (Month)**	
S6	Hanmer TS – 500kV ABCB	26.1	2013	September	
S7	Orangeville TS – 230kV ABCB	28.1	2014	March	
S8	Pickering A SS – 230kV ABCB	5.8	2014	December	
S11	Bruce A TS- 230kV ABCB	35.0	2014	December	
S12	Burlington TS – 230kV ABCB	8.1	2014	August	
S13	Abitibi Canyon SS / Pinard TS: Reconfigure and Demerge	46.0	2013	August	
S15	Wallaceburg: TS – Reconfigure to Address Failed Transformers	26.4	2013	October	
S17	Merivale GIS Bus Replacement	11.0	2013	December	
S19	Integrated DESN Investments	152.1	2014+	Various	
S63	Claireville T14 Replacement	25.0	2013	October	
S30	BSPS Replacement of End-of-Life Equipment	34.6	2014	December	
S39	ITMC Refreshment	4.4	2014	October	
S40	TDCN Cyber Security	10.4	2013	November	
S50	S2B Steel Structure Replacements	7.2	2013	August	
S53	D1A Line Refurbishment	3.2	2013	December	
S54	H27H Line Refurbishment	14.5	2014	October	
S55	V73R/V74R Self Damping Conductor Replacement	9.0	2014	November	
S56	H24C Line Refurbishment	25.7	2014	October	
S57	C27P Line Refurbishment	6.2	2013	December	
S62	H2JK/K6J Underground Cable Replacement (Riverside Jct. x Strachan TS)	89.7	2014	December	
DEVELOPMENT					
ISD#	**Investment Summary Description**	**Net Total Cost ($M)**	**I/S (Year)**	**I/S (Month)**	
D01	New 500 kV Bruce to Milton Double Circuit Transmission Line	709.0	2012	May	
D34	Northwest Reactors for Area Voltage Control	11.2	2014	November	
D02	Installation of Shunt Capacitor Banks at Cherrywood TS Phase 1	7.3	2014	October	
D06	Reconductor the Lambton TS to Longwood TS 230kV Circuits	40.0	2014	December	
D07	Toronto Area Station Upgrades for Short Circuit Capability: Leaside TS Equipment Uprate	26.6	2014	December	
D08	Toronto Area Station Upgrades for Short Circuit Capability: Manby TS Equipment Uprate	17.5	2014	November	
D09	Toronto Area Station Upgrades for Short Circuit Capability: Re-build Hearn SS	103.9	2013	December	
D10	Midtown Transmission Reinforcement Plan	68.6	2014	August	**
D13	Tremaine TS: Build New Transformer Station	18.8	2013	March	**
D14	Barwick TS: Build new Transformer Station	23.8	2013	October	
D15	Nebo TS: Increase Capacity of 230/27.6kV DESN	10.0	2013	October	**
D16	Orleans TS: Build new Transformer Station	13.2	2014	May	**
D17	Bremner TS: Build Line Connection for Toronto Hydro	0.0	2014	December	*
D18	Chalk River CTS: Build 115kV Switching Facilities and connect new Customer Station	0.0	2014	May	*
D19	Nelson TS: Replace T1/T2 DESN with new DESN	15.0	2014	October	**
D20	Samsung South Kent Wind Farm (270 MW)	0.0	2013	June	*
D21	Lower Mattagami Generation Connections	1.7	2013	December	**
D22	Niagara Region Wind Corporation Generation Connection (230 MW)	0.0	2014	June	*
D23	Armow Wind Generation Connection (180 MW)	0.0	2014	June	*
D24	K2 Wind Generator Connection (270 MW)	0.0	2014	November	*
D25	Adelaide/Bornish/Jericho Wind Energy Centres (284 MW)	0.0	2014	October	*
D30	Hawthorne TS: Uprate Short Circuit Capability	11.8	2013	December	
D31	Allanburg TS: Uprate Short Circuit Capability	19.0	2013	December	
D32	Basin TS: Add Reactors	6.0	2013	December	
D33	Main TS: Add Breakers	6.7	2013	December	
D35	Summerhaven SS: Build New In-Line Breaker Station	20.4	2013	July	
D36	Sandusk SS: Build New In-Line Breaker Station	21.9	2013	October	
OPERATIONS					
	The operation projects are planned for in-service in 2015, please see Exhibit D2, Tab 2, Schedule 3, ISD# O1, O4 and O5.				

Please note:
* represents a project that is fully funded by the customer, and hence Net Cost = 0 and does not impact rate base, and
** represents a project that is partially funded by the customer.

Toronto Hydro-Electric System Limited (THESL) INTERROGATORY #2 List 1

Issue 11 Are the amounts proposed for rate base in 2013 and 2014 appropriate?

Interrogatory

Ref: Exhibit D1-3-3/Appendix A/Table 4/Item #D17

a) Please explain why the customer capital contribution for Bremner TS constitutes 100% of the gross total cost. What assumptions underpin this conclusion?

Response

a) Hydro One has calculated the capital cost contributions based on the incremental load forecast provided by THESL. The discounted cash flow (DCF) analysis showed that a 100% capital contribution is required as there was insufficient incremental load growth to offset this cost, and this was conveyed to THESL.

Toronto Hydro-Electric System Limited (THESL) INTERROGATORY #3 List 1

Issue 11 Are the amounts proposed for rate base in 2013 and 2014 appropriate?

Interrogatory

Ref: Exhibit D2/Tab 2/Sch 3/ p74

a) Please explain the impact of the Bremner TS line connection on the current transfer capability between John TS and Esplanade TS. In Hydro One's response, please indicate how 115kV transfer capability will be maintained.

Response

a) The through transfer capability between John TS and Esplanade TS will be reduced by the amount of load on Bremner TS. The only way to maintain existing transfer capability, during such transfer scenarios, is to move the Bremner TS load to other transformer stations in Toronto via the THESL distribution network.

Toronto Hydro-Electric System Limited (THESL) INTERROGATORY #4 List 1

Issue 11 Are the amounts proposed for rate base in 2013 and 2014 appropriate?

Interrogatory

Ref: Exhibit D2/Tab 2/Sch 3/ p74

a) Please provide a detailed cost breakdown of the $60M gross cost for building the Bremner TS line connection.

Response

a) As mentioned in Exhibit D2, Tab 2, Schedule 3, ISD #D17 the project is in a preliminary stage and Hydro One is working with THESL to finalize the scope.

The $60M gross cost for the work is based on the preliminary scope discussed with THESL and budgetary costs for equipment and installation is as follows:

i) Station: Gas Insulated Switchgear (GIS) (230kV rated, operated at 115kV) ~ $30M
ii) Cables: Four 115kV circuits (230kV rated, operated at 115kV) ~ $15M
iii) Protections: ~ $5M
iv) Other costs (interest/overhead/contingencies): ~ $10M

Hydro One will be advising THESL of the detailed project costs when the project scope is finalized, the preliminary engineering and estimating work are complete, and the tender bids for outsourced work have been reviewed.

Toronto Hydro-Electric System Limited (THESL) INTERROGATORY #5 List 1

Issue 11 Are the amounts proposed for rate base in 2013 and 2014 appropriate?

Interrogatory

Ref: Exhibit D2/Tab 2/Sch 3/ p74

a) Has Hydro One considered any alternate designs for the Bremner TS line connection project? If so, please identify any alternative designs that have been considered, and the status of those alternatives.

Response

a) Yes, Hydro One did suggest to THESL potential alternatives for Bremner TS and its line connection. The alternatives were as follows:

- Build station facilities at Esplanade TS and connect to the John to Esplanade 115kV circuits.
- Build station facilities at Bremner TS and install 115kV underground cables between Bremner TS and Esplanade TS.
- Build station facilities at Bremner TS and install 115kV underground cables between Bremner TS and John TS.
- Install low voltage switchgear facilities at Bremner TS and install transformers at another location.

These alternatives were discussed with THESL but THESL indicated that the current Bremner proposal better meets their timeline needs.

Association of Major Power Consumers in Ontario (AMPCO) INTERROGATORY #8 List 1

Issue 11 Are the amounts proposed for rate base in 2013 and 2014 appropriate?

Interrogatory

Ref: D1-1-2/p3, line 1

a) This explanation is a little unclear. Please identify which projects are being referred to in the $27M under-expenditure.

Response

a) The below response corresponds to the updated Pre-filed Evidence which shows the variance for Operations in-service additions to be $34 million below OEB approved levels.

Table 1
In-Service Additions – Operations

Investment Summary Description	2012 ISA Projected ($ million)	2012 ISA Board Approved ($ million)	Variance ($ million)
Network Operations Buildings	0.0	8.9	(8.9)
NMS Upgrade & Enhancements	0.6	3.9	(3.3)
Tx Operating Facilities Sustainment	7.0	3.4	3.6
Hubsite Management Program	3.3	4.1	(0.8)
Telemetry Expansion	1.6	3.4	(1.8)
Wide Area Network	0.0	24.2	(24.2)
Frame Relay Replacement Project	0.0	0.0	0.0
Fault Locating Program	1.0	0.0	1.0
Station LAN Infrastructure	2.7	0.0	2.7
Other Projects / Program < $3M	2.6	4.9	(2.3)
	18.8	**52.7**	**(34.0)**

Association of Major Power Consumers in Ontario (AMPCO) INTERROGATORY #9 List 1

Issue 11 Are the amounts proposed for rate base in 2013 and 2014 appropriate?

Interrogatory

Ref: EB-2008-0272 01-3-1
Ref: EB-2010-0002 01-3-1
Ref: EB-2012-0031 01-3-1

Preamble:
For convenience, the following tables are reproduced from Hydro One's applications in this hearing and the previous two transmission rate hearings.

Table 2
2007 Board Approved versus 2007 Actual Capital Expenditures

Capital Category	2007 Board Approved ($ million)	2007 Actuals ($ million)	Variance ($ million)
Sustaining	$288.1	$210.0	$(78.1)
Development	318.8	272.6	(46.2)
Operations	20.1	4.7	(15.4)
Shared Services	84.6	72.1	(12.5)
Total	$711.6	$559.5	$(152.1)

Table 3
2008 Board Approved versus 2008 Projected Capital Expenditures

Capital Category	2008 Board Approved ($ million)	2008 Bridge Year ($ million)	Variance ($ million)
Sustaining	295.6	280.4	(15.2)
Development	415.6	310.9	(104.7)
Operations	20.4	23.1	2.7
Shared Services	42.8	89.8	47.0
Total	774.4	704.2	(70.2)

(Ref: EB-2008-0272 D1-3-1)

Table 2
2009 Board Approved versus 2009 Actual Capital Expenditures

Capital Category	2009 Board Approved ($ million)	2009 Actuals ($ million)	Variance ($ million)
Sustaining	279.9	300.1	20.3
Development	545.9	516.2	(29.7)
Operations	18.2	20.0	1.8
Shared Services	92.4	81.5	(10.9)
Total	**936.5**	**917.8**	**(18.7)**

Table 3
2010 Board Approved versus 2010 Projected Capital Expenditures

Capital Category	2010 Board Approved ($ million)	2010 Bridge Year ($ million)	Variance ($ million)
Sustaining	321.6	308.3	(13.3)
Development	642.3	537.9	(104.4)
Operations	28.9	10.1	(18.8)
Shared Services	64.9	73.6	8.7
Total	**1,057.6**	**930.0**	**(127.6)**

(Ref: EB-2010-0002 D1-3-1)

Table 2
2011 Board Approved versus 2011 Actual Capital Expenditures

Capital Category	2011 Board Approved ($ million)	2011 Actuals ($ million)	Variance ($ million)
Sustaining	412.1	337.1	(75.0)
Development	609.4	415.9	(193.5)
Operations	43.5	8.8	(34.7)
Shared Services	58.4	48.4	(9.9)
Total	**1,123.4**	**810.2**	**(313.2)**

(Ref: EB-2012-0031 D1-3-1)

Table 3
2012 Board Approved versus 2012 Projected Capital Expenditures

Capital Category	2012 Board Approved ($ million)	2012 Bridge Year ($ million)	Variance ($ million)
Sustaining	431.3	426.7	(4.5)
Development	448.8	412.1	(36.7)
Operations	56.4	47.9	(8.4)
Shared Services	44.8	75.0	30.2
Total	**981.3**	**961.7**	**(19.6)**

(Ref: EB-2012-0031 D1-3-1)

Preamble:
Whatever the cause, it appears that Hydro One frequently and significantly under-spends its approved capital budgets.

a) Are there any mechanisms Hydro One would recommend to the Board to mitigate the effect on customers of the rate impacts from underspending of approved capital budgets?

Response

In-service capital additions, not capital expenditures, represent increases to rate base that ultimately result in changes to Revenue Requirement. As noted in Exhibit I, Tab 12, Schedule 10.03 CCC 30, although capital spending in 2011 was $313.2M below the OEB approved level, in-service additions were only $42.6M below approved levels and net income was impacted by only $0.8M.

The absolute amount of in-service additions and capital expenditures in any given year will typically be different. This difference often arises from the multi-year nature of many transmission capital projects and from the fact that some projects can come into service in stages.

Many other risk factors, often beyond Hydro One's control, affect the total amount of capital spend especially on large transmission projects. Capital Expenditures can vary from year to year for many reasons as pointed out in detail in Exhibit D1, Tab 3, Schedule 1, Pages 4-7. In summary, these items include:

- land and easement acquisition issues
- outage scheduling with other agencies
- projects coming in under-budget
- delays in generation and Green Energy projects.

Ontario Energy Board (Board Staff) INTERROGATORY #54 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/Sch1/p 2/Table 1
In this table, the Sustaining component shows a 45% increase in 2013 compared to 2012. Given that the 2012 component was already 30% above the 2011 actual, this represents an 88% increase from 2011 to 2013. Similarly in the Operations component, the proposed 2014 level is 19% higher than the proposed 2013 level, in spite of the fact that 2012 saw a 4-fold increase in this component relative to 2011.

a) While a brief summary is provided of the factors contributing to these increases, please provide additional specific summary detail on the main factors contributing to these significant increases in the proposed capital expenditures.

b) What process does Hydro One have in place for the planning and prioritization of capital expenditures to deal with these fluctuations?

Response

a) Additional summary detail on Sustaining Capital increased test year expenditures over historic years is provided in Exhibit D1, Tab 3, Schedule 2 on pages 2-4. Further details are provided for Stations on pages 5-55, and for Lines on pages 55-74. The primary investment areas within Sustaining Capital contributing to the increased 2013 expenditures over the 2012 bridge year are summarized as follows:

- Station Reinvestments (+$94M); primarily focused on replacing air-blast circuit breakers and executing integrated station rebuilds at load delivery stations
- Protection, Control and Metering (+$19M): continuing effort on key infrastructure such as the Bruce Special Protection Scheme (BSPS), and replacement of protections on interconnected tie lines.
- Transmission Lines Reinvestment (+$27M): increased replacement of conductor and line refurbishment projects based on condition and demographics information.
- Underground Cables Replacement (+$29M); 2013 has much more substantial expenditure than 2012 due to the timing of the H2JK/K6J underground cable replacement project.

Please note that the Operations Capital 2012 bridge year capital expenditure is an increase over the 2011 historic year in the order of three times. Additional summary detail on Operations Capital increased test year expenditures over historic years is provided in Exhibit D1, Tab 3, Schedule 4 on pages 2-4.

In summary, the funding levels for the bridge and test years have increased from historic years due to several projects planned for 2011 being deferred to the bridge and test years, along with an increase in planned spending on the Wide Area Network project and the NMS upgrade. For detailed information on these projects, please see the Operations Capital Exhibit D1, Tab 3, Schedule 4 on pages 2-4.

b) Hydro One's Investment Planning process is outlined in Exhibit A, Tab 15, Schedule 3. Hydro One's Investment Prioritization process is outlined in Exhibit A, Tab 15, Schedule 4.

It should be noted that Hydro One does not characterize the test year increases to Sustaining capital expenditures as fluctuations from historic and bridge years, but as required continued capital investment to address the aging infrastructure.

Ontario Energy Board (Board Staff) INTERROGATORY #55 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/Sch1/p 4 & 6/Table 2 & Table 3 – Board Approved versus Actual Capital Expenditures
Please provide, in table format, the Board Approved Capital Expenditures and Actual Capital Expenditures for the years 2007 to 2010.

Response

Table 1
2007 Board Approved versus 2007 Actual Capital Expenditures
($M)

Capital Category	2007 Board Approved	2007 Actuals	Variance
Sustaining	288.1	210.0	(78.1)
Development	318.8	272.6	(46.2)
Operations	20.1	4.7	(15.4)
Shared Services	84.6	72.2	(12.5)
Total	**711.6**	**559.5**	**(152.1)**

Table 2
2008 Board Approved versus 2008 Actual Capital Expenditures
($M)

Capital Category	2008 Board Approved	2008 Actuals	Variance
Sustaining	295.6	280.4	(15.1)
Development	415.6	310.9	(104.7)
Operations	20.4	23.1	2.7
Shared Services	42.8	89.8	46.9
Total	**774.4**	**704.2**	**(70.2)**

Table 3
2009 Board Approved versus 2009 Actual Capital Expenditures
($M)

Capital Category	2009 Board Approved	2009 Actuals	Variance
Sustaining	279.9	300.1	20.2
Development	545.9	515.9	(30.0)
Operations	18.2	20.0	1.8
Shared Services	92.4	81.8	(10.6)
Total	**936.5**	**917.8**	**(18.7)**

Table 4
2010 Board Approved versus 2010 Actual Capital Expenditures
($M)

Capital Category	2010 Board Approved	2010 Actuals	Variance
Sustaining	321.6	356.3	34.7
Development	642.3	523.1	(119.2)
Operations	28.9	7.6	(21.3)
Shared Services	64.8	49.1	(15.7)
Total	**1,057.6**	**936.1**	**(121.5)**

Ontario Energy Board (Board Staff) INTERROGATORY #56 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/Tab1/Sch2/p 1/Table 1 – In-Service Capital Additions 2011 – 2014 & Board Staff Interrogatory #64 in EB-2010-0002

(a) Please provide a breakdown of all capital programs, for Sustaining, Operations and Shared Services, that are included in the in-service additions table at the above reference. Please provide this information in table format, identifying the capital program, ISD #, in-service year, Gross Cost, capital contributions, and test year capital expenditure that are booked to the test year rate base. In a separate table, please identify all projects that are included in the capital expenditure budget, but will not be added to the test year rate base. Please provide your response in a format similar to that provided in Board staff interrogatory 64 (a) in EB-2010-0002.

(b) With respect to Development Capital projects, please provide in table format and in a format similar to that in Board staff interrogatory 64 (b) in EB-2010-0002, that identifies all the Development Capital programs, related ISD #, in-service year, Category of investment, Gross Cost, Capital contributions and capital that is booked to rate base in 2012 and 2013. Please identify the projects that are included in the Green Energy Plan. In a separate table, please identify all Development Capital (& Green Energy Plan) projects that are included in the capital expenditure budget, but will not be added to the test year rate base.

Response

(a) Please find the requested tables (Table 1, 2, 3) that includes a breakdown of all capital programs, for Sustaining, Operations and Shared Services that are included in the in-service additions table. This table includes information identifying the capital program, in-service year, Gross Cost, capital contributions, and test year capital expenditure that is booked into rate base. Tables 4 identifies all Sustaining, Operations, and Shared Services projects that are included in the capital expenditure budget, but will not be added to test year rate base.

Table 1
Sustainment Projects – Test Year In Service Additions (ISA)

ISD#	Investment Summary Description	Gross Cost ($M)	Cap. Contr.	I/S (Year)	2013 ISA ($M)	2014 ISA ($M)
S1	Oil Circuit Breaker Replacements	17.6	-	2014[P]	7.6	8.7
S2	SF6 Breaker Replacements	22.1	-	2014[P]	9.9	11.1
S3	GTA Metalclad Switchgear Replacements	52.3	18.0	2015	2.9	10.3
S6	Hanmer TS – 500kV ABCB	26.1	-	2013	25.8	-
S7	Orangeville TS – 230kV ABCB	28.1	-	2014	-	10.9
S8	Pickering A SS – 230kV ABCB	11.6	5.8	2014	-	2.3
S11	Bruce A TS- 230kV ABCB	35.0	-	2014	-	35.0
S12	Burlington TS – 230kV ABCB	8.1	-	2014	-	8.1
S13	Abitibi Canyon SS / Pinard TS: Reconfigure and Demerge	47.0	1.0	2013	46.0	-
S15	Wallaceburg: TS – Reconfigure to Address Failed Transformers	26.4	-	2013	26.4	-
S17	Merivale GIS Bus Replacement	11.0	-	2013	11.0	-
S18	NRC TS Rebuild	21.6	-	2015	-	10.8
S19	Integrated DESN Investments	152.1	-	2014+	12.4	85.4
S20	End of Life CGE Transf. Replacements	3.5	-	2013[P]	9.1	-
S21	End of Life Transformer Replacements	149.7	-	2014[P]	54.9	73.5
S22	Operating Spare Transformer Purchases	25.8	-	2014[P]	11.6	12.9
S63	Claireville T14 Replacement	25.0	-	2013	6.4	-
S23	Disconnect Switch Replacements	17.0	-	2014[P]	7.1	8.5
S24	Capacitor Bank Replacements	8.8	-	2014[P]	4.9	4.4
S25	Instrument Transformer Replacements	6.3	-	2014[P]	3.2	3.2
S26	Insulator Replacements	9.8	-	2014[P]	2.7	2.9
S27	Station Service Replacements	23.6	-	2014[P]	10.4	11.7
S28	Station Grounding Replacements	10.4	-	2014[P]	3.8	5.2
S29	Spill Containment Refurbishment & Installation	22.6	-	2014[P]	8.7	11.3
S30	BSPS Replacement of End-of-Life Equipment	34.6	-	2014	-	34.6
S31	ITC – Line Protections Replacements	7.5	-	2015	2.5	2.5
S32	NYPA Tie Lines – Beck Line Protections Replacements	16.3	5.5	2015	8.3	-
S33	2013 – 2014 Station P&C Replacement	45.0	-	2015[P]	20.7	25.9
S34	2013-2014 Protection Replacements	41.4	-	2014[P]	15.9	21.1
S35	2013-2014 RTU Replacement	16.8	-	2014[P]	7.3	8.4
S36	DC Signaling (Remote Trip) Replacements	9.8	-	2014[P]	4.6	5.0
S37	DC Signaling Replacements (Toronto North & East)	4.3	-	2014[P]	8.7	1.5
S38	Protection Tone Channel Replacements	10.0	-	2014[P]	4.5	5.0
S39	ITMC Refreshment	4.4	-	2014	-	4.1
S40	TDCN Cyber Security	10.4	-	2013	10.4	-
S41	NERC CIP V5 Readiness	19.0	-	2015	-	4.0
S43	Cyber Systems Life Cycle Management	6.0	-	2014	-	6.0
S44	Station Fences and Security	19.7	-	2014	7.4	9.9
S45	Wood Pole Replacement Program	56.8	-	2014[P]	32.0	26.5
S46	Steel Structure Coating Program	20.9	-	2014[P]	7.4	10.5
S47	Shieldwire Replacement Program	11.3	-	2014[P]	4.8	5.7
S48	Transmission Lines Emergency Restoration	15.0	-	2014[P]	7.5	7.6
S49	Insulator Replacement Program	10.6	-	2014[P]	4.6	5.0
S50	S2B Steel Structure Replacements	7.2	-	2013	7.2	-
S51	Steel Structure Replacement Program	7.2	-	2014[P]	2.1	3.6
S53	D1A Line Refurbishment	3.2	-	2013	3.2	-
S54	H27H Line Refurbishment	14.5	-	2014	-	14.5
S55	V73R/V74R Self Damping Conductor Replacement	9.0	-	2014	-	9.0
S56	H24C Line Refurbishment	25.7	-	2014	-	25.7
S57	C27P Line Refurbishment	6.2	-	2013	6.2	-
S58	Ottawa - Hwy 417 Interchange (Recoverable)	4.3	4.3		-	-
S59	Keith TS Hwy 401 Expansion (Recoverable)	29.7	29.7		-	-
S60	Toronto-TTC Maintenance Facility (Recoverable)	20.7	20.7		-	-
S61	Sudbury-Maley Dr Extension/Widening (Recoverable)	3.7	3.7		-	-
S62	H2JK/K6J Underground Cable Replacement (Riverside Jct. x Strachan TS)	89.7	-	2014	-	89.7
	Other Projects/ Programs < $3M	137.0	-		67.3	64.3
					497.3	**706.2**

[P] – Indicates ongoing program work

Table 2
Operations Projects – Test Year In Service Additions (ISA)

ISD#	Investment Summary Description	Gross Cost ($M)	Cap. Contr.	I/S (Year)	2013 ISA ($M)	2014 ISA ($M)
O1	NMS Upgrade	28.0	-	2015	1.0	14.2
O2	Hub Site Management Program	6.5	-	2014	-	6.5
O3	Telemetry Expansion Program	4.6	-	2014	-	4.6
O4	Wide Area Network Project	55.5	-	2015	16.6	3.6
O5	Frame Relay Replacement Project	10.4	-	2015	5.1	-
O6	Fault Locating Program	6.0	-	2014	2.0	4.0
O7	Station LAN Infrastructure Program	8.0	-	2014	4.0	4.0
	Other Projects/ Programs < $3M	39.4	-	2012-2015	16.5	11.1
					45.1	**48.0**

Table 3
Shared Services Projects – Test Year In Service Additions (ISA)

ISD#	Investment Summary Description	Gross Cost ($M)	Cap. Contr.	I/S (Year)	2013 ISA ($M)	2014 ISA ($M)
IT1	Cornerstone Phase 3*	50.5		2011-2014	10.6	12.4
IT2	GIS Implementation	11.9	-	2012-2014	4.0	1.5
IT3	MFA PC and Printer Hardware	4.0	-	Annual	1.9	2.1
IT4	Software Refresh & Maintenance - Enterprise Application Software	9.2	-	Annual	3.9	5.2
IT5	MFA Servers and Storage	6.0	-	Annual	2.3	3.7
	Other IT	9.9	-	Annual	1.8	2.7
C1	Real Estate Facilities Capital	29.3	-	Annual	14.7	14.5
C2	Real Estate Head Office and GTA Facilities Capital	6.9	-	Annual	3.4	3.4
C3	Shared Services Capital – Service Equipment	11.0	-	Annual	5.4	5.6
C4	Shared Services Capital – Transport & Work Equipment	22.9	-	Annual	11.3	11.6
	Other	0.7	-	Annual	0.3	0.3
					59.8	**63.1**

Figures in table represent only the Transmission allocated amounts.

Table 4
Projects Not Added to the Test Year Rate Base

ISD#	Investment Summary Description	I/S (Year)
S4	Albion TS Metalclad Replacement	2015
S5	Kenilworth TS Metalclad Replacement	2015
S9	Richview TS – 230kV ABCB	2017
S10	Beck #2 TS – 230 kV ABCB	2016
S14	Beck #1 SS - Build New Switchyard	2017
S16	Gage TS EOL Asset Replacement Project	2016
S42	Cyber Security of Load Stations	2015
S52	C25H Line Refurbishment	2017

(b) Please find the requested Table 5 that includes a breakdown of all Development capital programs, that are included in the in-service additions table. The projects that are related to the Green Energy Plan have been identified in the table. Tables 6 identifies all Development projects that are included in the capital expenditure budget, but will not be added to test year rate base.

Table 5
Development Projects – Test Year In Service Additions (ISA)

ISD#	Investment Summary Description	Capital Category	Green	Gross Cost ($M)	Cap. Contr.	I/S (Year)	2013 ISA ($M)	2014 ISA ($M)
D01	New 500 kV Bruce to Milton Double Circuit Transmission Line	Category 1		709.0	-	2012	9.3	7.3
D34	Northwest Reactors for Area Voltage Control	Category 2		11.2	-	2014	-	11.2
D02	Installation of Shunt Capacitor Banks at Cherrywood TS Phase 1	Category 2		7.3	-	2014	-	7.3
D06	Reconductor the Lambton TS to Longwood TS 230kV Circuits	Category 4	Green	40.0	-	2014	-	40.0
D07	Toronto Area Station Upgrades for Short Circuit Capability: Leaside TS Equipment Uprate	Category 1	Green	26.6	-	2014	18.8	5.1
D08	Toronto Area Station Upgrades for Short Circuit Capability: Manby TS Equipment Uprate	Category 1	Green	17.5	-	2014	8.3	5.0
D09	Toronto Area Station Upgrades for Short Circuit Capability: Re-build Hearn SS	Category 1	Green	103.9	-	2013	99.9	4.0
D10	Midtown Transmission Reinforcement Plan	Category 1		114.8	46.2	2014	-	68.6
D13	Tremaine TS: Build New Transformer Station	Category 1		30.5	11.7	2013	18.8	-
D14	Barwick TS: Build new Transformer Station	Category 1		23.8	-	2013	23.4	-
D15	Nebo TS: Increase Capacity of 230/27.6kV DESN	Category 2		19.2	9.2	2013	10.0	-
D16	Orleans TS: Build new Transformer Station	Category 2		33.4	20.2	2014	-	13.2
D17	Bremner TS: Build Line Connection for Toronto Hydro	Category 2		60.0	60.0	2014	-	-
D18	Chalk River CTS: Build 115kV Switching Facilities and connect new Customer Station	Category 2		10.0	10.0	2014	-	-
D19	Nelson TS: Replace T1/T2 DESN with new DESN	Category 2		29.8	14.8	2014	-	15.0
D20	Samsung South Kent Wind Farm (270 MW) *(Formerly Chatham Wind Generation Connection)*	Category 2	Green	10.7	10.7	2013	-	-
D21	Lower Mattagami Generation Connections	Category 2	Green	30.9	29.3	2013	1.7	-
D22	Niagara Region Wind Corporation Generation Connection (230MW)	Category 2	Green	51.0	51.0	2014	-	-
D23	Armow Wind Generation Connection (180 MW)	Category 2	Green	2.0	2.0	2014	-	-
D24	K2 Wind Generator Connection (270 MW)	Category 2	Green	55.0	55.0	2014	-	-
D25	Adelaide/Bornish/Jericho Wind Energy Centres (284 MW)	Category 2	Green	55.0	55.0	2014	-	-
D26	Transfer Trip Signaling Enhancement		Green			Annual	-	-
D27	Transmission Station P&C Upgrades for DG		Green			Annual	-	-
D28	Transmission Work to Mitigate Distance Limitation		Green			Annual	2.8	3.0
D29	UFLS and Load Rejection Modification		Green			Annual	-	5.0
D30	Hawthorne TS: Uprate Short Circuit Capability	Category 2	Green	11.8	-	2013	10.9	1.0
D31	Allanburg TS: Uprate Short Circuit Capability	Category 2	Green	19.0	-	2013	17.0	2.0
D32	Basin TS: Add Reactors	Category 2		6.0	-	2013	6.0	-
D33	Main TS: Add Breakers	Category 2		6.7	-	2013	6.7	-
D35	Summerhaven SS: Build New In-Line Breaker Station	Category 1	Green	22.5	2.1	2013	20.4	-
D36	Sandusk SS: Build New In-Line Breaker Station	Category 1	Green	23.8	1.9	2013	21.9	-
	Other Capital Projects (<$3M) with 2013-14 Cashflows						25.9	18.0
							301.8	**205.8**

Table 6
Projects Not Added to the Test Year Rate Base

ISD#	Investment Summary Description	I/S (Year)
D03	Installation of Shunt Capacitor Banks at Cherrywood TS Phase 2	2015
D04	Clarington TS: Build new 500/230kV Station	2015
D05	Installation of Static Var Compensator at Milton SS	2015
D11	Preston TS Transformation	2016
D12	Guelph Area Transmission Reinforcement	2016

Ontario Energy Board (Board Staff) INTERROGATORY #57 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 – Air Blast Circuit Breakers (ABCB) Replacement Projects

a) What is the total population of ABCBs in Hydro One's system? How many of these ABCB's are in "Poor" or "Very Poor" condition as described in the 10 Year Asset Management Outlook?

b) Please provide the number of ABCB units replaced in each of the years for the period 2007 to 2012.

c) How many ABCB units are planned to be replaced in 2013 and 2014 respectively?

d) What is Hydro One's planned schedule of replacement of ABCBs beyond 2014?

Response

a) The total population of ABCBs in Hydro One's system is 190 (reference Exhibit C1, Tab 2, Schedule 2, page 11), with 61 in "Poor" condition and 5 in "Very Poor" condition

b) The below table show historical accomplishments for ABCBs:

Year	Sustainment - ABCB replacements
2007	6
2008	13
2009	7
2010	5
2011	2
2012	4

The above table shows the ABCB replacements that have been done under sustainment projects only. Additional breakers have been replaced or removed from the system under development projects.

c) The number of Air Blast Circuit Breakers planned for replacement in the test years 2013 and 2014 is as follows:

2013	2014
28	22

d) Hydro One is focused on replacement of ABCBs because of their degrading reliability, high maintenance costs, the declining availability of parts, and the fact that ABCBs are typically installed at some of the most critical bulk electrical system stations.

Beyond 2014, the replacements on air blast circuit breakers are to follow a trend of approximately 20-25 units per year.

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 #62 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 9

a) What is the total population of OCBs in Hydro One's system? How many of these OCB's are in "Poor" or "Very Poor" condition as described in the 10 Year Asset Management Outlook?

b) 29 OCB's are planned for replacement in 2013 and 2014. Please provide the number of OCB units replaced in each of the years for the period 2007 to 2012.

c) At the above reference Hydro One states that the annual replacement rate of 0.8% is expected to increase in the future. What is Hydro One's planned schedule of replacement of OCBs beyond 2014?

Response

a) As per Exhibit C1, Tab 2, Schedule 2, page 11, there are 1,923 oil circuit breakers (OCBs) in the Hydro One transmission system. There are 11 OCBs that are classified as “Very Poor” condition and 314 that are classified as “Poor” condition.

b) The following table lists the historical accomplishments for OCB replacements:

Year	# of OCBs replaced
2007	4
2008	13
2009	12
2010	26
2011	19
2012	9

c) The number of OCB replacements is expected to remain generally consistent with test year accomplishments in the near term beyond 2014. Although a significant portion of the large OCB population is approaching its expected service life, near term expenditures will be focused on the replacement of the worst performing units and/or models which are technically obsolete. By roughly 10 years time, it is expected that the number of OCB replacements will need to increase by a factor of 3-4 times test year accomplishment levels to manage risks associated with the compounding demographic pressures of this population.

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.

Ontario Energy Board (Board Staff) INTERROGATORY #64 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 13 – ISD# 3 Metalclad Switchgear Replacement Projects

a) Please confirm if the project at the above reference is the same project as that described in ISD # S3 - *2011/2012 Metalclad Circuit Breakers Replacement – GT* for which Hydro One received Board approval in EB-2010-0002.

b) The project in EB-2010-0002 was to be in-service in "Late 2012". Please clarify if the project is on schedule to be in-service in 2012. If there is a possibility that the project may be delayed, please provide the new in-service date.

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

d) In EB-2010-0002, the total project (gross) costs were stated to be $23.5 million. In this application the costs (for what appears to be the same project) are stated to be $52.3 million. Please explain the reasons for the significant increase in project cost.

Response

a) ISD# S3 in this proceeding is a continuation of the work identified in the EB-2010-0002 proceeding, although at different stations in the Toronto area. This project work will be on-going in nature for approximately the next 10 years across multiple stations.

b) Work has been substantially completed at 2 of the 4 sites identified in EB-2010-0002. The two remaining sites are forecasted to be completed by the end of 2012. Of the locations with planned expenditures in the 2013/2014 test years, the final location will be placed in-service in 2015.

c) The planned project costs through year end 2012 are $19.2 million, and include engineering/design, procurement, and some construction and commissioning activity.

d) The $23.5 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 remaining planned capital expenditure on the project beyond 2012 is $33.1 million to complete remaining design, procurement, construction and commissioning work in achieving the scope defined in ISD #S3 of the current application.

Ontario Energy Board (Board Staff) INTERROGATORY #65 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 – Albion TS Metalclad Switchgear Replacement and ISD# S4. In the current application, Hydro One is proposing to replace Metalclad switchgears at Albion TS. This project is identified as a separate project in the current application and has its own ISD number, that being ISD # S4. There is no comparable project in EB-2010-0002 (Ex D2/T2/S2). However, in the current application, Hydro One states that the "Metalclad replacement work at Albion TS has been delayed…."

a) Please clarify if the replacement of metalclad switchgears at Albion TS, was part of the project (ISD # S3) that received Board approval in EB-2010-0002. If it was not part of project ISD # S3 that received Board approval in EB-2010-0002, please identify the proceeding in which this project was approved by the Board.

b) Hydro One states that the Albion TS replacements have been delayed. What was the original in-service date for this project?

Response

a) The replacement of metalclad switchgear at Albion TS in Ottawa area was not part of the ISD #S3 in EB-2010-0002, which was for replacement of switchgear in the Toronto area.

   The Albion TS project (ISD #S4 project in this proceeding) has never been presented to, nor approved by the Board.

b) The original in-service date for the project was 2014. Per the August 15 update, the in-service date has been delayed until 2015.

Ontario Energy Board (Board Staff) INTERROGATORY #66 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 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.

Response

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.

Ontario Energy Board (Board Staff) INTERROGATORY #67 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 – Merivale GIS Replacements
At the above reference Hydro One confirms that the Merivale GIS project has been delayed by 6 months and that in-service date had shifted to 2013.

a) In EB-2010-0002, the Board approved the above referenced project. Hydro One proposed to spend $6 million in 2011 and 2012 respectively. Please provide a description of the work that was undertaken in 2011 and 2012 and provide a high level cost breakdown for this work.

b) In the current application, Hydro One is proposing to spend additional capital of $4.9 million. Please provide the reasons for this additional spending. Please provide a description of the work that will be undertaken in 2013 and 2014.

Response

a) The planned project costs through year end 2012 are $6.1 million, and include engineering/design, equipment procurement, and some construction activity.

b) The total project costs are not increasing, there has only been a shift in expenditure year. The remaining planned capital expenditure on the project in 2013 is $4.9 million to complete remaining construction and commissioning work in achieving the scope defined in ISD #S17 of the current application.

Ontario Energy Board (Board Staff) INTERROGATORY #68 List 1

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

Interrogatory

Ref: Exhibit D1/Tab3/Sch2/p 21 - Power Transformers; 10 Year Asset Management Outlook 2012-2021, p 36

a) In its last rate application (EB-2010-0002), at Ex D1/Tab 3/S2/p. 18, Hydro One stated "In total, Hydro One has 1467 transmission transformers in service". In the 10 Year Asset Management Outlook and in the current application, Hydro One states, "In total, Hydro One has 719 1arge transmission class transformers in service". Please explain the large difference in the total number of transformers noted in the two filings.

b) 25 power transformers are planned to be replaced in 2013 and 2014. Please provide a breakdown by class of transformers (Step-down, Auto-transformer, Phase Shifters or Regulators) that will be replaced in the test years.

c) Please provide the number of transformers, by class, which were replaced in each of the years for the period 2007 to 2012.

d) Please provide the total number of transformers in-service in each of the years from 2007 to 2014 (estimate).

Response

a) The 10 Year Transmission Asset Management Outlook and the current application identify only the 719 large transformers with primary winding voltage of 115 kV and above. In the Hydro One document in EB-2010-0002, Exhibit D1, Tab 3, Schedule 2, page 18, a total count of 1,467 transformers is noted. This total includes additional types of transformers including, grounding transformers; regulators; shunt reactors; and station service transformers with primary winding voltage of less than 115 kV (44kV, 27.6kV, and 13.8kV).

b) The breakdown by class for the 25 power transformers planned for replacement under ISD # S21 in 2013 and 2014 is listed below.

Year	Step-down Transformer	Auto-Transformer	Total
2013	9	1	10
2014	10	5	15

c) Power transformers replaced under Sustaining Capital in each of the years for the period 2007 to 2012 are provided in the following table, including both replacements under the Power Transformer category and Station Re-Investment category.

Year	Step-down Transformer	Auto-Transformer	Reactor	Regulator	Phase Shifter	Total
2007	3	1	1		0	5 (*)
2008	3	1	1	1	0	6 (*)
2009	2	2			0	4
2010	10				0	10
2011	14	2			0	16
2012	14	3	2	1	0	21

* Note: The above table reflects updated numbers; after typographical errors were observed in the table presented on Exhibit C1, Tab2, Schedule 2 page 25. Expenditures are unchanged.

d) The total number of power transformers in-service in each of the years from 2007 to 2014 are as follows:

Year	2007	2008	2009	2010	2011	2012	2013	2014
Total of Power Transformers with 115 kV and above	716	717	718	718	719	724*	727 *	729 *

*projected estimate

Ontario Energy Board (Board Staff) INTERROGATORY #69 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 38 – ISD# S30 – Bruce Special Protection System (BSPS) Replacement

a) It appears the project will be delayed from 2012 to 2014. Please provide a description of the work that was undertaken in 2011/2012 and a high level breakdown of the costs incurred in 2011 and 2012.

b) Please provide a description of the work that will performed in 2013/2014 and a high level cost breakdown for this work.

Response

a) The in-service date of the project has been moved to 2014, primarily due to longer than anticipated stakeholdering of the complex project scope with external parties.

   Work completed in 2011 and 2012 includes engineering/design, procurement of material, some field installation, and testing of communication system required for BSPS functionality. Planned project expenditures through year end 2012 are $5.9 million.

b) Work planned for 2013 and 2014 includes further engineering, installation of equipment, and commissioning/testing to complete the scope defined in ISD #S30 of the current application. Total expenditures planned for 2013 and 2014 are $28.7 million.

Ontario Energy Board (Board Staff) INTERROGATORY #70 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 38 and ISD# S31 – Interprovincial Transmission Company – Line Protection Replacements; ISD# 22 in EB-2010-0002

Hydro One states that the above project "has been previously included in EB-2010-0002 proceeding as project S22...."

a) Please clarify, if the above referenced project is the same project that received Board approval in EB-2010-0002.

b) Please clarify if the project approved in EB-2010-0002 is on schedule to be in-service by "Late 2012" as originally proposed. If the there is a possibility that the project may be delayed, please provide the new in-service date.

c) Please provide a description of the work that was undertaken in 2011/2012 and a description of the work that will be undertaken in 2013/2014. Please provide a high level cost breakdown for the work performed in 2011/2012 and a cost breakdown for work that is planned in 2013/2014.

Response

a) Yes, they are the same project.

b) The Line Protection replacement for one of the four lines (B3N) was completed in 2010. However, due to limitations in ITC's availability of resources and funding, the protection upgrades on three remaining lines L4D, L51D and J5D will not be completed until 2015.

c) The planned expenditures in 2011/2012 are $50 thousand for preliminary engineering of the three remaining tie-line protection replacements. Work to be undertaken in 2013/2014 covers further engineering, construction and commissioning activities for two of the remaining three tie-line protection replacements, with planned test year expenditure of $5.0 million. An additional $2.5 million expenditures is planned for 2015 for the construction and commissioning of the final tie-line protection replacement. This will achieve the scope defined in ISD#31 of the current application.

Ontario Energy Board (Board Staff) INTERROGATORY #71 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/Sch4 – Operations Capital
In EB-2010-0002 Hydro One received Board approval to undertake a building expansion of the OGCC. The cost of the project over two years was $23.1 million. In that application Hydro One stated "**As an alternative to expanding the OGCC building, consideration was given to moving staff to nearby "overflow" locations or decentralizing some departments.** Analysis of these options revalidated the one centre strategy that lead to the creation of the OGCC. In addition to being more costly due to lease costs and lost time due to travel, the effectiveness of operations would be diminished. The operations functions at the OGCC manage real time or near real time plans, actions and events and need to interact tightly, promptly and efficiently to do so. This can only be achieved if all staff are in one building. The best option is to enhance and expand the OGCC building facilities". [Emphasis Added]
However, in the current application, Hydro One appears to have deferred the OGCC expansion project and appears to have exercised options that were previously deemed to be not cost effective.

a) Please clarify when Hydro One undertake the work proposed in ISD # O1 (in EB-2010-0002 or confirm if the project been cancelled.

b) Please explain the rationale for not undertaking the project and the reasons for implementing solutions that were previously deemed to be "more costly".

c) Please clarify if the cost of the expansion that was approved in EB-2010-0002 but not performed is included in the company's 2011/2012 Board Approved Transmission Rate base.

Response

a) The investment in Network Operating Building Expansion was made up of two components. The Ontario Grid Control Centre (OGCC) expansion project (primary facility) was the first component and accounted for $2M of the planned investment over the test years 2011 and 2012 and is currently an in-flight project. The remainder of the investment was to account for the Backup Control Centre expansion project which has been deferred.

b) The Ontario Grid Control Centre (OGCC) was at capacity both in terms of physical space and infrastructure heating and cooling (HVAC) capacity. Investments have been and continue to be made in the OGCC (2012) to upgrade the OGCC HVAC infrastructure. These upgrades along with the leased office space have alleviated all immediate space and infrastructure concerns. This action was necessary to ensure the continued reliable operation of the OGCC facility. In the short term, leased facilities for operations staff, as well as, other Hydro One staff working out of the Barrie area have been procured. For the long term, a study is under way which considers staffing and space requirements for all affected Hydro One Lines of Business in the Barrie area.

The Backup Control Centre project has been deferred pending a review of the Backup Control Centre strategy in consideration of the current and future back-up needs of all Hydro One's real time operations functions. The review process also continues to investigate available technologies and commercial data services to look for the greatest possible efficiencies.

Please see Exhibit D1, Tab 3, Schedule 4, pg. 12-13 for further details.

c) This investment was included in Hydro One's 2011/2012 Board Approved Rate Base.

Ontario Energy Board (Board Staff) INTERROGATORY #72 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 D2/Tab2/Sch3 - ISD# D1 Bruce to Milton project
With respect to the costs of the Bruce to Milton Project, Hydro One received Board approval to add to rate base the cost of the project in 2012 on the basis that it would be in-service by December 31, 2012. The total cost was stated to be $752 million. In the current application, Hydro One states that the costs are lower at $709 million.

Please clarify if the 2013 transmission rate base has been adjusted to reflect the updated costs of the project.

Response

The 2013 transmission rate base has been adjusted to reflect the updated costs of the Bruce to Milton Project.

Details pertaining to the capital that is booked to rate base can be found in Exhibit I, Tab 12, Schedule 1.03 Staff 56, part (b).

Energy Probe (EP) INTERROGATORY #52 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, Tab 3, Schedule 2, Page 4 &
Exhibit D1, Tab 3, Schedule 1, Page 4, Tables 2-3 &
Exhibit A, Tab 14, Schedule 4, page 3

a) Given Sustainment Budget under-spending in 2011 please provide the latest 2012 YTD estimate.

b) Based on Hydro One Networks' investment prioritization process, what areas of 2013-2014 Sustainment CAPEX would be reduced if HO Sustainment Budget was reduced by 10%?

c) Please explain, with reference to risks and impacts, why these areas were selected.

d) What areas of Sustainment CAPEX would be increased if the 2013-2014 Sustainment Budget was increased by 10%?

e) Please explain, with reference to risks and impacts, why these areas were selected.

Response

a) The August 15th update of Exhibit D1, Schedule 3, Tab 2, Table 1 provides the latest 2012 forecast for Sustaining Capital.

b) & c)

SUSTAINING CAPITAL REDUCTIONS

The deferrals identified below are based on a review of the risks to Hydro One's business values, as opposed to working through the full prioritization process. Time constraints prevented a full review of the plan as would occur through the Investment Planning and Prioritization processes.

Sustaining Capital reductions in the order of 10% over the test years are outlined below, along with the impacts to risk and key business values. Deferral of the Capital requirements would put compounding pressures on future spending requirements in both Capital and OM&A. Although not resubmitted in this application, information presented in EB-2010-0002 Exhibit C1, Tab 2, Schedule 2, Table 4A and 4B is still applicable for the linkages in reductions in Sustaining Capital and the impact on other Capital and OM&A investment areas.

<u>Station Re-investment ($80 million over 2013 and 2014 combined)</u>

This reduction would result in deferral of 4 to 5 Integrated DESN Investment projects beyond the test years (ISD#s S18 and S19). These projects are intended to replace multiple end of life (EOL) assets at a station in an integrated and efficient manner as a single work package. Deferral of projects would result in delays addressing customer reliability, environment and worker safety risks associated with the multiple EOL assets. Implementation of work in this integrated and efficient manner would be lost. While some components will be addressed through reprioritization of individual component replacement programs, given these DESN stations directly supply load customers and where multiple elements at the station are known to be in poor condition, there would be an increased risk of equipment failure resulting in customer interruptions if the work is deferred.

<u>Transmission Line Re-Investment ($40 million over 2013 and 2014 combined)</u>

This reduction would result in deferral of 2 to 3 Line Reinvestment projects to beyond the test years (ISD#s S52-S56). These projects are intended to replace multiple end of life (EOL) assets on a transmission line in an integrated and efficient manner as a single work package. Deferral of projects would result in delays addressing system and/or customer reliability, and the potential public and worker safety risks associated with the multiple EOL assets in the public domain. Implementation of work in this integrated and efficient manner would be lost. While some components will be addressed through reprioritization of individual component replacement programs, given multiple elements on the transmission line are known to be in poor condition, there would be an increased risk of equipment failure resulting in customer interruptions if the work is deferred.

<u>Overhead Transmission Lines ($15 million over 2013 and 2014 combined)</u>

This reduction would result in significantly reduced levels of tower coating (ISD #S46), with deferral of work beyond the test years. Deferring tower coating results in higher coating costs in the future due to deterioration that takes place during the deferral period. If towers are not coated in time, steel member replacement may be required at a much higher cost compared to coating. Many of Hydro One’s towers are showing a significant degree of corrosion and deferral of this type of work can only be made for so long until much larger programs are required to deal with wide spread deterioration of tower assets. Failure to adequately manage the risks associated with aging steel towers increases risk to public and staff safety as well as system and customer reliability in the event that towers fail catastrophically.

d) & e)

SUSTAINING CAPITAL INCREASES

A similar approach was used in advancing investments, as was used to defer investments. Risks to Hydro One's business values were assessed and the areas of greatest risk were given priority with further consideration given to resourcing, e.g., available skilled engineering staff and the longer term benefits.

Sustaining Capital increases in the order of 10% over the test years are outlined below, along with the impacts to risk and key business values. Increase of the Capital requirements would somewhat offset increasing pressures of both Capital and OM&A for future years. Although not resubmitted in this application, information presented in EB-2010-0002 Exhibit C1, Tab 2, Schedule 2, Table 4A and 4B is still applicable for the linkages in increases in Sustaining Capital and the impact on other Capital and OM&A investment areas.

In general, additional capital spending would help maintain historical system reliability and allow for further work to manage deteriorating equipment reliability trends in certain areas; and would increase the ability to manage technical obsolescence of certain legacy technologies and better manage the compounding demographic pressures of the aging asset base. Additional impacts to key business values are noted below. With additional Sustaining Capital, Hydro One would make additional investment in these areas:

<u>Station Reinvestment ($60 million over 2013 and 2014 combined)</u>

Advance an additional 2 to 3 air-blast circuit breaker replacement projects into the test years to further address the reliability and cost pressures associated with this poor performing and OM&A intensive equipment which is typically found at critical network stations.

<u>Power Transformers ($25 million over 2013 and 2014 combined)</u>

Increase the number of replacements by approximately 2 to 3 per year to continually improve the management of reliability and environmental risks associated with the aged fleet in degrading condition. Further capital replacements will ease the long-term OM&A expenditures, as new technology typically has lower preventive maintenance costs and lower expenditures associated with corrective maintenance and refurbishment with additional aged transformers being removed from service.

<u>Transmission Lines Reinvestment ($50 million over 2013 and 2014 combined)</u>

Complete an additional 2 to 3 major projects involving replacement of EOL conductor and other associated line hardware. Further increasing the fleet replacement rate would allow a slightly more proactive strategy to better address reliability and safety risks as the condition of the very large inventory degrades faster than the replacement rate.

Energy Probe (EP) INTERROGATORY #53 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, Tab 3, Schedule 3, Page 11, Table 1 &
Exhibit D1, Tab 3, Schedule 1, Page 4, Tables 2-3 &
Exhibit A, Tab 14, Schedule 4, Page 3

a) Given the major Development Budget under-spending in 2011 and 2012, please provide the latest 2012 YTD estimate.

b) Based on Hydro One Networks' investment prioritization process, please identify what areas of 2013-2014 Development CAPEX would be reduced if HOs Development Budget was reduced by 10-20 %?

c) Please explain, with reference to risks and impacts, why these areas were selected

Response

a) The August 15th update of Exhibit D1, Schedule 3, Tab 3, Table 1 provides the latest 2012 forecast for Development Capital.

b) The 2013-2014 Development Capital is comprised of virtually all non-discretionary work. This work is driven either by transmission license requirements; addressing reliability needs identified by the OPA and IESO; complying with codes, standards and regulations; meeting the governments GEGEA policies; and addressing safety and high risk situations. Thus a reduction in the Development Capital by 10-20% (i.e. an amount of $100M-$200M gross CAPEX over the test years) would require Hydro One to make significant reductions to spending on this non-discretionary work. In several cases this would result in Hydro One being in violation of its license obligations, for example: Long Term Energy Plan priority projects and connection of load or generation customers.

c) As outlined in part (b) one of the risks if such reductions were required would be the violation of Hydro One's transmission license obligations. It could also impact Hydro One's ability to satisfy government priority project need dates, and the reliability of the transmission system.

Energy Probe (EP) INTERROGATORY #54 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, Tab 3, Schedule 4, Page 2, Table 1 &
D2, Tab 2, Schedule 2, Page 6, O4 &
Exhibit D2, Tab 2, Schedule 3

a) Please provide an update of the Wide Area Network project, including capital expenditures to date variance from budget, cash flow and in-service dates.

b) Is HO Telecom the Project Manager and/or owner of the facilities and/or service provider? Please explain

Response

a) The expenditures on the WAN project to the end of 2012 are expected to total $12.7M. This represents zero variance from the updated budget as of August 15, 2012. With regard to future cash flow and in-service dates, the detailed plan for the WAN project is currently being reviewed to ensure its rollout and expenditures will align with the deployment, and growth in utilization, of the telecom dependent investments for which it is intended. Present indications are that the growth may be slower than was projected in 2010 when the WAN was being planned. At this time, the first phase of the WAN is expected to be in service by the end of 2013 and the total project by 2015.

b) Due to the fact that the WAN must meet stringent and specialized reliability, performance and cyber security requirements for control of the grid, it is being engineered and project managed by Hydro One Networks. Further, as all of the applications identified for the WAN are for the needs of Hydro One Networks it will be owned by Hydro One Networks. It is expected that Hydro One Telecom will provide operations services for the WAN systems in the future.

Energy Probe (EP) INTERROGATORY #55 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, Tab 4, Schedule 4, Page 1, Tables 1-3

a) Confirm that the major driver for the real estate CAPEX increase in 2013-2014 is the Head Office/GTA facilities improvements deferred from 2011-2012.

b) Did the Board tell HO to defer the Head office and GTA work? If not, who made the decision to defer?

c) Given the major under-spend in the Sustaining and Development budgets in 2011, was this decision re Head office refurbishment reconsidered?

d) Given the overall increase in CAPEX in the test years, why cannot this work be phased over a longer period than currently proposed?

Response

a) The majority of the Capital Expenditure increase for Real Estate in 2013/2014 is related to the head office/GTA facilities improvements which were deferred from 2011 and 2012.

b) In recent Transmission and Distribution Board Decisions, the Board suggested Real Estate was an area where capital expenditures could be deferred.

c) Hydro One commenced renovations to head office space in 2011. The work is expected to continue in bridge year and test years.

d) The planned improvements are necessary now as major head office building infrastructure elements are now at the end of their life and require replacement. (This includes the raised flooring, which presents a health and safety issue with increasing number of tripping hazards.) Similarly, furniture systems acquired from the previous tenant and refurbished are also now considered to be at end of life.

School Energy Coalition (SEC) INTERROGATORY #25 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 A /Tab 15 /Sch 6/ p 18

How does the Applicant select construction/operations/maintenance contractors?

Response

Hydro One selects contractors by using rigorous sourcing processes. Materials and services are selected to assure the best value for money with consideration to health, safety and the environment through a process that is fair, open, transparent and accessible to qualified Suppliers.

Contracting opportunities are posted through the Hydro One website and are open to all potential contractors. Bids are rated against pre-determined weighted evaluation criteria, typically including technical specifications, delivery requirements, supplier and/or material performance, pricing, terms and conditions; and the highest rated compliant bidder is awarded the work.

School Energy Coalition (SEC) INTERROGATORY #26 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

[A-15-1/p.2]
Please reconcile the data on Table 1, with the table on p.1 of A-13-1, Appendix A.

Response

Please see the response to Exhibit I, Tab 2, Schedule 8.01 PWU 1 (b).

School Energy Coalition (SEC) INTERROGATORY #27 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

[A-15-1/p.2]
Please provide a copy of the Global Insight's February 2012 forecast.

Response

The Power Planner 4th Quarter 2011 Report prepared by IHS Global Insight released in February 2012 has been filed at, Exhibit I, Tab 12, Schedule 9.03 SEC 27, Attachment 1, pursuant to the Board's Practice Direction on Confidential Filing. Hydro One's Disclosure Policy, as well as applicable securities legislation, prohibits the release of non-public, financial information on a selective basis to individuals or groups of individuals. Hydro One is prepared to share a copy of the confidential filing with intervenors who have signed the Board's confidential undertaking form.

This report has 77 pages, containing an introduction, an executive summary of US macro-economic conditions, a summary of US pricing environment, 30 detailed tables (Table A1 to Table A30), and a technical appendix describing the variables used. Table A11 (Total Transmission Plant: JUEPT@NOC) and Table A24 (Total Operation and Maintenance: JETOMMS) from this report are the source information for compiling Table 1 in Exhibit A, Tab 15, Schedule 1.

The 30 detailed tables contain forecasts for two major components: 1) the construction cost model and 2) the O&M model. The construction cost model offers ten year forecasts for national material and equipment cost indexes, regional building material and labor cost indexes, and regional electric and gas utility construction cost indexes. The O&M model offers ten year forecasts based on the expense category line items of the Uniform System of Accounts as defined by the Federal Energy Regulatory Commission for major electric utilities and major natural gas pipeline companies.

School Energy Coalition (SEC) INTERROGATORY #28 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

[A-15-4/p.3]
Which of the Measure/Key Performance Indicator does the Applicant quantitatively measure? For each one, please provide the specific measure used.

Response

Currently the specific quantified measures used are shown on the attached table on page 2.

Strategic Objective	Performance Measure
Injury-free Workplace	Medical Attentions (# of medical attentions per 200,000 hours worked)
Satisfying our Customers	Transmission Customer Satisfaction (% satisfied)
	Distribution Customer Satisfaction (% satisfied)
Reliable Transmission and Distribution	Transmission Duration of Customer Unplanned Interruptions on 115/230kV Network System per delivery point (minutes/delivery point)
	Distribution Duration of Customer Interruptions (hours per customer)
Employee Engagement	Employee Survey (Grand Mean)
Shareholder Value	Net Income After Tax ($M)
Achieving Productivity Improvements and Cost-Effectiveness	Transmission Unit Cost (Capital and OM&A per Asset) %
	Distribution Unit Cost (Capital and OM&A costs per km of line) $'000/km

School Energy Coalition (SEC) INTERROGATORY #29 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

[A-15-5/p.2]
With respect to IROVs:

a. How many were prepared, approved, and rejected in each of 2010, 2011 and 2012?
b. How many were prepared, approved, and rejected, for projects that were initially below the Board's materiality threshold, but the IROV would have put it at or above the materiality threshold.

Response

a. The following number of IROV's were prepared and approved:
   - 2010 – 15
   - 2011 – 7
   - 2012 – 15

   No prepared IROV's were rejected

b. None

School Energy Coalition (SEC) INTERROGATORY #30 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

[A-16-1/p.6]
Please provide the full survey.

Response

Please see Attachment 1 for the Large Customer Screener and Attachment 2 for the Transmission Generator Customer Screener.

LARGE CUSTOMER SCREENER

WAVE 1 2011 FINAL

Time Started:_____________	Time Completed:__________	Elapsed Time:_____________
Name:_________________________________	Telephone: (_______)_______________________	
Company Name:______________________________	Title:__________________________________	
Address:____		
City:_______________	Province/State:____________	Postal/Zip Code:_______________
Interviewer:__________________________________	Date:___________________________	

Sample:

A. TRANSMISSION Tx (asset TNAM/T-DNAM)
- Utility (LDC) 1
- Industrial 2

DISTRIBUTION Dx (asset DNAM)
- Utility (LDC) 3
- Retail.................................. 10

Tx/Dx
- Utility (LDC) 5
- Industrial 6

B. Market participant
- Yes.................................. 1
- No 2

NOTE TO ALL: Screeners and W1 and W2 Method are all changed in 2010.

W1 E-mail Review Invitation and Link By Hydro One using IntelliPulse PINs

W1 Telephone Review Reminder By Hydro One Account Exec from List provided by IntelliPulse -

- Provide Review method choice to IntelliPulse

I am calling because IntelliPulse has indicated that you haven't had the opportunity to complete the on-line Satisfaction evaluation yet.

A. You have a few options for how you want to complete this evaluation. I can record how you would like to respond and let IntelliPulse know your preference. They can call you over the telephone, you have the email with the web site link so you can log onto the questionnaire and complete it online, or IntelliPulse can fax, or e-mail the questionnaire to you. Which would you prefer?

CIRCLE ONE:

Telephone .1	Do you have a particular date and time that you would like to book the Review with IntelliPulse, or have IntelliPulse call you to set a time for the Review? RECORD Date: ________________ Time: _____________a.m./p.m.
Web 2	Do you need me to re-send the original email to you? CONFIRM:

	e-mail address: .... If IntelliPulse hasn't received you completed Review by April 23, they will call you to complete it by telephone.
Fax 3	OBTAIN FAX NUMBER ( ) IntelliPulse will fax the questionnaire to you, along with a fax number for you to return your completed opinions. They will send the fax to you in the next couple days. If IntelliPulse hasn't received you completed Review by April 23, they will call you to complete it by telephone.
e-mail 5	OBTAIN e-mail ADDRESS: .... IntelliPulse will e-mail the questionnaire to you in the next couple of days. Once you receive it, would you please print it and then fax your opinions back to IntelliPulse. The fax number will be in the e-mail.
Refuse 6	**IF REFUSES SPRING ASK**: A. May we send the questionnaire to you in the Fall or can IntelliPulse call you in the Fall and have you answer the questions at that time? No ....1 ask B Email web link in Fall.........................2 Telephone call in Fall 3
	B. IF REFUSES FALL ALSO, ASK: Would you allow IntelliPulse to call you to ask you to answer one single question on your overall satisfaction with Hydro One? **Note: IntelliPulse must make this call and obtain the score, the AE is not allowed to collect it.** Do you have a particular date and time that I can tell IntelliPulse to call you? RECORD Date: ________________ Time: ______________a.m./p.m.
Do not call again..........8	IF RESPONDENT ABSOLUTELY REFUSES AND STATES NEVER TO BE CALLED AGAIN, THANKS AND RECORD AND LOG ON PERMANENT REFUSAL LIST

THANK RESPONDENT AND REPEAT WHAT STEPS THEY HAVE CHOSEN AS A CONFIRMATION.

On-line version Introduction:
Hydro One commissioned IntelliPulse Inc., a Canadian research firm to conduct the 2011 customer satisfaction research.

Hydro One believes building a strong relationship with their customers is of prime importance. Collecting feedback from you is key to help understand your needs and get input on your current relationship with Hydro One.

For this review, please keep your organization's TRANSMISSION/DISTRIBUTION) service in mind, not your residential electricity service.

B. Hydro One appreciates the time you spend and the feedback you provide. The review takes about 10 to 15 minutes depending on your answers.

Telephone Review Call to On-line non-completes by IntelliPulse:

Hello, I'm ___________________ calling on behalf of HYDRO ONE. I am from IntelliPulse, a Canadian market research firm. May I please speak with (INSERT NAME)?

(ARRANGE CALLBACK AS NEEDED. IF RESPONDENT NOT AVAILABLE, BUT HAS VOICE MAIL OR OTHER MESSAGE SYSTEM, LEAVE A MESSAGE THAT YOU ARE CALLING ABOUT THE REVIEW THEY WERE ASKED TO PARTICIPATE IN BY HYDRO ONE [THEY SHOULD HAVE RECEIVED A LETTER FROM THEIR ACCOUNT EXECUTIVE], LEAVE YOUR NAME AND MESSAGE THAT YOU WILL CALL BACK. LEAVE NO MORE THAN 2 OR 3)

	DAY	DATE	TIME		DAY	DATE	TIME
CALLBACK #1				#11			
CALLBACK #2				#12			

(WHEN CONNECTED TO PERSON, CONTINUE.)

Your company should have received a letter and a telephone call from Hydro One about my call. Hydro One's goal is to achieve a superior level of customer service and they need feedback from customers like you. We're conducting a customer satisfaction review for them and would like to include your opinions. May I continue? (IF NECESSARY SAY; please let me assure you that we are not selling anything. Your answers are completely confidential and will be used for research purposes only.)

Telephone .1	IF RESPONDENT CANNOT CONTINUE NOW, ASK FOR DATE AND TIME WHEN YOU CAN CALL BACK AND FINISH THE REVIEW. Date: ________________ Time: ______________a.m./p.m.

C. Hydro One appreciates the time you spend and the feedback you provide. The evaluation takes about 10 to 15 minutes depending on your answers.

D. May I please proceed with asking you the questions and getting your answers over the telephone?
Yes …. START AT INTRODUCTION JUST BEFORE SECTION 1.
No….. IF RESPONDENT REFUSES TO ANSWER THE QUESTIONNAIRE, CONTINUE

E. Would it be alright to contact you in the fall to complete the review?
Yes … CONTINUE TO F
No …. RESPONDENT **NOT** TO BE CONTACT, GO TO QG

F. Would you prefer to be contacted by email with a website link or should I telephone you in the fall?
Web link …1
Telephone..2

RECORD W2 CONTACT METHOD. IN W2, RESPONDENT IS CONTACTED **ONLY** IN THEIR SELECTED WAY IN THE FALL.

Thank you. We will call/email you in September to complete the review at that time.

G. Would you be willing to tell me … Q12A AND READ QUESTION and RECORD ANSWER.
1-2a. How satisfied are you with HYDRO ONE overall? Would you say you are… (READ LIST)?

Very satisfied	Somewhat satisfied	Neither satisfied nor dissatisfied	Somewhat dissatisfied	Or, very dissatisfied	Don't know (DO NOT READ)
5	4	3	2	1	x

IF RESPONDENT ANSWERED Q12A ONLY, SKIP TO Q8.1 AND 8.2 AND RECORD ANSWERS.
Respondent is considered a complete and does NOT get put into the W2 sample

OR

IF RESPONDENT REFUSES TO ANSWER Q12A
Respondent is considered a REFUSAL and is NOT contacted in W2.

IF RESPONDENT NOT CONTACTED IN W1 (DID NOT ANSWER THE PHONE),
Respondent is put into the W2 sample and received a HO email in the Fall.

For this questionnaire, please keep your organization's CHECK SAMPLE TYPE TO INSERT (transmission/distribution/transmission and distribution) service in mind, not your residential electricity service.

Section 1: Overall Impressions of HYDRO ONE [1]

Please think about your overall impressions of HYDRO ONE.

1-1. Please rate your overall impression of the company on a one to ten scale, where **1** means your impression is **very unfavourable** and **10** means **very favourable**. You may use a 1, a 10, or any number in between.

Very favourable									Very unfavourable	Don't know (DO NOT READ)
10	9	8	7	6	5	4	3	2	1	11

1-2a. How satisfied are you with HYDRO ONE overall? Would you say you are... (READ LIST)?

Very satisfied	Somewhat satisfied	Neither satisfied nor dissatisfied	Somewhat dissatisfied	Or, very dissatisfied	Don't know (DO NOT READ)
5	4	3	2	1	x

1-1a. What is the main issue that Hydro One could address to meet your business needs? **DO NOT READ – DO NOT SHOW PRECODES ON WEB QUESTIONS OR ON PAPER QUESTIONNAIRE**

Communications/proactive phone calls
Reliability
Accessibility
Directory of contacts
Cost
Other specify ____________________

IF LDC, SKIP TO Q1-4.
ASK Q1-3 OF ALL INDUSTRIAL/RETAIL.

1-3. Based on your expectations of service from a utility, whether it is the gas company, phone company or electricity company, in general do you think Hydro One's performance as a utility is....?

Much better than expected	Somewhat better	Just as expected	Somewhat worse	Or, much worse than expected of a utility	Don't know (DO NOT READ)
5	4	3	2	1	x

[1] 'Detailed" next to question number indicates question asked **only** in the long version of the questionnaire. No 'detailed' indicates the question is asked in the **both** long and short questionnaire versions.

1-4. Considering the overall quality of the transmission/distribution service you get from HYDRO ONE, how would you rate the value for the money provided by HYDRO ONE. Please use a scale of 1 to 10, where a **1** means **poor value** and a **10** means **excellent value.** You may use a 1, a 10 or any number in between. (RECORD ONE RESPONSE ONLY.)

10 - Excellent value	9	8	7	6	5	4	3	2	1 - Poor value	11 Don't Know (do Not Read)

1-4b. Using a scale of 1 to 10, where **1** means **not at all valuable** and **10** means **very valuable**, how valuable are each of the following from a transmission provider?

10 – very valuable	9	8	7	6	5	4	3	2	1 – Not at all valuable	11 Don't Know (do Not Read)

[RANDOMIZE ORDER OF OFFERING]

1-4b1 Capital Investment
1-4b2 Social Media Communication (i.e. Facebook, Twitter)
1-4b3 Power Quality
1-4b4 Electronic Data Interchange
1-4b5 Website
1-4b6 Engineering / Consulting Services
1-4b7 Customer Portal (Sharepoint)

1-5. Thinking now about your ability to access HYDRO ONE to discuss your questions or problems either over the phone or through a representative, are you very satisfied, somewhat satisfied, neither satisfied not dissatisfied, somewhat dissatisfied, or very dissatisfied?

Very satisfied	Somewhat satisfied	Neither satisfied nor dissatisfied	Somewhat dissatisfied	Or, very dissatisfied	Don't know (DO NOT READ)
5	4	3	2	1	x

1-6. Please think of what you expect the performance of a utility should be. For the next statements do you think HYDRO ONE performs much better than expected, somewhat better, just as expected, somewhat worse or much worse than expected. Let's start with… (INSERT FIRST QUESTION). REPEAT SCALE IF NECESSARY.

	Much better than expected	Somewhat better	Just as expected	Somewhat worse	Or, much worse than expected of a utility	Don't know (DO NOT READ)
.1 How well they maintain their electricity systems, including the towers, lines and stations	5	4	3	2	1	x
.3 The quality of the electricity you receive– that is always full power without fluctuations or momentary interruptions	5	4	3	2	1	x

1-7. Please indicate how much you agree or disagree with each of the following statements. To do this, please use a 1 to 10 scale, where a **1** means you **disagree completely**, and a **10** means you **agree completely**. You may use a 1, a 10 or any number in between to rate each statement.

	WRITE IN RATING

	(1 TO 10)
.1 You have a reliable supply of electricity	____________
.3 Hydro One is aware of the condition of the equipment that serves your business	____________
.20. Hydro One promptly delivers written documents such as memos, agreements or proposals when promised	____________
.5 Hydro One is fair.	____________
.6 Hydro One keeps commitments	____________
.8 Hydro One is concerned about their customers.	____________
.10 Hydro One has a flexible attitude towards your business	____________
.13 When asked, Hydro One is willing to provide information that is important to you	____________
.14 Hydro One is non-bureaucratic	____________
.15 Hydro One responds to customer questions promptly	____________
.16 Hydro One makes decisions promptly.	____________
If Q1-7.16 code 1 to 6 ask 1-7.16o. Which decisions are especially slow? **DO NOT CODE, ATTACH VERBATIMS TO INDIVIDUAL NAMES IN EXCEL**	____________
.18 Hydro One minimizes the number of power outages in your area	____________
.19 In negotiations, Hydro One considers the needs of both parties	____________
.23 They are financially well-managed	____________

Section 2: Power Outages

Planned outages section

Thinking about times when there was no electricity available …**FOR INDUSTRIALS/RETAIL SAY at your company … FOR LDC SAY at Hydro One delivery points…** due to planned outages when Hydro One needed to repair or replace equipment or upgrade service.

2-3a. In the past year, have you experienced any <u>power outages due to planned outages</u>, FOR INDUSTRIAL/RETAIL SAY at your company FOR LDC SAY at Hydro One delivery points?

Yes…………..1	
No…………..2	SKIP TO INTRO TO UNPLANNED OUTAGES Q 2-4a
Don't Know…3	Is there someone else in the company who can provide this information? Who is that person? ________________________________

2-3.3. How satisfied are you with the way Hydro One handles <u>planned outage</u>(s)? Would you say you are… (READ LIST)?

Very satisfied	Somewhat satisfied	Neither satisfied nor dissatisfied	Somewhat dissatisfied	Or, very dissatisfied	Don't know (DO NOT READ)	No contact (volunteered)
5	4	3	2	1	x	y

Unplanned outages

Thinking now about times when there was no electricity available … **FOR INDUSTRIALS/RETAIL SAY at your company …FOR LDC SAY at Hydro One delivery points** … due to <u>unplanned outages</u> that occurred on the facilities owned by Hydro One due to an accident, weather conditions or equipment failure.

2-4a. In the past year, have you experienced any <u>power outages due to unplanned outages</u>, …FOR INDUSTRIAL/RETAIL SAY at your company …FOR LDC, SAY at Hydro One delivery points?

Yes…………..1	
No…………...2	SKIP TO 2-5.1a Fluctuations
Don't Know…3	Is there someone else in the company who can provide this information? Who is that person? ________________________________

2-4.2 How satisfied are you with the way Hydro One handles <u>unplanned outage</u>(s)? Would you say you are… (READ LIST)?

Very satisfied	Somewhat satisfied	Neither satisfied nor dissatisfied	Somewhat dissatisfied	Or, very dissatisfied	Don't know (DO NOT READ)
5	4	3	2	1	x

Ask if Q2-4.2 code 1 or 2
2-4.2o. What are your most pressing issues with the way unplanned outages are handled? **DO NOT CODE, ATTACH VERBATIMS TO INDIVIDUAL NAMES IN EXCEL**

2-4.9 Now, using a 1 to 10 scale, where a 1 means you **disagree completely** and a 10 means you **agree completely**, please rate your e<u>xperience with the unplanned outage contact</u> on each of the following statements. You may use a 1, a 10, or any number in between to rate each statement.

	WRITE IN RATING (1 TO 10)
.3 They provide accurate information about the expected duration of the outage	________________
.4 They are forthcoming with the information they have about the outage	________________
.5 They restore power quickly following a power outage	________________

If score 1 to 6 in q2-4.9-4, ask:
2-4.9o What information has not been forthcoming?
Estimated time of restoration……………………………………1
Cause of outage……………………………………………………2
Other (specific)……………………………………………………x
____

Fluctuations

ASK ALL

2-5.1b. In the past year …**FOR INDUSTRIALS/RETAIL SAY** has **your company… FOR LDC SAY have Hydro One delivery points…** experienced READ LIST RECORD YES OR NO FOR EACH

	Yes…1	**No…2**	**Don't Know**
1. Transients			
2. Interruptions			
3. Sag / Undervoltage			
4. Swell / Overvoltage			
5. Waveform distortion			
6. Voltage fluctuations			
7. Frequency variations			

ASK ALL RESPONDENTS
2-5.5. Using a 1 to 10 scale, where a **1** means you **disagree completely** and a **10** means you **agree completely**, please rate the handling of <u>power quality and reliability problems</u> by Hydro One on each of the following statements.

	WRITE IN RATING (1 TO 10)
.1 Hydro One is proactive in identifying future sources of power quality and reliability problems	
.2 When requested, Hydro One conducts detailed analysis of their data to determine the root cause to learn how to improve your service	
.3 Hydro One works hard to minimize power quality issues	

Section 3: Communication

Please think now about written and verbal communications.

3-1. How satisfied are you with the way HYDRO ONE communicates with your company?

Very satisfied	Somewhat satisfied	Neither satisfied nor dissatisfied	Somewhat dissatisfied	Or, very dissatisfied	Don't know (DO NOT READ)
5	4	3	2	1	x

Ask if Q1 code 1 or 2
3-1o. What are your most pressing issues with the way Hydro One communicates with your company? **DO NOT CODE, ATTACH VERBATIMS TO INDIVIDUAL NAMES IN EXCEL**
____

Thinking now about Procedure and Policy Information, using a 1 to 10 scale, where a **1** means you **disagree completely** and a **10** means you **agree completely**, please rate the company on the statement.

	WRITE IN RATING (1 TO 10)
3-5.2 In meetings and presentations, the Hydro One procedure and policy information is explained well	________

How would you rate the following Procedure and Policy Information using a scale of 1 to 10 where **1** is **very poor** and **10** is **excellent**?

	WRITE IN RATING (1 TO 10)
3-5.3 The frequency of information on Hydro One procedure and policy	
3-5.4 The communication quality of procedure and policy information	

3-5 Think of what you expect the communications of a utility should be for the amount of information regarding procedures and policies, does HYDRO ONE perform ...**READ LIST?**

Much better than expected	Somewhat better	Just as expected	Somewhat worse	Or, much worse than expected of a utility	Don't know (DO NOT READ)
5	4	3	2	1	[ ]x

Section 4: Customer Relations / Account Executives

Now we would like to understand some of your contact experiences.

4-1. Which of the following business contacts do you have with HYDRO ONE? (CHECK ALL THAT APPLY). PAUSE AFTER EACH CONTACT FOR A RESPONSE

ONLY ASK THIS OF Dx or TxDx and LDC: The Hydro One Business Customer Centre	2

Operations customer support	3
Customer contracts	4
Hydro One web site	5
An Account Executive, this is your assigned person who you can contact if your company has a problem, to discuss an outage, to plan for new service or to ask questions about service, or who calls you	6
Other (SPECIFY)___________________________________	

ONLY ASK Q4-3 IF Dx or TxDx and LDC
ASK Q 4-3 IF Q4-1=2
4-3. How satisfied are you with the your most recent contact experience with the Business Customer Centre ~~agent~~?

Very satisfied	Somewhat satisfied	Neither satisfied nor dissatisfied	Somewhat dissatisfied	Or, very dissatisfied	Don't know (DO NOT READ)
5	4	3	2	1	x

4-3o. If Somewhat or Very Dissatisfied to Q4-3
Please give me (us) some examples of why you are not satisfied with the Business Customer Centre?
____

ONLY ASK Q4-31a IF Dx or TxDx and LDC
ASK Q 4-31a IF Q4-1=2
4-31a. Thinking about your dedicated Business Customer Centre agent that handles your <u>BILLING</u> inquiries. How satisfied are you with him or her for dealing with your billing inquiries? READ LIST

Very satisfied	Somewhat satisfied	Neither satisfied nor dissatisfied	Somewhat dissatisfied	Or, very dissatisfied	Don't know (DO NOT READ)	Not Applicable
5	4	3	2	1	x	x

4-31. If Somewhat or Very Dissatisfied to Q4-31a
Please give me (us) some examples of why you are not satisfied with your dedicated Business Customer agent?
____

IF Dx Industrial/Retail SKIP TO NEXT SECTION 5

If Tx or TxDx or any LDC ASK
Please think about your Account Executive at HYDRO ONE.

4-4**.** In the past year, have you been in contact with your Account Executive for any reason?
Yes....1 CONTINUE
No..... 2 SKIP TO SECTION 5

4-7. How satisfied are you with your most recent contact experience with your Account Executive?

Very satisfied	Somewhat satisfied	Neither satisfied nor dissatisfied	Somewhat dissatisfied	Or, very dissatisfied	Don't know (DO NOT READ)
5	4	3	2	1	x

4-8. Using a 1 to 10 scale, where a 1 means you **disagree completely** and a 10 means you **agree completely**, please rate your experience with your Account Executive on each of the following statements. Your Account Executive ...(READ LIST)

	WRITE IN RATING (1 TO 10)

.1 Is always available when you need him or her	_________
.2 Always returns your calls in a timely manner	_________
.3 Gets you the assistance you need quickly	_________
.4 Provides all the information you need when you call	_________
.5 Follows up to make sure your question or problem is resolved	_________
.6 Is knowledgeable about HYDRO ONE company policy	_________

Section 5: Billing

Ask FOR Dx LDC and TxDx LDC CUSTOMERS ONLY:

Next I'd like to know your opinion about HYDRO ONE'S bills.

5-1. How satisfied are you with the way HYDRO ONE handles its billing?

Very satisfied	Somewhat satisfied	Neither satisfied nor dissatisfied	Somewhat dissatisfied	Or, very dissatisfied	Don't know (DO NOT READ)
5	4	3	2	1	x

IF CODE 1,2 OR 3 TO Q5-1 ASK:

5-1o. What improvements would you like to see in the way Hydro One handles its billing?

____

Section 11: Final Comments

ASK ALL

11-1 Do you have any further comments that you would like to make? **DO NOT CODE, ATTACH VERBATIMS TO INDIVIDUAL NAMES IN EXCEL**

____

Section 8: Access Permissions

That completes our formal questions.

8-1. Hydro One Management is committed to better understanding their customer needs to improve the value that Hydro One can deliver to their customers. As such, they are asking for your permission to see the results of your specific interview in addition to the aggregate research results to help them better work toward meeting your company's specific needs. May we provide your responses to Hydro One management?

Yes....1 SKIP TO 8-2 No....2 CONTINUE

If no, ask

8-1a What are your particular concerns with providing permission? DO NOT CODE, PROVIDE VERBATIM RESPONSES

_________________________ SKIP TO END

8-2. May Hydro One Management provide your responses to your Account Executive to review and set up a follow-up meeting with you?

Yes...1 No....2

Remember, we will only share your responses with Hydro One if you responded "YES" to the previous questions. If you responded "NO", we will not share your individual results with Hydro One. However, to verify your completion of the survey, please complete the following information...

Thank you very much for your participation.

Tx GENERATOR CUSTOMER SCREENER

2011

Time Started:________________	Time Completed:_____________	Elapsed Time:_________
Name:____	Telephone: (_______)_______________________	
Company Name:__________________________________	Title:______________________________	
Address:____		
City:________________________	Province/State:_______	Postal/Zip Code:__________________
Interviewer:____	Date:_______________________	

Sample:
Tx Generator 7
Tx/Dx Generators (separate questionnaire)... 9

NOTE TO ALL: Screeners and W1 and W2 Method are all changed in 2010.

W1 E-mail Review Invitation and Link By Hydro One using IntelliPulse PINs

W1 Telephone Review Reminder By Hydro One Account Exec from List provided by IntelliPulse -

- Provide Review method choice to IntelliPulse

I am calling because IntelliPulse has indicated that you haven't had the opportunity to complete the on-line Satisfaction evaluation yet.

A. You have a few options for how you want to complete this evaluation. I can record how you would like to respond and let IntelliPulse know your preference. They can call you over the telephone, you have the email with the web site link so you can log onto the questionnaire and complete it online, or IntelliPulse can fax, or e-mail the questionnaire to you. Which would you prefer?

CIRCLE ONE:

Telephone .1	Do you have a particular date and time that you would like to book the Review with IntelliPulse, or have IntelliPulse call you to set a time for the Review? RECORD Date: ________________ Time: _____________a.m./p.m.
Web 2	Do you need me to re-send the original email to you? CONFIRM: e-mail address: .... If IntelliPulse hasn't received you completed Review by April 20, they will call you to complete it by telephone.
Fax 3	OBTAIN FAX NUMBER ( ) IntelliPulse will fax the questionnaire to you, along with a fax number for you to return your completed opinions. They will send the fax to you in the next couple days. If IntelliPulse hasn't received you completed Review by April 20, they will

	call you to complete it by telephone.
e-mail 5	OBTAIN e-mail ADDRESS: .... IntelliPulse will e-mail the questionnaire to you in the next couple of days. Once you receive it, would you please print it and then fax your opinions back to IntelliPulse. The fax number will be in the e-mail.
Refuse.........6	**IF REFUSES SPRING ASK:** A. May we send the questionnaire to you in the Fall or can IntelliPulse call you in the Fall and have you answer the questions at that time? No ....1 ask B Email web link in Fall.........................2 Telephone call in Fall 3
	B. IF REFUSES FALL ALSO, ASK: Would you allow IntelliPulse to call you to ask you to answer one single question on your overall satisfaction with Hydro One? **Note: IntelliPulse must make this call and obtain the score, the AE is not allowed to collect it.** Do you have a particular date and time that I can tell IntelliPulse to call you? RECORD Date: ________________ Time: ______________a.m./p.m.
Do not call again..........8	IF RESPONDENT ABSOLUTELY REFUSES AND STATES NEVER TO BE CALLED AGAIN, THANKS AND RECORD AND LOG ON PERMANENT REFUSAL LIST

THANK RESPONDENT AND REPEAT WHAT STEPS THEY HAVE CHOSEN AS A CONFIRMATION.

On-line version Introduction:
Hydro One commissioned IntelliPulse Inc., a Canadian research firm to conduct the 2010 customer satisfaction research.

Hydro One believes building a strong relationship with their customers is of prime importance. Collecting feedback from you is key to help understand your needs and get input on your current relationship with Hydro One.

For this review, please keep your organization's TRANSMISSION service in mind, not your residential electricity service.

B. Hydro One appreciates the time you spend and the feedback you provide. The review takes about 16 minutes depending on your answers.

Telephone Review Call to On-line non-completes by IntelliPulse:

Hello, I'm ___________________ calling on behalf of HYDRO ONE. I am from IntelliPulse, a Canadian market research firm. May I please speak with (INSERT NAME)?

(ARRANGE CALLBACK AS NEEDED. IF RESPONDENT NOT AVAILABLE, BUT HAS VOICE MAIL OR OTHER MESSAGE SYSTEM, LEAVE A MESSAGE THAT YOU ARE CALLING ABOUT THE REVIEW THEY WERE ASKED TO PARTICIPATE IN BY HYDRO ONE [THEY SHOULD HAVE RECEIVED A LETTER FROM THEIR ACCOUNT EXECUTIVE], LEAVE YOUR NAME AND MESSAGE THAT YOU WILL CALL BACK. LEAVE NO MORE THAN 2 OR 3)

DAY	DATE	TIME		DAY	DATE	TIME

CALLBACK #1				#11			
CALLBACK #2				#12			

(WHEN CONNECTED TO PERSON, CONTINUE.)

Your company should have received a letter and a telephone call from Hydro One about my call. Hydro One's goal is to achieve a superior level of customer service and they need feedback from customers like you. We're conducting a customer satisfaction review for them and would like to include your opinions. May I continue? (IF NECESSARY SAY; please let me assure you that we are not selling anything. Your answers are completely confidential and will be used for research purposes only.)

Telephone .1	IF RESPONDENT CANNOT CONTINUE NOW, ASK FOR DATE AND TIME WHEN YOU CAN CALL BACK AND FINISH THE REVIEW. Date: _______________ Time: _____________a.m./p.m.

C. Hydro One appreciates the time you spend and the feedback you provide. The evaluation takes about 16 minutes depending on your answers.

D. May I please proceed with asking you the questions and getting your answers over the telephone?
Yes …. START AT INTRODUCTION JUST BEFORE SECTION 1.
No….. IF RESPONDENT REFUSES TO ANSWER THE QUESTIONNAIRE, CONTINUE

E. Would it be alright to contact you in the fall to complete the review?
Yes … CONTINUE TO F
No …. RESPONDENT **NOT** TO BE CONTACT, GO TO QG

F. Would you prefer to be contacted by email with a website link or should I telephone you in the fall?
Web link …1
Telephone..2

RECORD W2 CONTACT METHOD. IN W2, RESPONDENT IS CONTACTED ONLY IN THEIR SELECTED WAY IN THE FALL.

Thank you. We will call/email you in September to complete the review at that time.

G. Would you be willing to tell me … Q12A AND READ QUESTION and RECORD ANSWER.

1-2a. How satisfied are you with HYDRO ONE overall? Would you say you are… (READ LIST)?

Very satisfied	Somewhat satisfied	Neither satisfied nor dissatisfied	Somewhat dissatisfied	Or, very dissatisfied	Don't know (DO NOT READ)
5	4	3	2	1	x

IF RESPONDENT ANSWERED Q12A ONLY, SKIP TO Q8.1 AND 8.2 AND RECORD ANSWERS.
Respondent is considered a complete and does NOT get put into the W2 sample

For this questionnaire, please keep your organization's transmission service in mind, not your residential electricity service.

Section 1: Overall Impressions of HYDRO ONE

Please think about your overall impressions of HYDRO ONE, the company that provides transmission connection to the specific business site(s) you have operational responsibility for in regards to electricity service.

11. Please rate your overall impression of the company on a one to ten scale, where **1** means your impression is **very unfavourable** and **10** means **very favourable**. You may use a 1, a 10, or any number in between.

Very unfavourable									Very favourable	Don't know (DO NOT READ)
1	2	3	4	5	6	7	8	9	10	11

12a. How satisfied are you with Hydro One overall? Would you say you are… (READ LIST)?

Very satisfied	Somewhat satisfied	Neither satisfied nor dissatisfied	Somewhat dissatisfied	Or, very dissatisfied	Don't know (DO NOT READ)
5	4	3	2	1	x

11a. What is the main issue that Hydro One could address to meet your business needs? **DO NOT READ – DO NOT SHOW PRECODES ON WEB QUESTIONS OR ON PAPER QUESTIONNARIE**

Communications/proactive phone calls
Reliability
Accessibility
Directory of contacts
Cost
Other specify ____________________

13. There are a number of utility companies that provide service such as the gas company and the phone company. Think of what you expect the performance of a utility should be. In general do you think HYDRO ONE performs much better than expected, somewhat better, just as expected, somewhat worse or much worse than expected of a utility?

Much better than expected	Somewhat better	Just as expected	Somewhat worse	Or, much worse than expected of a utility	Don't know (DO NOT READ)
5	4	3	2	1	x

1-4b. Using a scale of 1 to 10, where **1** means **not at all valuable** and **10** means **very valuable**, how valuable are each of the following from a transmission provider?

10 – very valuable	9	8	7	6	5	4	3	2	1 – Not at all valuable	11 Don't Know (do Not Read)

[RANDOMIZE ORDER OF OFFERING]

1-4b1 Capital Investment
1-4b2 Social Media Communication (i.e. Facebook, Twitter)
1-4b3 Power Quality
1-4b4 Electronic Data Interchange

1-4b5 Website
1-4b6 Engineering / Consulting Services
1-4b7 Customer Portal (Sharepoint)

15. Thinking now about your ability to access HYDRO ONE to discuss your questions or problems either over the phone or through a representative, are you very satisfied, somewhat satisfied, neither satisfied nor dissatisfied, somewhat dissatisfied, or very dissatisfied?

Very satisfied	Somewhat satisfied	Neither satisfied nor dissatisfied	Somewhat dissatisfied	Or, very dissatisfied	Don't know (DO NOT READ)
5	4	3	2	1	x

16. Please think of what you expect the performance of a utility should be for INSERT STATEMENT. Do you think HYDRO ONE performs much better than expected, somewhat better, just as expected, somewhat worse or much worse than expected.

	Much better than expected	Some-what better	Just as expected	Some-what worse	Or, much worse than expected of a utility	Don't know (DO NOT READ)
1. How well they maintain their electricity systems, including the towers, lines and stations	5	4	3	2	1	x

17. Please indicate how much you agree or disagree with each of the following statements. To do this, please use a 1 to 10 scale, where a **1** means you **disagree completely**, and a **10** means you **agree completely**. You may use a 1, a 10 or any number in between to rate each statement.

	WRITE IN RATING (1 TO 10)
1. You have a reliable transmission connection	____________
20. Hydro One promptly delivers written documents such as memos, agreements or proposals when promised	____________
5 Hydro One is fair	____________
6 Hydro One keeps commitments	____________
8. Hydro One is concerned about their customers	____________
10. Hydro One has a flexible attitude towards your business	____________
12. Hydro One staff is knowledgeable about transmission connection reliability needs of your company	____________
13. When asked, Hydro One is willing to provide information that is important to you	____________
14. Hydro One is non-bureaucratic	____________
15. Hydro One responds to customer questions promptly	____________
16. Hydro One makes decisions promptly	____________
If Q1-7.16 code 1 to 6 ask 1-7.16o. Which decisions are especially slow? **DO NOT CODE, ATTACH**	____________

VERBATIMS TO INDIVIDUAL NAMES IN EXCEL	
18. Hydro One minimizes the number of outages in your area	________________
19. In negotiations, Hydro One considers the needs of both parties	________________

Section 2: Power Outages

Planned outages

Thinking about times when your Hydro One delivery point(s) was not available due to planned outages when HYDRO ONE needed to repair or replace equipment or upgrade service.

23a. In the past year, have you experienced any generation outages due to planned outages on your Hydro One delivery points(s) at your company?

Yes…………..1	
No…………...2	SKIP TO INTRO TO UNPLANNED OUTAGES Q2.24a
Don't Know…3	Is there someone else in the company who can provide this information? Who is that person? ___________________________________

233. How satisfied are you with the way HYDRO ONE handles planned outage(s)? Would you say you are… (READ LIST)?

Very satisfied	Somewhat satisfied	Neither satisfied nor dissatisfied	Somewhat dissatisfied	Or, very dissatisfied	Don't know (DO NOT READ)
5	4	3	2	1	x

Unplanned outages

Thinking now about times when your Hydro One delivery point(s) was not available due to unplanned outages that occurred on the facilities owned by Hydro One due to an accident, weather conditions or equipment failure.

24a. In the past year, have you experienced any generation outages due to unplanned outages on your Hydro One delivery point(s) at your company ?

Yes…………..1	
No…………...2	SKIP TO Q2.55
Don't Know…3	Is there someone else in the company who can provide this information? Who is that person? ___________________________________

242. How satisfied are you with the way HYDRO ONE handles unplanned outage(s)? Would you say you are… (READ LIST)? Would you say you are… (READ LIST)?

Very satisfied	Somewhat satisfied	Neither satisfied nor dissatisfied	Somewhat dissatisfied	Or, very dissatisfied	Don't know (DO NOT READ)
5	4	3	2	1	x

Ask if Q2.42 code 1 or 2 or 3

242o. What are your most pressing issues with the way outages are handled? **DO NOT CODE, ATTACHED VERBATIMS TO INDIVIDUAL NAMES IN EXCEL**

____

249 Now, using a 1 to 10 scale, where a 1 means you **disagree completely** and a 10 means you **agree completely**, please rate your experience with the unplanned outage contact on each of the following statements. You may use a 1, a 10, or any number in between to rate each statement. [ANALYST CROSS Q249 BY 246]

	WRITE IN RATING (1 TO 10)
3. They provide accurate information about the expected duration of the outage	________________
4. They are forthcoming with all the information they have about the outage	________________
5. They restore your transmission connection quickly following a power outage	________________

IF 2494 SCORE IS LESS THAN 7 ASK:

Q294O. What information has not been forthcoming?

____

ALL WHO HAD UNPLANNED OUTAGE

Customer Briefings

250a. A Customer Briefing is a formal written account of an incident showing timelines, analysis and follow up recommendations. Have you received any Customer Briefings from Ontario Grid Control in the past year?

Yes	1- **continue**
No	2– **skip to FLUCTUATIONS**

250b. How satisfied are you with **Customer Briefings** of incidents? Are you

Very satisfied	Somewhat satisfied	Neither satisfied nor dissatisfied	Somewhat dissatisfied	Or, very dissatisfied	Don't know (DO NOT READ)
5	4	3	2	1	x

Fluctuations

ASK ALL RESPONDENTS

2-5.5. Using a 1 to 10 scale, where a **1** means you **disagree completely** and a **10** means you **agree completely**, please rate the handling of power quality and reliability problems by Hydro One on each of the following statements.

	WRITE IN RATING (1 TO 10)
.1 Hydro One is proactive in identifying future sources of power quality and reliability problems	
.2 When requested, Hydro One conducts detailed analysis of their data to determine the root cause to learn how to improve your service	
.3 Hydro One works hard to minimize power quality issues	

Section 3: Communication

Please think now about written and verbal communications.

31. How satisfied are you with the way Hydro One communicates with your company?

Very satisfied	Somewhat satisfied	Neither satisfied nor dissatisfied	Somewhat dissatisfied	Or, very dissatisfied	Don't know (DO NOT READ)
5	4	3	2	1	x

Ask if Q1 code 1 or 2 or 3

31o. What are your most pressing issues with the way Hydro One communicates with your company? DO NOT CODE, ATTACHED VERBATIMS TO INDIVIDUAL NAMES IN EXCEL

____

34. Using a 1 to 10 scale, where a **1** means you **disagree completely** and a **10** means you **agree completely**, please rate the WRITTEN communications from the company the following statement.

	WRITE IN RATING (1 TO 10)
3. In meetings and presentations, the procedure and policy information is explained well	________

35. How would you rate the following Procedure and Policy Information using a scale of 1 to 10 where **1** is **very poor** and **10** is **excellent**?

	WRITE IN RATING (1 TO 10)
3-5.3 The frequency of information on Hydro One procedure and policy	
3-5.4 The communication quality of procedure and policy information	

Section 4: Customer Business Relations / Account Executives

Now we would like to understand some of your contact experiences.

41. Which of the following business contacts do you have with Hydro One? (CHECK ALL THAT APPLY). PAUSE AFTER EACH CONTACT FOR A RESPONSE

An Account Executive in Customer Business Relations (this is your assigned person who you can contact if your company has a problem, to discuss an outage, to plan for new service or to ask questions about service, or who calls you)	6
Operations customer support	3
Hydro One web site	5
Other (SPECIFY)_____________________________________	

ASK IF AE CODE 6 IN Q41 otherwise skip to next section

47. How satisfied are you with the your most recent contact experience with your Account Executive?

Very satisfied	Somewhat satisfied	Neither satisfied nor dissatisfied	Somewhat dissatisfied	Or, very dissatisfied	Don't know (DO NOT READ)
5	4	3	2	1	x

4-8. Using a 1 to 10 scale, where a 1 means you **disagree completely** and a 10 means you **agree completely**, please rate your experience with your Account Executive on each of the following statements. Your Account Executive …(READ LIST)

	WRITE IN RATING (1 TO 10)
1 Is always available when you need him or her	
2. Always returns your calls in a timely manner	_________
3. Gets you the assistance you need quickly	_________
4. Provides all the information you need when you call	_________
5. Follows up to make sure your question or problem is resolved	_________
6 Is knowledgeable about HYDRO ONE company policy	_________

Section 11: Final comments

ASK ALL

11-1 Do you have any further comments that you would like to make? **DO NOT CODE, ATTACHED VERBATIMS TO INDIVIDUAL NAMES IN EXCEL**

____
____

Section 8: Access Permissions

That completes our formal questions.

8-1. Hydro One Management is committed to better understanding their customer needs to improve the value that Hydro One can deliver to their customers. As such, they are asking for your permission to see the results of your specific interview in addition to the aggregate research results to help them better work toward meeting your company's specific needs. May we provide your responses to Hydro One management?

Yes….1 SKIP TO 8-2	No….2 CONTINUE

If no, ask

8-1a What are your particular concerns with providing permission? DO NOT CODE, PROVIDE VERBATIM RESPONSES

____________________________ SKIP TO END

8-2. May Hydro One management provide your responses to your Distribution Account Executive to review and set up a follow-up meeting with you?

Yes….1	No….2

Online ending:

Remember, we will only share your responses with Hydro One if you responded "YES" to the previous question.

If you responded "NO", we will not share your individual results with Hydro One.

However, to verify your completion of the survey, please complete the following information...

Thank you very much for your participation.

Date of interview

PROGRAMMER: BE SURE TO APPEND **ALL DATA** FROM THE CUSTOMER SAMPLE FILE TO THE INTERVIEW RECORD EXCEPT THOSE THAT IDENTIFY THE CUSTOMER SUCH AS NAME, PHONE NUMBER, ACCOUNT NUMBER.

<u>School Energy Coalition (SEC) INTERROGATORY #31 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>

[D1-1-2/p.1]
Please provide year-to-date actuals for Table 1.

<u>Response</u>

The amount of in-service capital additions recorded as of June 31, 2012 was $744 million.

	YTD June 2012
	ISA Actual
Sustaining	102
Development	625
Operations	3
Other	14
Total	**744**

School Energy Coalition (SEC) INTERROGATORY #32 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

[D1-3-3-B]
Has the Applicant provided a response to the OPA regarding its January 11, 2012 letter? If so, please detail the response and provide a copy of any correspondence to the OPA.

Response

Yes, Hydro One has advised the OPA that it will begin to incur capital expenditures for this project. These funds are for development work required to conduct engineering design for detailed cost estimating and preparation of tendering documents, and to perform environmental approvals work in 2012 to meet the required in-service date of spring 2015. A letter from Hydro One to the OPA dated June 18, 2012 is provided in Attachment 1.

Hydro One Networks Inc.
483 Bay Street
South Tower, 4th floor
Toronto, ON M5G 2P5
www.HydroOne.com

Tel: (416) 345-5444
Fax: (416) 345-4325

Mike Penstone
Vice President
Transmission Projects Development

June 18, 2012

Mr. Amir Shalaby
Vice President, Power System Planning
Ontario Power Authority
120 Adelaide Street West,
Toronto, ON M5H 1T1

Re: "Clarington" TS: Commitment of Full Project Development Work

Dear Amir,

This is with reference to your letters of October 3, 2011 and January 11, 2012 asking Hydro One to work towards providing additional 500/230kV auto-transformation capacity in the GTA East Area by Spring 2015 in preparation for the potential retirement of the Pickering Nuclear Generating Station (NGS). Your letter of January 11, 2012 also asked that the OPA be advised prior to making any major capital expenditure.

Hydro One has initiated project development work for a new station ("Clarington" TS) to be built on Hydro One lands at the Oshawa Area Jct. site. Planning specifications for Clarington TS have now been produced and $19.3M has been committed to complete project development work in order to meet the required in-service date.

The development phase will establish a comprehensive work scope, develop detailed cost estimates, conduct engineering design and carry out the necessary environmental approvals work for Clarington TS. This work is expected to be complete by end of this year so that project approval from the Hydro One Board can be sought in January 2013. Construction must begin in early 2013 if we are to meet the spring 2015 in-service date. As a result, a significant portion of the project engineering will be done during the development phase to enable the timely preparation of complete design and tendering documents.

We will provide you with an update on the cost, schedule and project risks prior to seeking Hydro One Board approval. We will also advise you if significant issues arise during the development work phase that may adversely impact the project schedule. We expect to provide further information on the cost impacts and additional risks to Hydro One of deferring work beyond certain critical milestones (including issuing tenders and awarding project construction contracts) by the end of September 2012.

Hydro One is committed to meeting the challenge of building a new major 500/230kV station to meet the requested tight timelines requested and have deployed significant resources to this project during a period of tremendous activity. Please advise Hydro One as soon as possible should the OPA receive new information that will affect the timing for this project.

Yours very truly,

Mike Penstone

Mike Penstone
Vice President – Transmission Projects Development
Hydro One Networks Inc.

cc: Bing Young, Director, Transmission System Development, Hydro One

School Energy Coalition (SEC) INTERROGATORY #33 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

[A-13-1/A/p.1]
Please provide details on how the Applicant calculated the Tx cost escalations for 'Construction' and 'Operations & Maintenance'.

Response

Hydro One does not calculate the Transmission Cost Escalation for Construction or the Transmission Cost Escalation for Operations and Maintenance. These values are taken from the IHS Global Insight Power Planner Report. Details on this escalator are available at Exhibit A, Tab 15, Schedule 1.

School Energy Coalition (SEC) INTERROGATORY #34 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

[A-14-1/p.5]
Please explain why the turn-key GIS station for the Hearn SS has a higher than expected cost?

Response

Please see Interrogatory Response in Exhibit I, Tab 22, Schedule 13.04 AMPCO 15.

Consumers Council of Canada (CCC) INTERROGATORY #28 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 A /T ab 15 /Sch 6/ p 14

HONI has provided a schedule setting out the level of outsourcing for work programs and transmission projects for the period 2010-2014. The amount goes from $132 million to $348 million in 2014. Why has the level of outsourcing significantly increased in 2013 and 2014? What type of assessment does HONI undertake to determine what is more cost-effective, the use of employees or outsourcing?

Response

Hydro One's outsourcing strategy ensures that sufficient resources are available, internal and external, to execute the work. The growth in the level of outsourcing reflects the planned increased outsourcing requirements to successfully carry out the necessary growth in the capital work program over this period.

Hydro One optimizes the contracting of work by assessing the planned work program and its forecasted resource requirements, assessing projects for suitability for contracting giving due consideration to cost effectiveness, resource skills, and internal resource work load; and balancing the optimal use of internal and contracted resources to execute the programs and projects.

Hydro One has been outsourcing project and program work on a regular basis for several years. This has included engineering work packages, construction work packages and turnkey projects. For example;

- Engineering work packages have been awarded to qualified engineering consultants on a competitive basis. Outsourcing assignments have been rated in terms of the level of effort required for Hydro One to manage the contractor's involvement in comparison with what it would have required for Hydro One to complete the job internally. The benefit to Hydro One is increased capacity without having made long term employment commitments.

- Construction work packages have been outsourced for two of four new greenfield DESN stations built over the past two and a half years.

- Five turnkey SVC (Static Var Compensator) projects and one turnkey SCB (Shunt Capacitor Bank) project have been awarded on a competitive basis. In these instances we did not have the experience to do the detailed design of the core systems, and turnkey was an attractive option.

Going forward, the outsourcing assessment is based on what has been learned over the past few years from our experience outsourcing, and based on internal capacity. For example:

- Basic Engineering that defines requirements and determines the standards to which a job is built is best done by Hydro One staff. This ensures consistency and repeatability from project to project and is communicated by way of a Project Definition Report (PDR).

- Production of the detailed design from the PDR is work available to be completed by external contractors for greenfield and brownfield reconstruction projects. They have the skills and allow Hydro One to get the work done at a competitive cost with a variable workforce.

- Production of the detailed design from the PDR is best done internally for sustainment program work where record drawings may not be completely up to date and/or where the requirements will not become fully understood until the work is under way. Contractors are not as cost effective in these instances due to the advantage Hydro One's internal workforce has as a result of having worked in these stations before and having a corporate memory.

- Greenfield and large brownfield construction work, including lines, stations and underground cable installations, that can be defined well enough to attract good competitive pricing from qualified and experienced contractors, is considered for outsourcing.

- New DESN stations, SVC and SCB projects, on a full or partial turnkey basis, are considered good outsourcing opportunities.

Consumers Council of Canada (CCC) INTERROGATORY #29 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

(Ex. D1/T3/S1/p. 2) Please recast Table I to include Board approved amounts for 2009-2012.

Response

Please refer to Exhibit I, Tab 5, Schedule 10.07 CCC 14

Consumers Council of Canada (CCC) INTERROGATORY #30 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

(Ex. D1/T3/S1/p. 4) In 2011 HONI's capital Expenditures were $313 million below the Board approved levels. What was the impact of that reduction in spending on net income?

Response

A reduction in spending in capital expenditures does not directly impact net income. In-service additions to the rate base are the drivers in the determination of revenue requirement and net income, not capital expenditures. For 2011, actual in-service additions were, per Exhibit D1, Tab 1, Schedule 2, $42.6 million below Board-approved. As only half of in-service additions is recognized in rate base in that particular year, the rate base impact is $21.3 million and the resulting impact on regulatory net income after taxes is $823 thousand.

Consumers Council of Canada (CCC) INTERROGATORY #31 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

(Ex D1/T3/S1/p. 6) In 2012 HONI is forecasting that it will spend approximately $19.6 million less than forecast. Please provide the most recent forecast of what HONI expects to spend in 2012.

Response

Please see blue page update of Exhibit D1, Tab 3, Schedule 1, page 6, Table 3 filed on August 15, 2012.

Consumers Council of Canada (CCC) INTERROGATORY #32 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

(Ex. D2/T2/SI/p. I) Please recast Schedule I to include Board approved levels for 2009-2012.

Response

	2009		**2010**		**2011**		**2012**	
Transmission Capital ($ millions)	OEB Approved	Actual	OEB Approved	Actual	OEB Approved	Actual	OEB Approved	Bridge
Sustaining								
Transmission Stations								
Circuit Breakers	12.5	16.6	21.1	29.6	23.0	29.2	24.3	18.4
Station Reinvestment	64.6	34.6	43.5	17.9	81.1	36.4	81.8	78.9
Power Transformers	50.6	48.7	62.5	106.8	60.6	81.1	62.7	111.4
Other Power Equipment	12.0	13.1	21.6	13.9	19.0	16.2	20.5	25.1
Ancillary Systems	13.6	6.0	17.2	13.3	17.5	13.5	17.7	17.4
Stations Environment	4.3	3.0	3.7	4.0	8.3	7.0	8.4	5.8
Protection, Control, Monitoring, and Telecommunications	39.2	82.0	64.9	66.8	91.8	61.6	105.4	87.2
Transmission Site Facilities and Infrastructure	12.1	20.1	13.2	32.3	25.9	21.7	25.9	27.6
Total Transmission Stations Capital	208.8	224.1	247.7	284.7	327.3	266.5	346.7	371.9
Transmission Lines								
Overhead Lines Refurbishment and Component Replacement	49.1	56.8	53.4	54.0	54.0	52.4	56.0	52.0
Transmission Lines Reinvestment	16.5	15.2	16.1	16.2	8.7	17.1	7.1	11.3
Underground Lines Cable Refurbishment & Replacement	5.6	4.1	4.4	1.4	22.1	1.0	21.5	3.6
Total Transmission Lines Capital	71.2	76.0	74.0	71.6	84.8	70.6	84.6	66.8
Total Sustaining Capital	279.9	300.1	321.6	356.3	412.1	337.1	431.3	438.8

	2009		2010		2011		2012	
Development	OEB Approved	Actual	OEB Approved	Actual	OEB Approved	Actual	OEB Approved	Bridge
Inter Area Network Transfer Capability	389.0	343.1	497.1	392.8	319.8	269.1	169.4	114.6
Local Area Supply Adequacy	101.3	93.7	50.4	58.5	145.8	57.5	98.3	97.6
Load Customer Connection	39.0	54.4	54.1	33.8	78.0	51.1	80.7	67.2
Generator Customer Connection	6.0	4.5	23.1	3.9	0.0	0.1	0.0	0.7
Performance Enhancement & Risk Mitigation	7.2	19.2	14.2	19.6	23.0	19.0	6.9	19.8
TS Upgrades to Facilities Distribution Generation	0.0	0.2	0.0	12.5	33.8	10.3	81.4	13.2
P&C Enablement for Generation Connections	0.0	0.9	0.0	2.1	1.2	3.1	5.3	1.4
Smart Grid	3.5	0.0	3.4	0.0	7.8	5.8	6.8	7.0
Total Development	545.9	515.9	642.3	523.1	609.4	415.9	448.8	321.5
Operations								
Grid Operating and Control Facilities	15.1	11.3	9.8	3.6	22.2	3.7	18.1	7.0
Operating Infrastructure	3.1	8.7	19.1	4.0	21.3	5.0	38.2	18.9
Total "Operations"	18.2	20.0	28.9	7.6	43.5	8.8	56.4	25.9
Shared Services and Other Costs								
Transport, Work & Service Equipment	14.5	14.0	16.2	17.1	21.6	13.1	16.8	16.2
Information Technology (including Cornerstone)	61.5	60.1	40.6	24.7	17.9	32.9	12.5	34.2
Facilities & Real Estate	16.3	6.3	7.9	7.6	22.0	3.9	17.7	13.3
Other (including CDM)	0.2	1.4	0.1	(0.2)	(3.2)	(1.5)	(2.1)	0.0
Total Shared Services & Other Costs	92.4	81.8	64.8	49.1	58.4	48.4	44.8	63.7
Total Transmission Capital	**936.5**	**917.8**	**1,057.6**	**936.1**	**1,123.4**	**810.2**	**981.3**	**850.0**

Toronto Hydro-Electric System Limited (THESL) INTERROGATORY #6 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/Tab 3/Sch 1/Table 1, Table 2, Table 3

a) Please indicate the amount of the historic, bridge and test year amounts for Sustaining, Development, Operations, and Shared Services Capital that were spent and will be spent within the municipal boundaries of Toronto in each of Tables I, 2 and 3.

Response

Sustaining and Development Capital expenditures within the municipal boundaries of Toronto are provided in Table 1 below. The 2011 and 2012 Capital expenditures within the municipal boundaries of Toronto against the Board approved amounts are provided in Tables 2 and 3 respectively. Shared Services and Operations Capital is related to expenditures to support the general functioning of the business and operation of the transmission system. No specific expenditures are made for any particular municipality and therefore determination of what was spent in support of the assets within Toronto is not practical.

Table 1
Transmission Capital Expenditures in Toronto ($ Millions)

Capital Category	Historic			Bridge	Test	
	2009	2010	2011	2012	2013	2014
Sustaining	47.4	66.2	71.8	71.2	139.9	133.3
Development	18.7	16.2	26.6	64.3	100.1	41.2
Total	**66.1**	**82.4**	**98.4**	**135.5**	**240.0**	**174.5**

Table 2
2011 Capital Expenditures within Toronto – Actual vs. Board Approved ($Millions)

Capital Category	2011 Board Approved*	2011 Actuals	Variance
Sustaining	108.7	71.8	-36.9
Development	111.9	26.6	-85.3
Total	**220.6**	**98.4**	**-122.2**

*Amounts shown as Board Approved include the projects within the municipal boundaries of Toronto from the EB-2010-0002 proceeding.

Table 3
2012 Capital Expenditures within Toronto – Actual vs. Board Approved ($Millions)

Capital Category	2012 Board Approved*	2012 Bridge Forecast	Variance
Sustaining	105.7	71.2	-34.5
Development	79.4	64.3	-15.1
Total	**185.1**	**135.5**	**-49.6**

*Amounts shown as Board Approved include the projects within the municipal boundaries of Toronto from the EB-2010-0002 proceeding.

Toronto Hydro-Electric System Limited (THESL) INTERROGATORY #7 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

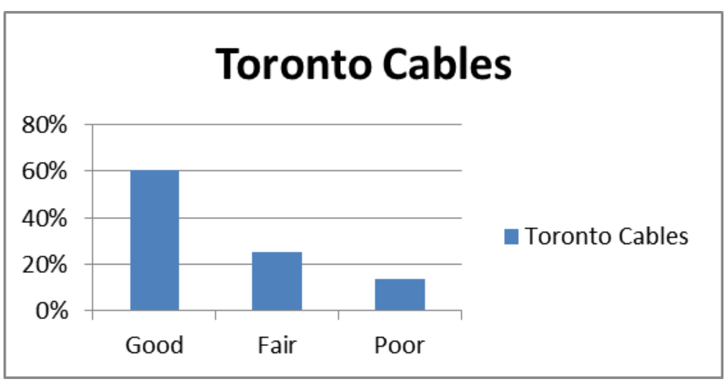
Ref: Exhibit Cl/Tab 2/Sch 2/ p34 1ines 16-18; p41 Fig 16

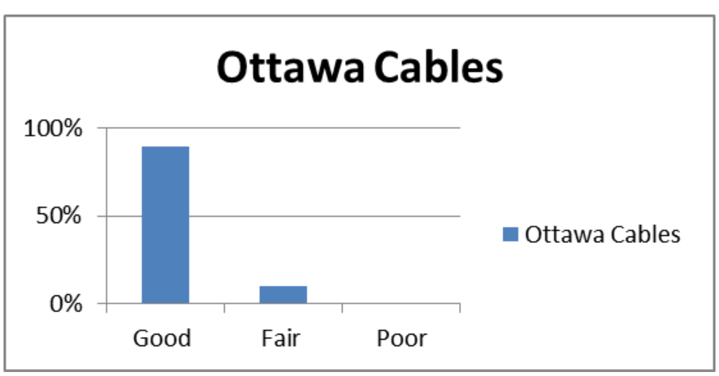
a) Please state what percentage of Hydro One's overall underground transmission cable population is in Toronto, Ottawa and Hamilton, respectively.
b) Please plot the cable health by category (as shown in Figure 16) for each of the cable populations in Toronto, Ottawa and Hamilton.
c) Please describe the planned cable replacement rate and cable investment strategy for each of Toronto, Ottawa and Hamilton.

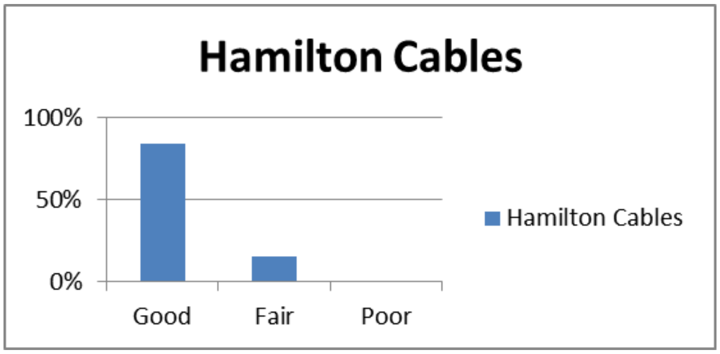
Response

a) The percentage of Hydro One's overall underground transmission cable population in Toronto, Ottawa and Hamilton are 55%, 13% and 10% respectively.

b) The requested graphs are shown below:







c) Hydro One's underground cable investment strategy is a provincial strategy.

Capital investments, such as the work covered under ISD# S62 from this application, are proposed when cable sections are approaching end of life. Investment decisions are based on several factors including condition, reliability and customer impact, consideration to equipment design considerations, operating history, and considerations to health, safety and environmental factors. Underground cable sections are monitored on a regular basis, and replacement projects are proposed as required based on these factors.

The proposed rate of replacement for 2012-2014 is an average of 3.7 kilometers per year based on the number of kilometers being addressed by the specific project. It is expected that on-going renewal of the provincial underground cables will be required beyond the test years.

Toronto Hydro-Electric System Limited (THESL) INTERROGATORY #8 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 C1/Tab 2/Sch 2 p40 Fig 14, Fig 15; p34 lines 16-17; p70 Fig 30, Fig 31

a) Please prepare a chart comparing the forced outage frequency of underground transmission cables for the period 2002 to 2011 (from Figure 14) with the forced outage frequency of line conductors for the period 2002 to 2011 (from Figure 30).
b) Please prepare a chart comparing the forced outage duration of underground transmission cables for the period 2002 to 2011 (from Figure 15) with the forced outage duration of line conductors for the period 2002 to 2011 (from Figure 31).
c) Please explain what Hydro One believes to be the appropriate relative performance of underground cables to line conductors in order to achieve "a high degree of reliability" for underground cables *as* stated in line 17 of p34?
d) What level of cable replacement would be required so that the forced outage frequency and forced outage duration of underground cables would be three and (separately) ten times better than that of line conductors?

Response

a & b)

In reference to parts a), and b), the question relates performance of an underground transmission cable system to a subcomponent of overhead transmission lines. Such a comparison would be misleading. Overhead transmission lines are composed of numerous sub-components (e.g. insulators, structures, shieldwire, hardware) each of which plays a role in their forced outage frequency and duration performance. Underground cable systems are composed of different subcomponents such as conductors, insulation, cable sheath, bushings, oil pressurization systems, etc.

The table below presents a direct comparison between the performance of Hydro One's 115/230 kV underground cable system to the 115/230 kV overhead line system from 2007 to 2011. The comparison demonstrates a higher level of performance for underground cables with fewer forced outages relative to overhead lines. Based on the Unavailability measure, the duration of forced outages on underground cables is typically greater relative to overhead lines. Approximately 90 % of the contribution to the unavailability of the underground cables was attributed to the two circuits that are being replaced within this application during the test years due to recurring oil leaks (refer to Exhibit D1, Tab 3, Schedule 2, Page 70 ISD# S62).

HV Cable and Overhead Line Forced Outage Performance

Hydro One-Owned Cable & Overhead Line Performance 2007 - 2011

Momentary and Sustained Outages

Voltage Class kV	HV Cable		Overhead Line	
	Frequency (#occ / yr /cct)	Unavailability (hr / yr / cct)	Frequency (#occ / yr /cct)	Unavailability (hr / yr / cct)
115 & 230 kV	0.54	64.9	1.3	19.3

c) Generally, underground cables are exposed to different conditions than those which challenge overhead transmission lines. For example, overhead transmission lines are frequently challenged by weather conditions while underground cables are more sheltered from weather effects. As a result, underground cables would be expected to perform better than overhead lines, thereby achieving "a high degree of reliability" for underground cables as stated on page 34 of the referenced exhibit.

d) Currently the frequency performance from 2007 to 2011 of our underground system is approximately 2.5 times better than the overhead system. Duration performance is more than 3 times worse than the overhead system. The performance of the underground system is expected to improve once the two cable circuits are replaced under this application (as per Exhibit D1, Tab 3, Schedule 2, page 70 ISD# S62), as approximately 90% of the contribution to underground cable unavailability is attributed to these two circuits.

Toronto Hydro-Electric System Limited (THESL) INTERROGATORY #9 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?

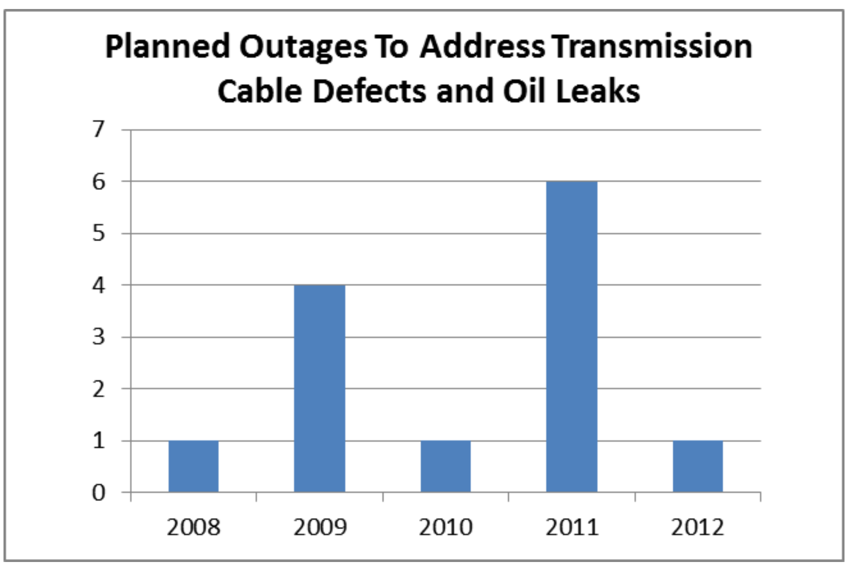
Interrogatory

Ref: Exhibit Cl/Tab 2/Sch 2/ p41 lines 1-4

a) Please plot, for HONI's entire underground transmission cable population, the number of defects and cable leaks that were addressed in planned outages from 2002 to 2011.
b) Please state if defects and cable leaks that did not lead to forced outages are considered as main factors in driving cable replacement. Please explain the reason why or why not.

Response

a) The graph below depicts the number of planned outages taken by year to address oil leaks and other defects on the entire underground cable population dating back to 2008. Outages taken for preventative maintenance activities and other program replacement work are not included. These details are not available prior to 2008.



b) Defects and cable leaks that do not lead to forced outages are considered and can be factors in driving cable replacement, in addition to other factors that are considered as described in the referenced exhibit. These are considered because depending on the number and severity of these defects/leaks they may be indicative of cable deterioration and impending problems with the cables, which could eventually lead to forced outages.

Toronto Hydro-Electric System Limited (THESL) INTERROGATORY #10 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 C1/Tab 2/Sch 2/ p41 lines 13-15

a) Please state the relative weight of circuit criticality, maintenance costs, forced outage frequency and environmental risks in making cable replacement decisions.
b) Please explain if the type of customer load (i.e., Residential, commercial, industrial), or the presence of public service customers (i.e., Hospitals) is used in determining circuit criticality?
c) Does Hydro One, in its current process, consider factors such as extent of high voltage and or distribution voltage back-up facilities, amount of load at risk, or length of time customers will remain in a single contingency state when making cable replacement decisions? If Hydro One does consider such factors, please explain how it does.

Response

a) Hydro One uses a health index assessment to evaluate its cable inventory. A risk analysis is also performed associated with reliability or criticality (including size of customer load), environment and economic impacts including maintenance costs. The result of this analysis is then used to determine the need for underground cable replacements.

b) The total customer load on a circuit and availability of backup supply are used in determining circuit criticality. Hydro One also works with its customers to understand their needs regarding their customers and takes these into consideration in making investment decisions.

c) Hydro One considers the risks of replacements of all assets including high voltage cables. This is done through our system design, investment planning process, assessment of project and construction alternatives and outage planning processes.

Association of Major Power Consumers in Ontario (AMPCO) INTERROGATORY #10 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

Preamble:
The OEB filing guidelines for transmission and distribution applications requires a three year forecast of capital (test year plus two subsequent years (Sect 2.5.2.4)

a) Please provide the forecast capital expenditures for the third year.

Response

a) Section 2.5.2.4 indicates that the evidence must include an Asset Management Plan. Hydro One has done so at Exhibit A, Tab 13, Schedule 2.

Hydro One has provided the forecast expenditures for Bridge year 2012 and Test years 2013 & 2014.

Hydro One has also provided the forecast expenditures for the third year in the Business Plan filed in confidence in response to IR in Exhibit I, Tab 2, Schedule 3.01 EP 1.

School Energy Coalition (SEC) INTERROGATORY #35 List 1

Issue 13 **Are the proposed 2013 and 2014 levels of Shared Services and Other Capital Expenditures appropriate?**

Interrogatory

[D1-4-4/p.4]
Please provide a detailed breakdown of the Major and MFA expenditures for the Test Years.

Response

Projected Capital Expenditures		
	2013	**2014**
483 Bay (Tenant Improvements)	**16.6**	**16.6**
Major Capital	*12.1*	*12.1*
MFA	*4.5*	*4.5*
21 Enterprise (New OC) Belleville	**3.1**	
Major Capital	*2.7*	
MFA	*0.4*	
Kleinburg Lines Training	**3.9**	
Major Capital	*3.6*	
MFA	*0.3*	
Bolton OC (New)	**5.5**	**4.8**
Major Capital	*5.5*	*4.5*
MFA		*0.3*
320 South Edgeware (New Garage)	**1.3**	
Major Capital	*1.3*	
425 South Edgeware (New OC)	**3.9**	
Major Capital	*3.7*	
MFA	*0.2*	
Guelph OC (New)	**5.6**	**0.9**
Major Capital	*5.6*	*0.7*
MFA		*0.2*
Timmins OC (New)		**2.9**
Major Capital		*2.9*
Dryden OC & Garage		**7.6**
Major Capital		*7.6*
Owen Sound OC & Garage	**0.8**	**1.4**
Major Capital	*0.8*	*1.4*
Arnprior OC & Garage	**1.6**	**6.6**
Major Capital	*1.6*	*6.2*
MFA		*0.4*
Stayner OC (New)		**1.3**
Major Capital		*1.3*
Other capital sustainment projects	**1.8**	**2.0**

Consumers Council of Canada (CCC) INTERROGATORY #33 List 1

Issue 13 **Are the proposed 2013 and 2014 levels of Shared Services and Other Capital Expenditures appropriate?**

Interrogatory

(Ex. D1/T4/S1/p. 2) Provide the Board approved levels for the years 2009-2012 for Shared Services and Other Capital (Table 1)

Response

Please refer to Exhibit I, Tab 12, Schedule 10.05 CCC 32 for Board Approved Shared Services and Other Capital.

Consumers Council of Canada (CCC) INTERROGATORY #34 List 1

Issue 13 Are the proposed 2013 and 2014 levels of Shared Services and Other Capital Expenditures appropriate?

Interrogatory

(Ex. D1/T4/S2/p. 6) Please provide copies of HONI's policy regarding IT desktops, Laptops, Printers and Plotter. Please explain how HONI attempts to manage these costs in a cost-effective manner.

Response

HONI refreshes end user computing devices to maintain vendor support of hardware and software components. Devices are selected, maintained and optimized to meet non-functional requirements (performance/usability) for line of business applications. Where possible, end user computing devices are repurposed with memory upgrades to extend the lifecycle while remaining within application vendor's processing chip and memory chip requirements. Laptops/Tablets are refreshed every 3 to 4 years, while desktops are refreshed every 4 to 5 years. Printer/Plotter assets are purchased and maintained with standard 3 to 7 year warranties depending on size and function. HONI also has a requirement within our outsourced services to keep end user computing devices under vendor support.

Consumers Council of Canada (CCC) INTERROGATORY #35 List 1

Issue 13 **Are the proposed 2013 and 2014 levels of Shared Services and Other Capital Expenditures appropriate?**

Interrogatory

(Ex. D1/T4/S4/p. 4) What was the total projected cost of the Head Office and GTA Facilities improvements? Please provide detailed budgets for 2012-2014 setting out all expenditures.

Response

The total projected cost for head office improvements was $36.6M (not including landlord base building improvements) for major capital and $15.3M for MFA.

The following table summarizes the budget for head office improvements years 2012 – 2014.

	Bridge	**Test Years**	
in $M	**2012**	**2013**	**2014**
Engineering	0.2	0.6	0.6
Construction	2.8	11.5	11.5
MFA	0.8	4.5	4.5
Total	**3.8**	**16.6**	**16.6**

TAB 14

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<u>London Property Management Association (LPMA) INTERROGATORY #26 List 1</u>

Issue 15 Are the inputs used to determine the working capital component of the rate base and the methodology used appropriate?

<u>Interrogatory</u>

Ref: Exhibit D1, Tab 1, Schedule 3, Attachment 1

a) Table 9 indicates that approximately one-half of the utilities shown do not include interest expense in the calculation of the working capital allowance. Please explain why Navigant believes that the long-term interest cost should be included in the analysis when other utilities, including Union Gas and Enbridge, do not include this cost.

b) When asked if there was any impact on the lead/lag study associated with payment of long-term debt or short-term debt, Union Gas responded (EB-2011-0210, Exhibit J.B-2-2-1) that no, there is no impact. The explanation provided by Union indicated that debt was not a component of rate base but rather it was a method of funding rate base similar to equity. Interest payments are paid from the operations of the business and are not a required component of cash working capital.

Please comment on the Union response and indicate why Hydro One believes that it should include the cost of long-term debt in the cash working capital calculation.

c) Please explain why there is no component of cash working capital associated with the payment of dividends on equity. Please calculate the expense lead time associated with the payment of dividends for the 2010 year.

<u>Response</u>

a) Navigant cannot comment on studies which it did not prepare and does not have an opinion regarding if those studies should or should not have included long-term interest expense. We cannot comment on the filings of Union Gas, Enbridge or other utilities which did not include a long-term interest expense component to the working capital calculation.

Given the specific circumstances of Hydro One, Navigant believes that the practice of including long-term interest expense in the estimation of working capital is appropriate and properly reflects the cash flow needs of the company. Long-term interest expense is a legal obligation with a specific payment date like all other expenses of the utility.

b) Navigant cannot comment on the accuracy of a study they did not prepare or the testimony in a proceeding in which we were not an active participant.

c) Cash Working Capital calculations are limited to expense accounts for the utility. Dividends are not an expense account.

London Property Management Association (LPMA) INTERROGATORY #27 List 1

Issue 15 **Are the inputs used to determine the working capital component of the rate base and the methodology used appropriate?**

Interrogatory

Ref: Exhibit D1, Tab 1, Schedule 3, Attachment 1 & Exhibit B2, Tab 1, Schedule 2

a) Please provide all the data, such as when the coupon payments for each bond occur and the associated amount that was used to calculate the expense lead time of 15.16 days for interest on long-term debt.

b) A number of debt issuances have or will mature between 2010 and the test years of 2013 and 2014. Please provide the calculation of the expense lead time for each of 2013 and 2014 based on the debt instruments shown in Interrogatory #18-LPMA-31 that requested an update to the 2013 and 2014 schedules shown in Exhibit B2, Tab 1, Schedule 2.

Response

a) Please see the table below:

INTEREST EXPENSE - TX

TX Portion	Interest Rate	Payment Amt	Period Beginning	Period Ending	Payment Date	Service Lead Time Days	Payment Lead Time Days	Total Lead Time Days	Weighting Factor	Weighted Lead Time
330.00	5.490%	$ 9.06	1/1/2010	12/31/2010	1/16/2010	182.50	(349.00)	(166.50)	3.87%	(6.45)
237.00	6.350%	$ 7.52	1/1/2010	12/31/2010	1/31/2010	182.50	(334.00)	(151.50)	3.22%	(4.87)
150.00	1.493%	$ 1.12	1/1/2010	12/31/2010	3/3/2010	182.50	(303.00)	(120.50)	0.48%	(0.58)
270.00	4.640%	$ 6.26	1/1/2010	12/31/2010	3/3/2010	182.50	(303.00)	(120.50)	2.68%	(3.23)
195.00	6.030%	$ 5.88	1/1/2010	12/31/2010	3/3/2010	182.50	(303.00)	(120.50)	2.51%	(3.03)
150.00	2.950%	$ 2.21	1/1/2010	12/31/2010	3/11/2010	182.50	(295.00)	(112.50)	0.95%	(1.06)
240.00	4.890%	$ 5.87	1/1/2010	12/31/2010	3/13/2010	182.50	(293.00)	(110.50)	2.51%	(2.77)
405.00	5.180%	$ 10.49	1/1/2010	12/31/2010	4/18/2010	182.50	(257.00)	(74.50)	4.49%	(3.34)
180.00	5.000%	$ 4.50	1/1/2010	12/31/2010	4/19/2010	182.50	(256.00)	(73.50)	1.92%	(1.41)
184.00	6.590%	$ 6.06	1/1/2010	12/31/2010	4/22/2010	182.50	(253.00)	(70.50)	2.59%	(1.83)
370.00	5.000%	$ 9.25	1/1/2010	12/31/2010	5/12/2010	182.50	(233.00)	(50.50)	3.96%	(2.00)
276.00	5.770%	$ 7.96	1/1/2010	12/31/2010	5/15/2010	182.50	(230.00)	(47.50)	3.40%	(1.62)
175.00	3.130%	$ 2.74	1/1/2010	12/31/2010	5/19/2010	182.50	(226.00)	(43.50)	1.17%	(0.51)
150.00	1.716%	$ 1.29	1/1/2010	12/31/2010	5/19/2010	182.50	(226.00)	(43.50)	0.55%	(0.24)
416.40	5.360%	$ 11.16	1/1/2010	12/31/2010	5/20/2010	182.50	(225.00)	(42.50)	4.77%	(2.03)
174.00	6.400%	$ 5.57	1/1/2010	12/31/2010	6/1/2010	182.50	(213.00)	(30.50)	2.38%	(0.73)
180.00	4.400%	$ 3.96	1/1/2010	12/31/2010	6/1/2010	182.50	(213.00)	(30.50)	1.69%	(0.52)
167.27	6.930%	$ 5.80	1/1/2010	12/31/2010	6/1/2010	182.50	(213.00)	(30.50)	2.48%	(0.76)
278.40	7.350%	$ 10.23	1/1/2010	12/31/2010	6/3/2010	182.50	(211.00)	(28.50)	4.37%	(1.25)
330.00	5.490%	$ 9.06	1/1/2010	12/31/2010	7/16/2010	182.50	(168.00)	14.50	3.87%	0.56
237.00	6.350%	$ 7.52	1/1/2010	12/31/2010	7/31/2010	182.50	(153.00)	29.50	3.22%	0.95
150.00	1.493%	$ 1.12	1/1/2010	12/31/2010	9/3/2010	182.50	(119.00)	63.50	0.48%	0.30
270.00	4.640%	$ 6.26	1/1/2010	12/31/2010	9/3/2010	182.50	(119.00)	63.50	2.68%	1.70
195.00	6.030%	$ 5.88	1/1/2010	12/31/2010	9/3/2010	182.50	(119.00)	63.50	2.51%	1.60
150.00	2.950%	$ 2.21	1/1/2010	12/31/2010	9/11/2010	182.50	(111.00)	71.50	0.95%	0.68
240.00	4.890%	$ 5.87	1/1/2010	12/31/2010	9/13/2010	182.50	(109.00)	73.50	2.51%	1.84
405.00	5.180%	$ 10.49	1/1/2010	12/31/2010	10/18/2010	182.50	(74.00)	108.50	4.49%	4.87
180.00	5.000%	$ 4.50	1/1/2010	12/31/2010	10/19/2010	182.50	(73.00)	109.50	1.92%	2.11
184.00	6.590%	$ 6.06	1/1/2010	12/31/2010	10/22/2010	182.50	(70.00)	112.50	2.59%	2.92
370.00	5.000%	$ 9.25	1/1/2010	12/31/2010	11/12/2010	182.50	(49.00)	133.50	3.96%	5.28
276.00	5.770%	$ 7.96	1/1/2010	12/31/2010	11/15/2010	182.50	(46.00)	136.50	3.40%	4.65
175.00	3.130%	$ 2.74	1/1/2010	12/31/2010	11/19/2010	182.50	(42.00)	140.50	1.17%	1.65
150.00	1.716%	$ 1.29	1/1/2010	12/31/2010	11/19/2010	182.50	(42.00)	140.50	0.55%	0.77
416.40	5.360%	$ 11.16	1/1/2010	12/31/2010	11/20/2010	182.50	(41.00)	141.50	4.77%	6.75
174.00	6.400%	$ 5.57	1/1/2010	12/31/2010	12/1/2010	182.50	(30.00)	152.50	2.38%	3.63
180.00	4.400%	$ 3.96	1/1/2010	12/31/2010	12/1/2010	182.50	(30.00)	152.50	1.69%	2.58
167.27	6.930%	$ 5.80	1/1/2010	12/31/2010	12/1/2010	182.50	(30.00)	152.50	2.48%	3.78
278.40	7.350%	$ 10.23	1/1/2010	12/31/2010	12/3/2010	182.50	(28.00)	154.50	4.37%	6.76
$ 4,528.07		$ 233.86								15.16

b) Based on the debt instruments shown in Exhibit I, Tab 18, Schedule 2.03 LPMA31, the interest expense lead days are 6.35 for 2013 and 4.98 for 2014.

2013 - INTEREST EXPENSE - TX

TX Portion	Interest Rate	Period Beginning	Period Ending	First Payment Date	Second Payment Date	First Payment Amount $M	Second Payment Amount $M	First Payment			Second Payment			Weighting Factor First Payment	Weighting Factor Second Payment	Weighted Lead Time Days
								Service Lead Time Days	Payment Lead Time Days	Total Lead Time Days	Service Lead Time Days	Payment Lead Time Days	Total Lead Time Days			
(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)	(O)	(P)	(Q)	(R)
370.00	5.000%	1/1/2013	12/31/2013	5/12/2013	11/12/2013	9.25	9.25	182.50	(233.00)	(50.50)	182.50	(49.00)	133.50	3.41%	3.41%	2.83
175.00	3.130%	1/1/2013	12/31/2013	5/19/2013	11/19/2013	2.73875	2.73875	182.50	(226.00)	(43.50)	182.50	(42.00)	140.50	1.01%	1.01%	0.98
150.00	2.950%	1/1/2013	12/31/2013	3/11/2013	9/11/2013	2.2125	2.2125	182.50	(295.00)	(112.50)	182.50	(111.00)	71.50	0.82%	0.82%	(0.33)
270.00	4.640%	1/1/2013	12/31/2013	3/3/2013	9/3/2013	6.264	6.264	182.50	(303.00)	(120.50)	182.50	(119.00)	63.50	2.31%	2.31%	(1.32)
405.00	5.180%	1/1/2013	12/31/2013	4/17/2013	10/17/2013	10.4895	10.4895	182.50	(258.00)	(75.50)	182.50	(75.00)	107.50	3.86%	3.86%	1.24
258.38	2.181%	1/1/2013	12/31/2013	3/16/2013	9/16/2013	2.817531	2.817531	182.50	(290.00)	(107.50)	182.50	(106.00)	76.50	1.04%	1.04%	(0.32)
150.00	2.431%	1/1/2013	12/31/2013	3/15/2013	9/15/2013	1.823196	1.823196	182.50	(291.00)	(108.50)	182.50	(107.00)	75.50	0.67%	0.67%	(0.22)
180.00	4.400%	1/1/2013	12/31/2013	6/4/2013	12/4/2013	3.96	3.96	182.50	(210.00)	(27.50)	182.50	(27.00)	155.50	1.46%	1.46%	1.87
319.00	3.200%	1/1/2013	12/31/2013	1/13/2013	7/13/2013	5.104	5.104	182.50	(352.00)	(169.50)	182.50	(171.00)	11.50	1.88%	1.88%	(2.97)
388.38	3.152%	1/1/2013	12/31/2013	6/15/2013	12/15/2013	6.120834	6.120834	182.50	(199.00)	(16.50)	182.50	(16.00)	166.50	2.26%	2.26%	3.38
278.40	7.350%	1/1/2013	12/31/2013	6/3/2013	12/3/2013	10.2312	10.2312	182.50	(211.00)	(28.50)	182.50	(28.00)	154.50	3.77%	3.77%	4.75
167.27	6.930%	1/1/2013	12/31/2013	6/1/2013	12/1/2013	5.795975	5.795975	182.50	(213.00)	(30.50)	182.50	(30.00)	152.50	2.14%	2.14%	2.61
237.00	6.350%	1/1/2013	12/31/2013	1/31/2013	7/31/2013	7.52475	7.52475	182.50	(334.00)	(151.50)	182.50	(153.00)	29.50	2.77%	2.77%	(3.38)
416.40	5.360%	1/1/2013	12/31/2013	5/20/2013	11/20/2013	11.15952	11.15952	182.50	(225.00)	(42.50)	182.50	(41.00)	141.50	4.11%	4.11%	4.07
240.00	4.890%	1/1/2013	12/31/2013	3/13/2013	9/13/2013	5.868	5.868	182.50	(293.00)	(110.50)	182.50	(109.00)	73.50	2.16%	2.16%	(0.80)
195.00	6.030%	1/1/2013	12/31/2013	3/3/2013	9/3/2013	5.87925	5.87925	182.50	(303.00)	(120.50)	182.50	(119.00)	63.50	2.17%	2.17%	(1.23)
210.00	5.490%	1/1/2013	12/31/2013	1/13/2013	7/13/2013	5.7645	5.7645	182.50	(352.00)	(169.50)	182.50	(171.00)	11.50	2.12%	2.12%	(3.36)
120.00	5.490%	1/1/2013	12/31/2013	1/21/2013	7/21/2013	3.294	3.294	182.50	(344.00)	(161.50)	182.50	(163.00)	19.50	1.21%	1.21%	(1.72)
205.00	4.390%	1/1/2013	12/31/2013	3/26/2013	9/26/2013	4.49975	4.49975	182.50	(280.00)	(97.50)	182.50	(96.00)	86.50	1.66%	1.66%	(0.18)
388.38	4.068%	1/1/2013	12/31/2013	3/15/2013	9/15/2013	7.898788	7.898788	182.50	(291.00)	(108.50)	182.50	(107.00)	75.50	2.91%	2.91%	(0.96)
184.00	6.590%	1/1/2013	12/31/2013	4/22/2013	10/22/2013	6.0628	6.0628	182.50	(253.00)	(70.50)	182.50	(70.00)	112.50	2.23%	2.23%	0.94
180.00	5.000%	1/1/2013	12/31/2013	4/18/2013	10/18/2013	4.5	4.5	182.50	(257.00)	(74.50)	182.50	(74.00)	108.50	1.66%	1.66%	0.56
138.75	4.000%	1/1/2013	12/31/2013	6/21/2013	12/21/2013	2.775	2.775	182.50	(193.00)	(10.50)	182.50	(10.00)	172.50	1.02%	1.02%	1.66
193.50	3.790%	1/1/2013	12/31/2013	1/28/2013	7/28/2013	3.666825	3.666825	182.50	(337.00)	(154.50)	182.50	(156.00)	26.50	1.35%	1.35%	(1.73)
						135.7007	135.7007									**6.35**

2014 - INTEREST EXPENSE - TX

TX Portion	Interest Rate	Period Beginning	Period Ending	First Payment Date	Second Payment Date	First Payment Amount $M	Second Payment Amount $M	First Payment			Second Payment			Weighting Factor First Payment	Weighting Factor Second Payment	Weighted Lead Time Days
								Service Lead Time Days	Payment Lead Time Days	Total Lead Time Days	Service Lead Time Days	Payment Lead Time Days	Total Lead Time Days			
(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)	(O)	(P)	(Q)	(R)
175.00	3.130%	1/1/2014	12/31/2014	5/19/2014	11/19/2014	2.73875	2.73875	182.50	(226.00)	(43.50)	182.50	(42.00)	140.50	0.93%	0.93%	0.90
150.00	2.950%	1/1/2014	12/31/2014	3/11/2014	9/11/2014	2.2125	2.2125	182.50	(295.00)	(112.50)	182.50	(111.00)	71.50	0.75%	0.75%	(0.31)
270.00	4.640%	1/1/2014	12/31/2014	3/3/2014	9/3/2014	6.264	6.264	182.50	(303.00)	(120.50)	182.50	(119.00)	63.50	2.13%	2.13%	(1.21)
405.00	5.180%	1/1/2014	12/31/2014	4/17/2014	10/17/2014	10.4895	10.4895	182.50	(258.00)	(75.50)	182.50	(75.00)	107.50	3.56%	3.56%	1.14
258.38	2.181%	1/1/2014	12/31/2014	3/16/2014	9/16/2014	2.817531	2.817531	182.50	(290.00)	(107.50)	182.50	(106.00)	76.50	0.96%	0.96%	(0.30)
150.00	2.431%	1/1/2014	12/31/2014	3/15/2014	9/15/2014	1.823196	1.823196	182.50	(291.00)	(108.50)	182.50	(107.00)	75.50	0.62%	0.62%	(0.20)
289.85	3.981%	1/1/2014	12/31/2014	3/15/2014	9/15/2014	5.769265	5.769265	182.50	(291.00)	(108.50)	182.50	(107.00)	75.50	1.96%	1.96%	(0.65)
180.00	4.400%	1/1/2014	12/31/2014	6/4/2014	12/4/2014	3.96	3.96	182.50	(210.00)	(27.50)	182.50	(27.00)	155.50	1.35%	1.35%	1.72
319.00	3.200%	1/1/2014	12/31/2014	1/13/2014	7/13/2014	5.104	5.104	182.50	(352.00)	(169.50)	182.50	(171.00)	11.50	1.73%	1.73%	(2.74)
388.38	3.152%	1/1/2014	12/31/2014	6/15/2014	12/15/2014	6.120834	6.120834	182.50	(199.00)	(16.50)	182.50	(16.00)	166.50	2.08%	2.08%	3.12
289.85	4.702%	1/1/2014	12/31/2014	6/15/2014	12/15/2014	6.814194	6.814194	182.50	(199.00)	(16.50)	182.50	(16.00)	166.50	2.31%	2.31%	3.47
278.40	7.350%	1/1/2014	12/31/2014	6/3/2014	12/3/2014	10.2312	10.2312	182.50	(211.00)	(28.50)	182.50	(28.00)	154.50	3.48%	3.48%	4.38
167.27	6.930%	1/1/2014	12/31/2014	6/1/2014	12/1/2014	5.795975	5.795975	182.50	(213.00)	(30.50)	182.50	(30.00)	152.50	1.97%	1.97%	2.40
237.00	6.350%	1/1/2014	12/31/2014	1/31/2014	7/31/2014	7.52475	7.52475	182.50	(334.00)	(151.50)	182.50	(153.00)	29.50	2.56%	2.56%	(3.12)
416.40	5.360%	1/1/2014	12/31/2014	5/20/2014	11/20/2014	11.15952	11.15952	182.50	(225.00)	(42.50)	182.50	(41.00)	141.50	3.79%	3.79%	3.75
240.00	4.890%	1/1/2014	12/31/2014	3/13/2014	9/13/2014	5.868	5.868	182.50	(293.00)	(110.50)	182.50	(109.00)	73.50	1.99%	1.99%	(0.74)
195.00	6.030%	1/1/2014	12/31/2014	3/3/2014	9/3/2014	5.87925	5.87925	182.50	(303.00)	(120.50)	182.50	(119.00)	63.50	2.00%	2.00%	(1.14)
330.00	5.490%	1/1/2014	12/31/2014	1/13/2014	7/13/2014	9.0585	9.0585	182.50	(352.00)	(169.50)	182.50	(171.00)	11.50	3.08%	3.08%	(4.86)
205.00	4.390%	1/1/2014	12/31/2014	3/26/2014	9/26/2014	4.49975	4.49975	182.50	(280.00)	(97.50)	182.50	(96.00)	86.50	1.53%	1.53%	(0.17)
388.38	4.068%	1/1/2014	12/31/2014	3/15/2014	9/15/2014	7.898788	7.898788	182.50	(291.00)	(108.50)	182.50	(107.00)	75.50	2.68%	2.68%	(0.89)
184.00	6.590%	1/1/2014	12/31/2014	4/22/2014	10/22/2014	6.0628	6.0628	182.50	(253.00)	(70.50)	182.50	(70.00)	112.50	2.06%	2.06%	0.87
289.85	5.618%	1/1/2014	12/31/2014	3/15/2014	9/15/2014	8.141057	8.141057	182.50	(291.00)	(108.50)	182.50	(107.00)	75.50	2.77%	2.77%	(0.91)
180.00	5.000%	1/1/2014	12/31/2014	4/18/2014	10/18/2014	4.5	4.5	182.50	(257.00)	(74.50)	182.50	(74.00)	108.50	1.53%	1.53%	0.52
138.75	4.000%	1/1/2014	12/31/2014	6/21/2014	12/21/2014	2.775	2.775	182.50	(193.00)	(10.50)	182.50	(10.00)	172.50	0.94%	0.94%	1.53
193.50	3.790%	1/1/2014	12/31/2014	1/28/2014	7/28/2014	3.666825	3.666825	182.50	(337.00)	(154.50)	182.50	(156.00)	26.50	1.25%	1.25%	(1.59)
						147.1752	147.1752									**4.98**

Energy Probe (EP) INTERROGATORY #56 List 1

Issue 15 **Are the inputs used to determine the working capital component of the rate base and the methodology used appropriate?**

Interrogatory

Ref: Exhibit D1, Tab1, Schedule 1, Table 1 and Attachment 1 (Navigant)

a) Please provide the equivalent version of Table 1 with 2011 and 2012 WCA amounts and rates as approved by the Board.

b) Identify and discuss the drivers of the changes for 2013/2014 (Table 7 Navigant) and indicate if these changes are expected to continue into the future.

c) Estimate the impact these would have made to 2011 and 2012 WCA and net cash requirement.

Response

a)

	Revenue Lag (Days)	Expense Lag (Days)	Net Lag (Lead) (Days)	2011 OEB Approved Amount	2012 OEB Approved Amount
	(A)	(B)	(C)	(D)	(E)
Expenses					
OM&A Expenses	36.40	21.73	14.67	436.3	450.0
Removal costs	36.40	30.02	6.38	18.4	18.1
Environmental Remediation	36.40	34.84	1.56	7.3	7.8
Interest on Long term debt	36.40	52.87	(16.47)	260.6	291.7
Income tax	36.40	16.51	19.89	80.9	70.0
Total				**803.5**	**837.5**
GST (see Table 2)				23.2	27.9
TOTAL AMOUNTS PAID/ACCRUED				**826.8**	**865.4**
Working Capital Required (Calculations based on above values, for each expense category, calculated using the following formula: For 2011 Col (D)*Col (C)/365 For 2012 Col (E)*Col (C)/366)					
OM&A Expenses				17.5	18.0
Removal costs				0.3	0.3
Environmental Remediation				0.0	0.0
Interest on Long term debt				(11.8)	(13.1)
Income tax				4.4	3.8
Total				**10.5**	**9.1**
GST (see Table 2)				(3.5)	(4.1)
NET WORKING CASH REQUIRED				**7.1**	**5.0**

b) The impacts affecting the 2013/2014 lead/lag days are discussed on page 14 through 15 as well as in the Conclusion of the Navigant report.

c) If the previous study is restated using the lead / lag days in the current study, the estimated WCA percentages would be 2.31% for 2011 and 2.49% for 2012.

Ontario Energy Board (Board Staff) INTERROGATORY #73 List 1

Issue 16 **Does Hydro One's Asset Condition Assessment information and Investment Planning Process adequately address the condition of the transmission system assets and support the O&MA and Capital expenditures for 2013/14?**

Interrogatory

Ref: Exhibit 10 Year Asset Management Outlook 2012 to 2021, p.25, Fig. 4.3 a, 4.3 b and 4.3 c

a) Please provide the average of the CEA Composite Index and Hydro One's actual average number of momentary interruptions per Delivery Point, for the period 2002 – 2011both of which are represented in Fig 4.3 a.

b) Please provide the average of the CEA Composite Index and the Hydro One's actual average number of forced sustained interruptions per Delivery Point, for the period 2002 – 2011both of which are represented in Fig 4.3 b.

c) Please provide the average of the CEA Composite Index and the Hydro One's actual average minutes of interruptions per Delivery Point, for the period 2002 – 2011both of which are represented in Fig 4.3 c.

Response

Re: Exhibit A, Tab 13, Schedule 2, Pg. 25, 10 Year Asset Management Outlook 2012 to 2021

a) The 2011 CEA composite values will not be published until late 2012. The following Table 1 provides the averages for the period from 2002 to 2010 for the CEA Composite Index and Hydro One's actual. Also provided is the Hydro One average from 2002 to 2011 as requested.

b) Please see the second row of Table 1 for the values requested:

Table 1: Average CEA Composite Index and Hydro One's Actual

	Period		
	2002 to 2010		2002 to 2011
Figure Reference	CEA Composite	Hydro One	Hydro One
Fig. 4.3a: Frequency of Delivery Point Interruptions (Momentary)	0.84	0.70	0.69
Fig. 4.3b: Frequency of Delivery Point Interruptions (Forced Sustained)	0.79	0.67	0.66
Fig. 4.4: Duration of Delivery Point Interruptions (Forced Sustained) (includes 2011 forest fire)	90.8	52.0	59.6
Fig. 4.4: Duration of Delivery Point Interruptions (Forced Sustained) (excludes 2011 forest fire)	90.8	52.0	52.7

c) The referenced Fig. 4.3c is assumed to be Fig. 4.4 Duration of Delivery Point Interruptions (Forced Sustained) on page 25. Please see the third and fourth rows of Table 1 for the values requested.

Ontario Energy Board (Board Staff) INTERROGATORY #74 List 1

Issue 16 **Does Hydro One's Asset Condition Assessment information and Investment Planning Process adequately address the condition of the transmission system assets and support the O&MA and Capital expenditures for 2013/14?**

Interrogatory

Ref: Exhibit 10 Year Asset Management Outlook 2012 to 2021, p. 36 – Power Transformer Portfolio

a) Fig. 5.2 (a) provides the Power Transformer Demographics of Hydro One's population of transformers. Please provide the transformer demographics for power transformers in the CEA's multi-utility database.

b) Fig. 5.2 (b) provides the Power Transformer Condition of Hydro One's population of transformers.

  i. Please provide the transformer demographics for power transformers in the CEA's multi-utility database.

  ii. What is the average age of transformers in the three asset condition categories in Fig. 5.2(b)?

c) At page 37 of the above reference, Hydro One has provided various equipment replacement scenarios based on number of units replaced per year. In Hydro One's view what is an appropriate replacement rate for its population of transformers?

Response

a) CEA multi-utility database does not contain transformer demographics.

b)

  i. CEA multi-utility database does not contain transformer demographics or condition information.

  ii. The average age of transformers in the "Good" asset condition category is about 30 years. The average age of transformers in the "Fair" asset condition category is about 55 years. The average age of transformers in the "Poor" asset condition category is about 49 years.

c) The replacement scenarios presented on pg 37 of the 10 Year Transmission Asset Management Outlook, ("Outlook") are based on demographics information only. Hydro One views the information in Figure 5.2g pg 37 in the Outlook to be illustrative for providing indications of the change in demographics of the transformer asset group, assuming a range of equipment replacements. As noted in the last sentence on page 37 of the Outlook, additional factors are needed to provide a more definitive answer. For the test years, the equipment replacements are noted in Exhibit D1, Tab 3, Schedule 2 under Power Transformers (page 20) and some projects within System Re-investment (ISD#s S15, S16, S18, S19). Clarification is also provided in Exhibit I, Tab 12, Schedule 1.15 Staff 68.

<u>Ontario Energy Board (Board Staff) INTERROGATORY #75 List 1</u>

Issue 16 **Does Hydro One's Asset Condition Assessment information and Investment Planning Process adequately address the condition of the transmission system assets and support the O&MA and Capital expenditures for 2013/14?**

Interrogatory

Ref: Exhibit 10 Year Asset Management Outlook 2012 to 2021, p. 40 – Overhead Conductor Portfolio

a) Fig 5.4 (b) provides the Asset Condition Assessment of the overhead conductors.

   i. Please provide the average age of conductors in each of the three asset condition categories?

   ii. Based on fig 5.4 (b), approximately 50% of conductors are in "good" condition, 34% are in "fair" condition and 16% are in poor condition. In Hydro One's view, what is a reasonable/sustainable ratio for the three categories of asset conditions?

   iii. Please provide the asset demographics of overhead conductors in the CEA's multi-utility database.

b) With respect to the Historical Equipment Replacement in fig. 5.4 (e), please explain the large drop in conductor replacement in 2008.

c) At page 41 of the above reference, Hydro One has provided various equipment replacement scenarios based on number of kilometers of conductors replaced per year. In Hydro One's view what is an appropriate replacement rate for its population of overhead conductors?

Response

a)

   i. The average age of conductors in the "Good" asset condition category is about 33 years. The average age of conductors in the "Fair" asset condition category is about 60 years. The average age of conductors in the "Poor" asset condition category is about 81 years.

   ii. In Hydro One's view, sustainment of current condition ratios would contribute to maintaining present reliability levels. However, other factors and considerations are taken into account to determine the investment plan (refer to response to part c) of this question.

iii. The CEA multi-utility database does not contain asset demographics of overhead conductors.

b) Due to project specific real estate and easement complications, one of the line refurbishment projects originally planned for completion in 2008 was delayed, impacting accomplishments in that year.

c) The replacement scenarios presented on page 41 of the 10 Year Transmission Asset Management Outlook are based on demographics information only and are illustrative for providing indications of the change in demographics of overhead conductors assuming a variety of replacement rates. As noted in the last sentence on page 41, additional factors are needed to provide a more definitive answer.

For the 2012-2014 years, the annual replacements are noted in the table at the bottom of page 72 of Exhibit C1, Tab 2, Schedule 2 as 22km, 75km, and 95km respectively. Hydro One views these annual replacements as appropriate for the referenced years. It is foreseeable that future replacement rates will need to increase to maintain existing condition and reliability levels.

Ontario Energy Board (Board Staff) INTERROGATORY #76 List 1

Issue 16 **Does Hydro One's Asset Condition Assessment information and Investment Planning Process adequately address the condition of the transmission system assets and support the O&MA and Capital expenditures for 2013/14?**

Interrogatory

Ref: Exhibit 10 Year Asset Management Outlook 2012 to 2021, p. 46 – Wood Pole Portfolio

a) Fig. 5.7 (b) provides the Asset Condition Assessment of wood poles. Please provide the average age of poles in each of the three asset condition categories.

b) Hydro One's historical replacement rate has averaged 710 poles/year, and has increased slightly over the years. In Hydro One's view what is an appropriate replacement rate for its wood pole portfolio?

Response

The average age of poles in the "Good" asset condition category is about 30 years. The average age of poles in the "Fair" asset condition category is about 33 years. The average age of poles in the "Poor" asset condition category is about 36 years.

a) The replacement scenarios presented on page 47 of the 10 Year Transmission Asset Management Outlook are based on demographics information only and are illustrative for providing indications of the change in demographics. As noted in the last sentence in page 47, additional factors are needed to provide a more definitive answer.

b) As outlined in Exhibit C1, Tab 2, Schedule 2, page 53, over the 5-year period of 2007–2011 the annual replacements averaged 829 poles, whereas the 710 poles / year is a 10-year average. Hydro One views the proposed accomplishment of 850 replacements per year as appropriate for its wood pole population over the 2012-14 period.

London Property Management Association (LPMA) INTERROGATORY #28 List 1

Issue 17 Is the proposed timing and methodology for determining the return on equity and short-term debt prior to the effective date of rates appropriate?

Interrogatory

Ref: Exhibit B1, Tab 1, Schedule 1

a) What is the impact on the 2013 and 2014 revenue requirements of a 10 basis point change in the return on equity?

b) What is the impact on the 2013 and 2014 revenue requirements of a 10 basis point change in the short-term debt rate?

c) What would be the impact on the 2014 revenue requirement if the Board determined that the return on equity should be kept at the 2013 rate of 9.16% rather than the 9.44% forecast by Hydro One for 2014?

d) What would be the impact on the 2014 revenue requirement if the Board determined that the short-term debt rate should be kept at the 2013 rate of 2.01% rather than the 2.98% forecast by Hydro One for 2014?

Response

a) The impact on the 2013 revenue requirement of a 10 basis point decrease in the return on equity is a $5.12M reduction. The impact on the 2014 revenue requirement of a 10 basis point decrease in the return on equity is a $5.48M reduction.

b) The impact on the 2013 revenue requirement of a 10 basis point decrease in the short-term debt rate is a $0.38M reduction. The impact on the 2014 revenue requirement of a 10 basis point decrease in the short-term debt rate is a $0.40M reduction.

c) The impact on the 2014 revenue requirement if the Board determined that the return on equity should be kept at the 2013 rate of 9.16% rather than the 9.44% forecast by Hydro One is a $15.33M reduction.

d) The impact on the 2014 revenue requirement if the Board determined that the short-term debt rate should be kept at the 2013 rate of 2.01% rather than the 2.98% forecast by Hydro One is a $3.90M reduction.

Energy Probe (EP) INTERROGATORY #57 List 1

Issue 17 **Is the proposed timing and methodology for determining the return on equity and short-term debt prior to the effective date of rates appropriate?**

Interrogatory

Ref: Exhibit B1, Tab 1, Schedule 1, Pages 1&2
Exhibit B2, Tab 1, Schedule 1, Page 2

For 2014, the return on equity calculation is based on the February 2012 Global Insight Forecast, as well as Bank of Canada data and the change in the spread of A-rated Utility Bond Yields during February. Hydro One assumes that the return on equity for each test year will be updated in accordance with the December 11, 2009 Cost of Capital Report.

a) For 2014, explain why the ROE placeholder should not be the same as 2013 rather than the Global Insight forecast.

b) Please provide a schedule that shows the 2014 cost of capital using the 2013 ROE forecast.

Response

a) Hydro One tries to provide the Board a forecast with the most up-to-date interest rate information available, therefore the 2014 long-term debt rate forecasted by Global Insight in February was used to estimate the ROE and cost of debt. However, Hydro One will update the cost of capital parameters consistent with the cost of capital information the Board will issue in November 2013 for rates effective January 2014.

b) Attached is a 2014 cost of capital schedule using the 2013 ROE forecast.

2014 Cost of Capital

	2014			
Amount of Deemed	**($M)**	**%**	**Cost Rate (%)**	**Return ($M)**
Long-term debt	5,628.5	56.0%	4.83%	271.8
Short-term debt	402.0	4.0%	2.98%	12.0
Common equity	4,020.4	40.0%	9.16%	368.2
Total	10,050.9	100.0%	6.49%	652.0

Consumers Council of Canada (CCC) INTERROGATORY #36 List 1

Issue 17 Is the proposed timing and methodology for determining the return on equity and short-term debt prior to the effective date of rates appropriate

Interrogatory

(Ex. B) Please provide the actual ROE for HONI for the years 2008-2011. Please provide the calculated ROE for Transmission and Distribution in each of those years.

Response

	2008	2009	2010	2011
Hydro One Networks Inc. ROE (1)	10.8%	9.4%	11.1%	11.0%
Transmission ROE Proxy (2)	12.0%	9.0%	10.9%	10.3%
Distribution ROE Proxy (2)	7.4%	9.4%	10.3%	11.4%

Note 1: Hydro One Networks Inc. ROE is calculated from financial statements prepared under Canadian GAAP.

Note 2: Hydro One Networks' Transmission and Distribution businesses have no separate legal status or existence and therefore do not have share capital. A proxy for ROE was derived by taking the net income divided by the excess of assets over liabilities per the audited financial statements.

Association of Major Power Consumers in Ontario (AMPCO) INTERROGATORY #11 List 1

Issue 17 Is the proposed timing and methodology for determining the return on equity and short-term debt prior to the effective date of rates appropriate?

Interrogatory

a) Please complete the following table for Hydro One Transmission:

Year	Board Approved Revenue	Actual Revenue	Board approved ROE	Actual ROE
2008				
2009				
2010				
2011				

Response

Year	Board Approved Revenue ($M)	Actual Revenue[1] ($M)	Board Approved ROE	Actual ROE[2]
2008	1,170	1,211	8.35%	12.00%
2009	1,179	1,147	8.01%	9.00%
2010	1,257	1,307	8.39%	10.90%
2011	1,346	1,390	9.66%	10.30%

Note 1: The actual revenue amounts in the table above are obtained from the filed audited financial statements prepared for accounting purposes and are not weather-normalized; whereas, the Board-approved revenue amounts are weather normalized and derived for the purpose of calculating the regulatory revenue requirement.

Note 2: Hydro One Networks' Transmission business has no separate legal status or existence and therefore do not have share capital. A proxy for ROE was derived by taking the net income divided by the excess of assets over liabilities per the audited financial statements.

London Property Management Association (LPMA) INTERROGATORY #29 List 1

Issue 18 Is the forecast of long term debt for 2012-2014 appropriate?

Interrogatory

Ref: Exhibit B1, Tab 2, Schedule 1

a) Please update Table 4 to reflect the most recent forecasts available.

b) Please confirm that the treasury OM&A costs are included in the cost of debt, and not in OM&A.

c) Please confirm that the treasury OM&A costs of $1.6 million for 2013 and $1.7 million for 2014 are the transmission share of the total treasury OM&A costs only. If confirmed, please explain how the transmission share is determined on an annual basis.

Response

a)

Table 4
Forecast Yield for 2012-2014 Issuance Terms

	2012		
	5-year	**10-year**	**30-year**
Government of Canada	1.37%	1.80%	2.35%
Hydro One Spread	0.81%	1.10%	1.47%
Forecast Hydro One Yield	2.18%	2.90%	3.82%
	2013		
	5-year	**10-year**	**30-year**
Government of Canada	1.62%	2.05%	2.60%
Hydro One Spread	0.81%	1.10%	1.47%
Forecast Hydro One Yield	2.43%	3.15%	4.07%

	2014		
	5-year	**10-year**	**30-year**
Government of Canada	3.17%	3.60%	4.15%
Hydro One Spread	0.81%	1.10%	1.47%
Forecast Hydro One Yield	3.98%	4.70%	5.62%

b) Treasury OM&A costs are included in the cost of debt, and not in OM&A, as discussed on page 6 and 7 of Exhibit B1, Tab 2, Schedule 1.

c) The treasury OM&A costs of $1.6 million for 2013 and $1.7 million for 2014 are only the transmission share of the total treasury OM&A costs. The transmission share of the costs is determined on an annual basis, based on the Transmission Business' proportionate share of Hydro One Network's total debt outstanding.

London Property Management Association (LPMA) INTERROGATORY #30 List 1

Issue 18 Is the forecast of long term debt for 2012-2014 appropriate?

Interrogatory

Ref: Exhibit B2, Tab 1, Schedule 1

a) Please explain why Hydro One shows no preference shares in 2013 or 2014 despite having $239 million in preference shares in 2009 through 2012.

b) What is the forecasted rate for 2013 and 2014 associated with the preference shares?

c) If the Board determined that the preference shares should be used in the calculation of the cost of capital, what other components of the capital structure would Hydro One propose to be adjusted?

Response

a) Preference shares are shown in 2009 through 2012 in Exhibit B2, Tab 1, Schedule 1 based on the actual capital structure for historic years and the projected capital structure for the bridge year. Hydro One uses the deemed capital structure of 60% debt and 40% common equity for rate making purposed for the test years 2013 and 2014. This capital structure was approved by the Board as part of its December 23, 2010 Decision on Hydro One's Transmission Rate Application (EB-2010-0002) and is also consistent with the Board's December 11, 2009 Report on the Cost of Capital for Ontario's Regulated Utilities (EB-2009-0084) ("the Cost of Capital Report").

b) The Board's cost of capital parameters do not include a rate for preference shares.

c) Hydro One would apply the approved cost of capital structure on its rate base in a manner consistent with the Board's guidelines.

London Property Management Association (LPMA) INTERROGATORY #31 List 1

Issue 18 Is the forecast of long term debt for 2012-2014 appropriate?

Interrogatory

Ref: Exhibit B2, Tab 1, Schedule 2

a) Please explain the increase in Treasury OM&A costs in 2012 to $1.6 million given these costs were maintained at $1.2 million in 2009 through 2011.

b) Please update the bridge year table (page 4) to reflect actual debt issues in 2012, along with the most recent forecasts of the amount and rate associated with debt issues to be completed in 2012.

c) Please update the test year schedules (pages 5 and 6) to reflect the response to part (b), along with the most recent forecast of rates available.

Response

a) The increase in Treasury OM&A costs in 2012 are attributable to the upgrading of Treasury's back office systems as well as increased resource requirements to maintain broad based access to debt markets. Treasury's back office systems are used for daily cash flow forecasting, transaction recording, tracking payment of interest and principal, monitoring counterparty credit risk, and accounting journal entries and reporting. Hydro One's debt is forecast to increase over the next 3 years as rate base grows. In order to ensure continued access to capital markets Hydro One feels it would be prudent to increase its efforts to maintain relationships with existing investors and reach out to new potential investors going forward.

b) Please see Attachment 1.

c) Please see Attachment 2.

HYDRO ONE NETWORKS INC.
TRANSMISSION
Cost of Long-Term Debt Capital
Bridge Year (2012)
Year ending December 31

b)

Line No.	Offering Date	Coupon Rate	Maturity Date	Principal Amount Offered ($Millions)	Premium Discount and Expenses ($Millions)	Net Capital Employed: Total Amount ($Millions)	Net Capital Employed: Per $100 Principal Amount (Dollars)	Effective Cost Rate	Total Amount Outstanding: at 12/31/11 ($Millions)	Total Amount Outstanding: at 12/31/12 ($Millions)	Avg. Monthly Averages ($Millions)	Carrying Cost ($Millions)	Projected Average Embedded Cost Rates
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
1	3-Jun-00	7.350%	3-Jun-30	278.4	4.5	273.9	98.37	7.49%	278.4	278.4	278.4	20.8	
2	22-Jun-01	6.930%	1-Jun-32	109.3	1.0	108.2	99.05	7.01%	109.3	109.3	109.3	7.7	
3	17-Sep-02	5.770%	15-Nov-12	87.0	0.4	86.6	99.55	5.83%	87.0	0.0	73.6	4.3	
4	17-Sep-02	6.930%	1-Jun-32	58.0	(2.2)	60.2	103.71	6.64%	58.0	58.0	58.0	3.9	
5	31-Jan-03	5.770%	15-Nov-12	189.0	(0.9)	189.9	100.48	5.70%	189.0	0.0	159.9	9.1	
6	31-Jan-03	6.350%	31-Jan-34	126.0	1.0	125.0	99.21	6.41%	126.0	126.0	126.0	8.1	
7	22-Apr-03	6.590%	22-Apr-43	145.0	1.1	143.9	99.26	6.64%	145.0	145.0	145.0	9.6	
8	25-Jun-04	6.350%	31-Jan-34	72.0	(0.2)	72.2	100.22	6.33%	72.0	72.0	72.0	4.6	
9	20-Aug-04	6.590%	22-Apr-43	39.0	(3.1)	42.1	107.89	6.06%	39.0	39.0	39.0	2.4	
10	24-Aug-04	6.350%	31-Jan-34	39.0	(1.4)	40.4	103.48	6.09%	39.0	39.0	39.0	2.4	
11	19-May-05	5.360%	20-May-36	228.9	8.7	220.2	96.19	5.62%	228.9	228.9	228.9	12.9	
12	3-Mar-06	4.640%	3-Mar-16	210.0	1.0	209.0	99.52	4.70%	210.0	210.0	210.0	9.9	
13	24-Apr-06	5.360%	20-May-36	187.5	2.5	185.0	98.68	5.45%	187.5	187.5	187.5	10.2	
14	22-Aug-06	4.640%	3-Mar-16	60.0	0.8	59.2	98.75	4.80%	60.0	60.0	60.0	2.9	
15	19-Oct-06	5.000%	19-Oct-46	30.0	0.2	29.8	99.29	5.04%	30.0	30.0	30.0	1.5	
16	13-Mar-07	4.890%	13-Mar-37	240.0	1.3	238.7	99.45	4.93%	240.0	240.0	240.0	11.8	
17	18-Oct-07	5.180%	18-Oct-17	225.0	0.8	224.2	99.63	5.23%	225.0	225.0	225.0	11.8	
18	3-Mar-08	5.180%	18-Oct-17	180.0	(3.1)	183.1	101.73	4.95%	180.0	180.0	180.0	8.9	
19	10-Nov-08	5.000%	12-Nov-13	240.0	1.1	238.9	99.53	5.11%	240.0	240.0	240.0	12.3	
20	14-Jan-09	5.000%	12-Nov-13	130.0	(3.7)	133.7	102.85	4.34%	130.0	130.0	130.0	5.6	
21	3-Mar-09	6.030%	3-Mar-39	195.0	1.2	193.8	99.41	6.07%	195.0	195.0	195.0	11.8	
22	16-Jul-09	5.490%	16-Jul-40	210.0	1.4	208.6	99.36	5.53%	210.0	210.0	210.0	11.6	
23	19-Nov-09	3.130%	19-Nov-14	175.0	0.7	174.3	99.63	3.21%	175.0	175.0	175.0	5.6	
24	15-Mar-10	5.490%	24-Jul-40	120.0	(0.7)	120.7	100.58	5.45%	120.0	120.0	120.0	6.5	
25	15-Mar-10	4.400%	4-Jun-20	180.0	0.8	179.2	99.55	4.46%	180.0	180.0	180.0	8.0	
26	13-Sep-10	2.950%	11-Sep-15	150.0	0.6	149.4	99.62	3.03%	150.0	150.0	150.0	4.5	
27	13-Sep-10	5.000%	19-Oct-46	150.0	(0.4)	150.4	100.25	4.98%	150.0	150.0	150.0	7.5	
28	26-Sep-11	4.390%	26-Sep-41	205.0	1.3	203.7	99.36	4.43%	205.0	205.0	205.0	9.1	
29	22-Dec-11	4.000%	22-Dec-51	70.0	0.4	69.6	99.48	4.03%	70.0	70.0	70.0	2.8	
30	13-Jan-12	3.200%	13-Jan-22	154.0	0.8	153.2	99.49	3.26%	0.0	154.0	142.2	4.6	
31	22-May-12	3.200%	13-Jan-22	165.0	(1.6)	166.6	100.99	3.08%	0.0	165.0	101.5	3.1	
32	22-May-12	4.000%	22-Dec-51	68.8	0.3	68.4	99.52	4.02%	0.0	68.8	42.3	1.7	
33	31-Jul-12	3.790%	31-Jul-62	52.5	0.3	52.2	99.52	3.81%	0.0	52.5	24.2	0.9	
34	16-Aug-12	3.790%	31-Jul-62	141.0	1.1	139.9	99.21	3.83%	0.0	141.0	54.2	2.1	
35	15-Sep-12	2.181%	16-Mar-18	258.4	1.3	257.1	99.50	2.28%	0.0	258.4	79.5	1.8	
36		**Subtotal**							4329.1	4892.7	4730.6	242.4	
37		Treasury OM&A costs										1.6	
38		Other financing-related fees										3.9	
39		**Total**							4329.1	4892.7	4730.6	247.8	5.24%

HYDRO ONE NETWORKS INC.
TRANSMISSION
Cost of Long-Term Debt Capital
Test Year (2013)
Year ending December 31

c)

Line No.	Offering Date	Coupon Rate	Maturity Date	Principal Amount Offered ($Millions)	Premium Discount and Expenses ($Millions)	Net Capital Employed: Total Amount ($Millions)	Net Capital Employed: Per $100 Principal Amount (Dollars)	Effective Cost Rate	Total Amount Outstanding: at 12/31/12 ($Millions)	Total Amount Outstanding: at 12/31/13 ($Millions)	Avg. Monthly Averages ($Millions)	Carrying Cost ($Millions)	Projected Average Embedded Cost Rates
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
1	3-Jun-00	7.350%	3-Jun-30	278.4	4.5	273.9	98.37	7.49%	278.4	278.4	278.4	20.8	
2	22-Jun-01	6.930%	1-Jun-32	109.3	1.0	108.2	99.05	7.01%	109.3	109.3	109.3	7.7	
3	17-Sep-02	6.930%	1-Jun-32	58.0	(2.2)	60.2	103.71	6.64%	58.0	58.0	58.0	3.9	
4	31-Jan-03	6.350%	31-Jan-34	126.0	1.0	125.0	99.21	6.41%	126.0	126.0	126.0	8.1	
5	22-Apr-03	6.590%	22-Apr-43	145.0	1.1	143.9	99.26	6.64%	145.0	145.0	145.0	9.6	
6	25-Jun-04	6.350%	31-Jan-34	72.0	(0.2)	72.2	100.22	6.33%	72.0	72.0	72.0	4.6	
7	20-Aug-04	6.590%	22-Apr-43	39.0	(3.1)	42.1	107.89	6.06%	39.0	39.0	39.0	2.4	
8	24-Aug-04	6.350%	31-Jan-34	39.0	(1.4)	40.4	103.48	6.09%	39.0	39.0	39.0	2.4	
9	19-May-05	5.360%	20-May-36	228.9	8.7	220.2	96.19	5.62%	228.9	228.9	228.9	12.9	
10	3-Mar-06	4.640%	3-Mar-16	210.0	1.0	209.0	99.52	4.70%	210.0	210.0	210.0	9.9	
11	24-Apr-06	5.360%	20-May-36	187.5	2.5	185.0	98.68	5.45%	187.5	187.5	187.5	10.2	
12	22-Aug-06	4.640%	3-Mar-16	60.0	0.8	59.2	98.75	4.80%	60.0	60.0	60.0	2.9	
13	19-Oct-06	5.000%	19-Oct-46	30.0	0.2	29.8	99.29	5.04%	30.0	30.0	30.0	1.5	
14	13-Mar-07	4.890%	13-Mar-37	240.0	1.3	238.7	99.45	4.93%	240.0	240.0	240.0	11.8	
15	18-Oct-07	5.180%	18-Oct-17	225.0	0.8	224.2	99.63	5.23%	225.0	225.0	225.0	11.8	
16	3-Mar-08	5.180%	18-Oct-17	180.0	(3.1)	183.1	101.73	4.95%	180.0	180.0	180.0	8.9	
17	10-Nov-08	5.000%	12-Nov-13	240.0	1.1	238.9	99.53	5.11%	240.0	0.0	203.1	10.4	
18	14-Jan-09	5.000%	12-Nov-13	130.0	(3.7)	133.7	102.85	4.34%	130.0	0.0	110.0	4.8	
19	3-Mar-09	6.030%	3-Mar-39	195.0	1.2	193.8	99.41	6.07%	195.0	195.0	195.0	11.8	
20	16-Jul-09	5.490%	16-Jul-40	210.0	1.4	208.6	99.36	5.53%	210.0	210.0	210.0	11.6	
21	19-Nov-09	3.130%	19-Nov-14	175.0	0.7	174.3	99.63	3.21%	175.0	175.0	175.0	5.6	
22	15-Mar-10	5.490%	24-Jul-40	120.0	(0.7)	120.7	100.58	5.45%	120.0	120.0	120.0	6.5	
23	15-Mar-10	4.400%	4-Jun-20	180.0	0.8	179.2	99.55	4.46%	180.0	180.0	180.0	8.0	
24	13-Sep-10	2.950%	11-Sep-15	150.0	0.6	149.4	99.62	3.03%	150.0	150.0	150.0	4.5	
25	13-Sep-10	5.000%	19-Oct-46	150.0	(0.4)	150.4	100.25	4.98%	150.0	150.0	150.0	7.5	
26	26-Sep-11	4.390%	26-Sep-41	205.0	1.3	203.7	99.36	4.43%	205.0	205.0	205.0	9.1	
27	22-Dec-11	4.000%	22-Dec-51	70.0	0.4	69.6	99.48	4.03%	70.0	70.0	70.0	2.8	
28	13-Jan-12	3.200%	13-Jan-22	154.0	0.8	153.2	99.49	3.26%	154.0	154.0	154.0	5.0	
29	22-May-12	3.200%	13-Jan-22	165.0	(1.6)	166.6	100.99	3.08%	165.0	165.0	165.0	5.1	
30	22-May-12	4.000%	22-Dec-51	68.8	0.3	68.4	99.52	4.02%	68.8	68.8	68.8	2.8	
31	31-Jul-12	3.790%	31-Jul-62	52.5	0.3	52.2	99.52	3.81%	52.5	52.5	52.5	2.0	
32	16-Aug-12	3.790%	31-Jul-62	141.0	1.1	139.9	99.21	3.83%	141.0	141.0	141.0	5.4	
33	15-Sep-12	2.181%	16-Mar-18	258.4	1.3	257.1	99.50	2.28%	258.4	258.4	258.4	5.9	
34	15-Mar-13	4.068%	15-Mar-43	388.4	1.9	386.4	99.50	4.10%	0.0	388.4	298.8	12.2	
35	15-Jun-13	3.152%	15-Jun-23	388.4	1.9	386.4	99.50	3.21%	0.0	388.4	209.1	6.7	
36	15-Sep-13	2.431%	15-Sep-18	150.0	0.8	149.3	99.50	2.54%	0.0	150.0	46.2	1.2	
37		**Subtotal**							4892.7	5449.5	5389.8	258.2	
38		Treasury OM&A costs										1.6	
39		Other financing-related fees										3.6	
40		**Total**							4892.7	5449.5	5389.8	263.4	4.89%

HYDRO ONE NETWORKS INC.
TRANSMISSION
Cost of Long-Term Debt Capital
Test Year (2014)
Year ending December 31

Line No.	Offering Date	Coupon Rate	Maturity Date	Principal Amount Offered ($Millions)	Premium Discount and Expenses ($Millions)	Net Capital Employed: Total Amount ($Millions)	Net Capital Employed: Per $100 Principal Amount (Dollars)	Effective Cost Rate	Total Amount Outstanding at 12/31/13 ($Millions)	Total Amount Outstanding at 12/31/14 ($Millions)	Avg. Monthly Averages ($Millions)	Carrying Cost ($Millions)	Projected Average Embedded Cost Rates
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
1	3-Jun-00	7.350%	3-Jun-30	278.4	4.5	273.9	98.37	7.49%	278.4	278.4	278.4	20.8	
2	22-Jun-01	6.930%	1-Jun-32	109.3	1.0	108.2	99.05	7.01%	109.3	109.3	109.3	7.7	
3	17-Sep-02	6.930%	1-Jun-32	58.0	(2.2)	60.2	103.71	6.64%	58.0	58.0	58.0	3.9	
4	31-Jan-03	6.350%	31-Jan-34	126.0	1.0	125.0	99.21	6.41%	126.0	126.0	126.0	8.1	
5	22-Apr-03	6.590%	22-Apr-43	145.0	1.1	143.9	99.26	6.64%	145.0	145.0	145.0	9.6	
6	25-Jun-04	6.350%	31-Jan-34	72.0	(0.2)	72.2	100.22	6.33%	72.0	72.0	72.0	4.6	
7	20-Aug-04	6.590%	22-Apr-43	39.0	(3.1)	42.1	107.89	6.06%	39.0	39.0	39.0	2.4	
8	24-Aug-04	6.350%	31-Jan-34	39.0	(1.4)	40.4	103.48	6.09%	39.0	39.0	39.0	2.4	
9	19-May-05	5.360%	20-May-36	228.9	8.7	220.2	96.19	5.62%	228.9	228.9	228.9	12.9	
10	3-Mar-06	4.640%	3-Mar-16	210.0	1.0	209.0	99.52	4.70%	210.0	210.0	210.0	9.9	
11	24-Apr-06	5.360%	20-May-36	187.5	2.5	185.0	98.68	5.45%	187.5	187.5	187.5	10.2	
12	22-Aug-06	4.640%	3-Mar-16	60.0	0.8	59.2	98.75	4.80%	60.0	60.0	60.0	2.9	
13	19-Oct-06	5.000%	19-Oct-46	30.0	0.2	29.8	99.29	5.04%	30.0	30.0	30.0	1.5	
14	13-Mar-07	4.890%	13-Mar-37	240.0	1.3	238.7	99.45	4.93%	240.0	240.0	240.0	11.8	
15	18-Oct-07	5.180%	18-Oct-17	225.0	0.8	224.2	99.63	5.23%	225.0	225.0	225.0	11.8	
16	3-Mar-08	5.180%	18-Oct-17	180.0	(3.1)	183.1	101.73	4.95%	180.0	180.0	180.0	8.9	
17	3-Mar-09	6.030%	3-Mar-39	195.0	1.2	193.8	99.41	6.07%	195.0	195.0	195.0	11.8	
18	16-Jul-09	5.490%	16-Jul-40	210.0	1.4	208.6	99.36	5.53%	210.0	210.0	210.0	11.6	
19	19-Nov-09	3.130%	19-Nov-14	175.0	0.7	174.3	99.63	3.21%	175.0	0.0	148.1	4.8	
20	15-Mar-10	5.490%	24-Jul-40	120.0	(0.7)	120.7	100.58	5.45%	120.0	120.0	120.0	6.5	
21	15-Mar-10	4.400%	4-Jun-20	180.0	0.8	179.2	99.55	4.46%	180.0	180.0	180.0	8.0	
22	13-Sep-10	2.950%	11-Sep-15	150.0	0.6	149.4	99.62	3.03%	150.0	150.0	150.0	4.5	
23	13-Sep-10	5.000%	19-Oct-46	150.0	(0.4)	150.4	100.25	4.98%	150.0	150.0	150.0	7.5	
24	26-Sep-11	4.390%	26-Sep-41	205.0	1.3	203.7	99.36	4.43%	205.0	205.0	205.0	9.1	
25	22-Dec-11	4.000%	22-Dec-51	70.0	0.4	69.6	99.48	4.03%	70.0	70.0	70.0	2.8	
26	13-Jan-12	3.200%	13-Jan-22	154.0	0.8	153.2	99.49	3.26%	154.0	154.0	154.0	5.0	
27	22-May-12	3.200%	13-Jan-22	165.0	(1.6)	166.6	100.99	3.08%	165.0	165.0	165.0	5.1	
28	22-May-12	4.000%	22-Dec-51	68.8	0.3	68.4	99.52	4.02%	68.8	68.8	68.8	2.8	
29	31-Jul-12	3.790%	31-Jul-62	52.5	0.3	52.2	99.52	3.81%	52.5	52.5	52.5	2.0	
30	16-Aug-12	3.790%	31-Jul-62	141.0	1.1	139.9	99.21	3.83%	141.0	141.0	141.0	5.4	
31	15-Sep-12	2.181%	16-Mar-18	258.4	1.3	257.1	99.50	2.28%	258.4	258.4	258.4	5.9	
32	15-Mar-13	4.068%	15-Mar-43	388.4	1.9	386.4	99.50	4.10%	388.4	388.4	388.4	15.9	
33	15-Jun-13	3.152%	15-Jun-23	388.4	1.9	386.4	99.50	3.21%	388.4	388.4	388.4	12.5	
34	15-Sep-13	2.431%	15-Sep-18	150.0	0.8	149.3	99.50	2.54%	150.0	150.0	150.0	3.8	
35	15-Mar-14	5.618%	15-Mar-44	289.8	1.4	288.4	99.50	5.65%	0.0	289.8	223.0	12.6	
36	15-Jun-14	4.702%	15-Jun-24	289.8	1.4	288.4	99.50	4.77%	0.0	289.8	156.1	7.4	
37	15-Sep-14	3.981%	15-Sep-19	289.8	1.4	288.4	99.50	4.09%	0.0	289.8	89.2	3.6	
38		**Subtotal**							5449.5	6144.0	5890.8	277.9	
39		Treasury OM&A costs										1.7	
40		Other financing-related fees										3.3	
41		**Total**							5449.5	6144.0	5890.8	282.9	4.80%

Energy Probe (EP) INTERROGATORY #58 List 1

Issue 18 Is the forecast of long term debt for 2012-2014 appropriate?

Interrogatory

Ref: Exhibit B1, Tab 2, Schedule 1, Page 3 &
Exhibit B2, Tab 1,Schedule 2, Page 4

a) For historical 2011 and bridge year 2012 debt (B2/1/2 page 4 at lines 28-29) please provide a schedule that shows for each issue, the difference between the Board Approved forecast and actual *(or* if not yet issued, current forecast):
    i) Amount of issue per EB-2010-0002;
    ii) Coupon rate forecast actual and approved by the Board;
    iii) The premium discount and expenses;
    iv) The total principal amount, and
    v) The annual carrying cost.

b) For material differences in the schedule please provide an explanation, including in particular:
    i) The external forecasts relied upon;
    ii) Timing differences, and
    iii) Bond premiums.

Response

a) The schedules in Attachment 1 provide the requested issue details: the amount per issue, coupon rate, premium discount and expenses, total principal amounts and carrying costs.

   Board approved 2011 issue details are shown on lines 29 to 31 of page 1, Exhibit 1.4.1, EB-2010-0002 Rate Order. Actual issue details for 2011 are shown on lines 29 to 30 of page 3 Exhibit B2, Tab 1, Schedule 2, EB-2012-0031.

   Board approved 2012 issue details are shown on lines 28 to 32 of page 1, Exhibit 1.4.1, EB-2011-0268 Rate Order. Actual and current assumption issue details for 2012 are shown on lines 28 to 33 of page 4 Exhibit B2, Tab 1, Schedule 2, EB-2012-0031. Updated bridge year 2012 to reflect actual debt issues in 2012 and most recent forecasts is provided in part b of Exhibit I, Tab 18, Schedule 2.03 LPMA 31.

b) The overall rate for 2011 of 5.52% contained in Exhibit 1.4.1, EB-2010-0002 Rate Order was 0.05% lower than the 5.57% historical rate in Exhibit B2, Tab 1, Schedule 2.

The overall rate for 2012 of 5.37% contained in Exhibit 1.4.1, EB-2011-0268 Rate Order was 0.14% higher than the 5.23% rate contained in Exhibit B2, Tab 1, Schedule 2, due to lowering of forecast interest rates for 2012. The overall rate for 2012 updated to reflect actual debt issues in 2012 and most recent forecasts as provided on page 2 or part b of Exhibit I, Tab 18, Schedule 2.03 LPMA 31 is 5.24%.

EB-2010-0002 Draft Rate Order Exhibit 1.4.1

EB-2011-0268 2012 Rate Order Exhibit 1.4.1

EB-2012-0031 Exhibit B2, Tab 1, Schedule 2, Page 3-4

Hydro One Networks Inc.
Transmission
Cost of Long-Term Debt Capital
Test Year (2011)
Year ending December 31

Line No.	Offering Date	Coupon Rate	Maturity Date	Principal Amount Offered ($Millions)	Premium Discount and Expenses ($Millions)	Net Capital Employed: Total Amount ($Millions)	Net Capital Employed: Per $100 Principal Amount (Dollars)	Effective Cost Rate	Total Amount Outstanding: at 12/31/10 ($Millions)	Total Amount Outstanding: at 12/31/11 ($Millions)	Avg. Monthly Averages ($Millions)	Carrying Cost ($Millions)	Projected Average Embedded Cost Rates
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
1	3-Jun-00	7.350%	3-Jun-30	278.4	4.5	273.9	98.37	7.49%	278.4	278.4	278.4	20.8	
2	22-Jun-01	6.400%	1-Dec-11	174.0	(0.5)	174.5	100.28	6.36%	174.0	0.0	160.6	10.2	
3	22-Jun-01	6.930%	1-Jun-32	109.3	1.0	108.2	99.05	7.01%	109.3	109.3	109.3	7.7	
4	17-Sep-02	5.770%	15-Nov-12	87.0	0.4	86.6	99.55	5.83%	87.0	87.0	87.0	5.1	
5	17-Sep-02	6.930%	1-Jun-32	58.0	(2.2)	60.2	103.71	6.64%	58.0	58.0	58.0	3.9	
6	31-Jan-03	5.770%	15-Nov-12	189.0	(0.9)	189.9	100.48	5.70%	189.0	189.0	189.0	10.8	
7	31-Jan-03	6.350%	31-Jan-34	126.0	1.0	125.0	99.21	6.41%	126.0	126.0	126.0	8.1	
8	22-Apr-03	6.590%	22-Apr-43	145.0	1.1	143.9	99.26	6.64%	145.0	145.0	145.0	9.6	
9	25-Jun-04	6.350%	31-Jan-34	72.0	(0.2)	72.2	100.22	6.33%	72.0	72.0	72.0	4.6	
10	20-Aug-04	6.590%	22-Apr-43	39.0	(3.1)	42.1	107.89	6.06%	39.0	39.0	39.0	2.4	
11	24-Aug-04	6.350%	31-Jan-34	39.0	(1.4)	40.4	103.48	6.09%	39.0	39.0	39.0	2.4	
12	19-May-05	5.360%	20-May-36	228.9	8.2	220.7	96.44	5.60%	228.9	228.9	228.9	12.8	
13	3-Mar-06	4.640%	3-Mar-16	210.0	1.0	209.0	99.52	4.70%	210.0	210.0	210.0	9.9	
14	24-Apr-06	5.360%	20-May-36	187.5	2.5	185.0	98.68	5.45%	187.5	187.5	187.5	10.2	
15	22-Aug-06	4.640%	3-Mar-16	60.0	0.8	59.2	98.75	4.80%	60.0	60.0	60.0	2.9	
16	19-Oct-06	5.000%	19-Oct-46	30.0	0.2	29.8	99.29	5.04%	30.0	30.0	30.0	1.5	
17	13-Mar-07	4.890%	13-Mar-37	240.0	1.3	238.7	99.45	4.93%	240.0	240.0	240.0	11.8	
18	18-Oct-07	5.180%	18-Oct-17	225.0	0.8	224.2	99.63	5.23%	225.0	225.0	225.0	11.8	
19	3-Mar-08	5.180%	18-Oct-17	180.0	(3.1)	183.1	101.73	4.95%	180.0	180.0	180.0	8.9	
20	10-Nov-08	5.000%	12-Nov-13	240.0	1.1	238.9	99.53	5.11%	240.0	240.0	240.0	12.3	
21	14-Jan-09	5.000%	12-Nov-13	130.0	(3.7)	133.7	102.87	4.33%	130.0	130.0	130.0	5.6	
22	3-Mar-09	6.030%	3-Mar-39	195.0	1.1	193.9	99.43	6.07%	195.0	195.0	195.0	11.8	
23	16-Jul-09	5.490%	16-Jul-40	210.0	1.3	208.7	99.37	5.53%	210.0	210.0	210.0	11.6	
24	19-Nov-09	3.130%	19-Nov-14	175.0	0.6	174.4	99.64	3.21%	175.0	175.0	175.0	5.6	
25	15-Mar-10	5.490%	16-Jul-40	120.0	(0.7)	120.7	100.59	5.45%	120.0	120.0	120.0	6.5	
26	15-Mar-10	4.400%	1-Jun-20	180.0	0.8	179.2	99.56	4.45%	180.0	180.0	180.0	8.0	
27	13-Sep-10	2.950%	11-Sep-15	150.0	0.5	149.5	99.64	3.03%	150.0	150.0	150.0	4.5	Note 1
28	13-Sep-10	5.000%	19-Oct-46	150.0	(0.4)	150.4	100.27	4.98%	150.0	150.0	150.0	7.5	Note 1
29	15-Mar-11	5.370%	15-Mar-41	300.0	1.5	298.5	99.50	5.40%	0.0	300.0	230.8	12.5	Note 2
30	15-Jun-11	4.460%	15-Jun-21	300.0	1.5	298.5	99.50	4.52%	0.0	300.0	161.5	7.3	Note 2
31	15-Sep-11	3.410%	15-Sep-16	300.0	1.5	298.5	99.50	3.52%	0.0	300.0	92.3	3.2	Note 2
32		**Subtotal**							4228.1	4954.1	4699.3	251.8	
33		Treasury OM&A costs										2.1	
34		Other financing-related fees										5.7	
35		**Total**							4228.1	4954.1	4699.3	259.5	5.52%

Note 1: Updated to reflect actual 2010 debt issuance

Note 2: Updated to reflect the forecast coupon rates for 2011 as per the September 2010 Consensus Forecast

HYDRO ONE NETWORKS INC.
TRANSMISSION
Cost of Long-Term Debt Capital
Test Year (2012)
Year ending December 31

Line No.	Offering Date (a)	Coupon Rate (b)	Maturity Date (c)	Principal Amount Offered ($Millions) (d)	Premium Discount and Expenses ($Millions) (e)	Net Capital Employed: Total Amount ($Millions) (f)	Net Capital Employed: Per $100 Principal Amount (Dollars) (g)	Effective Cost Rate (h)	Total Amount Outstanding at 12/31/11 ($Millions) (i)	Total Amount Outstanding at 12/31/12 ($Millions) (j)	Avg. Monthly Averages ($Millions) (k)	Carrying Cost ($Millions) (l)	Projected Average Embedded Cost Rates (m)
1	3-Jun-00	7.350%	3-Jun-30	278.4	4.5	273.9	98.37	7.49%	278.4	278.4	278.4	20.8	
2	22-Jun-01	6.930%	1-Jun-32	109.3	1.0	108.2	99.05	7.01%	109.3	109.3	109.3	7.7	
3	17-Sep-02	5.770%	15-Nov-12	87.0	0.4	86.6	99.55	5.83%	87.0	0.0	73.6	4.3	
4	17-Sep-02	6.930%	1-Jun-32	58.0	(2.2)	60.2	103.71	6.64%	58.0	58.0	58.0	3.9	
5	31-Jan-03	5.770%	15-Nov-12	189.0	(0.9)	189.9	100.48	5.70%	189.0	0.0	159.9	9.1	
6	31-Jan-03	6.350%	31-Jan-34	126.0	1.0	125.0	99.21	6.41%	126.0	126.0	126.0	8.1	
7	22-Apr-03	6.590%	22-Apr-43	145.0	1.1	143.9	99.26	6.64%	145.0	145.0	145.0	9.6	
8	25-Jun-04	6.350%	31-Jan-34	72.0	(0.2)	72.2	100.22	6.33%	72.0	72.0	72.0	4.6	
9	20-Aug-04	6.590%	22-Apr-43	39.0	(3.1)	42.1	107.89	6.06%	39.0	39.0	39.0	2.4	
10	24-Aug-04	6.350%	31-Jan-34	39.0	(1.4)	40.4	103.48	6.09%	39.0	39.0	39.0	2.4	
11	19-May-05	5.360%	20-May-36	228.9	8.2	220.7	96.44	5.60%	228.9	228.9	228.9	12.8	
12	3-Mar-06	4.640%	3-Mar-16	210.0	1.0	209.0	99.52	4.70%	210.0	210.0	210.0	9.9	
13	24-Apr-06	5.360%	20-May-36	187.5	2.5	185.0	98.68	5.45%	187.5	187.5	187.5	10.2	
14	22-Aug-06	4.640%	3-Mar-16	60.0	0.8	59.2	98.75	4.80%	60.0	60.0	60.0	2.9	
15	19-Oct-06	5.000%	19-Oct-46	30.0	0.2	29.8	99.29	5.04%	30.0	30.0	30.0	1.5	
16	13-Mar-07	4.890%	13-Mar-37	240.0	1.3	238.7	99.45	4.93%	240.0	240.0	240.0	11.8	
17	18-Oct-07	5.180%	18-Oct-17	225.0	0.8	224.2	99.63	5.23%	225.0	225.0	225.0	11.8	
18	3-Mar-08	5.180%	18-Oct-17	180.0	(3.1)	183.1	101.73	4.95%	180.0	180.0	180.0	8.9	
19	10-Nov-08	5.000%	12-Nov-13	240.0	1.1	238.9	99.53	5.11%	240.0	240.0	240.0	12.3	
20	14-Jan-09	5.000%	12-Nov-13	130.0	(3.7)	133.7	102.87	4.33%	130.0	130.0	130.0	5.6	
21	3-Mar-09	6.030%	3-Mar-39	195.0	1.1	193.9	99.43	6.07%	195.0	195.0	195.0	11.8	
22	16-Jul-09	5.490%	16-Jul-40	210.0	1.3	208.7	99.37	5.53%	210.0	210.0	210.0	11.6	
23	19-Nov-09	3.130%	19-Nov-14	175.0	0.6	174.4	99.64	3.21%	175.0	175.0	175.0	5.6	
24	15-Mar-10	5.490%	16-Jul-40	120.0	(0.7)	120.7	100.59	5.45%	120.0	120.0	120.0	6.5	
25	15-Mar-10	4.400%	1-Jun-20	180.0	0.8	179.2	99.56	4.45%	180.0	180.0	180.0	8.0	
26	13-Sep-10	2.950%	11-Sep-15	150.0	0.5	149.5	99.64	3.03%	150.0	150.0	150.0	4.5	
27	13-Sep-10	5.000%	19-Oct-46	150.0	(0.4)	150.4	100.27	4.98%	150.0	150.0	150.0	7.5	
28	26-Sep-11	4.390%	26-Sep-41	205.0	1.3	203.7	99.36	4.43%	205.0	205.0	205.0	9.1	Note 1
29	15-Dec-11	3.786%	15-Dec-21	175.0	0.9	174.1	99.50	3.85%	175.0	175.0	175.0	6.7	Note 1
30	15-Mar-12	4.957%	15-Mar-42	225.0	1.1	223.9	99.50	4.99%	0.0	225.0	173.1	8.6	Note 2
31	15-Jun-12	3.936%	15-Jun-22	225.0	1.1	223.9	99.50	4.00%	0.0	225.0	121.2	4.8	Note 2
32	15-Sep-12	2.900%	15-Sep-17	225.0	1.1	223.9	99.50	3.01%	0.0	225.0	69.2	2.1	Note 2
33		**Subtotal**							4434.1	4833.2	4755.1	247.5	
34		Treasury OM&A costs										2.1	
35		Other financing-related fees										5.7	
36		**Total**							4434.1	4833.2	4755.1	255.3	5.37%

Note 1: As per EB-2010-0002 Decision with Reasons on December 23, 2010, long-term debt rates have been updated to reflect actual 2011 debt issuances.
Note 2: Rates have been updated to reflect September 2011 Consensus forecast as per OEB's November 10, 2011 direction on cost of capital parameters.

HYDRO ONE NETWORKS INC.
TRANSMISSION
Cost of Long-Term Debt Capital
Historical Year (2011)
Year ending December 31

Line No.	Offering Date	Coupon Rate	Maturity Date	Principal Amount Offered ($Millions)	Premium Discount and Expenses ($Millions)	Net Capital Employed: Total Amount ($Millions)	Net Capital Employed: Per $100 Principal Amount (Dollars)	Effective Cost Rate	Total Amount Outstanding: at 12/31/10 ($Millions)	Total Amount Outstanding: at 12/31/11 ($Millions)	Avg. Monthly Averages ($Millions)	Carrying Cost ($Millions)	Projected Average Embedded Cost Rates
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
1	3-Jun-00	7.150%	3-Jun-30	278.4	4.5	273.9	98.37	7.49%	278.4	278.4	278.4	20.8	
2	22-Jun-01	6.400%	1-Dec-11	174.0	(0.5)	174.5	100.28	6.36%	174.0	0.0	160.6	10.2	
3	22-Jun-01	6.930%	1-Jun-32	109.3	1.0	108.2	99.05	7.01%	109.3	109.3	109.3	7.7	
4	17-Sep-02	5.770%	15-Nov-12	87.0	0.4	86.6	99.55	5.83%	87.0	87.0	87.0	5.1	
5	17-Sep-02	6.930%	1-Jun-32	58.0	(2.2)	60.2	103.71	6.64%	58.0	58.0	58.0	3.9	
6	31-Jan-03	5.770%	15-Nov-12	189.0	(0.9)	189.9	100.48	5.70%	189.0	189.0	189.0	10.8	
7	31-Jan-03	6.350%	31-Jan-34	126.0	1.0	125.0	99.21	6.41%	126.0	126.0	126.0	8.1	
8	22-Apr-03	6.590%	22-Apr-43	145.0	1.1	143.9	99.26	6.64%	145.0	145.0	145.0	9.6	
9	25-Jun-04	6.350%	31-Jan-34	72.0	(0.2)	72.2	100.22	6.33%	72.0	72.0	72.0	4.6	
10	20-Aug-04	6.590%	22-Apr-43	39.0	(3.1)	42.1	107.89	6.06%	39.0	39.0	39.0	2.4	
11	24-Aug-04	6.350%	31-Jan-34	39.0	(1.4)	40.4	103.48	6.09%	39.0	39.0	39.0	2.4	
12	19-May-05	5.360%	20-May-36	228.9	8.2	220.7	96.44	5.60%	228.9	228.9	228.9	12.8	
13	3-Mar-06	4.640%	3-Mar-16	210.0	1.0	209.0	99.52	4.70%	210.0	210.0	210.0	9.9	
14	24-Apr-06	5.360%	20-May-36	187.5	2.5	185.0	98.68	5.45%	187.5	187.5	187.5	10.2	
15	22-Aug-06	4.640%	3-Mar-16	60.0	0.8	59.2	98.75	4.80%	60.0	60.0	60.0	2.9	
16	19-Oct-06	5.000%	19-Oct-46	30.0	0.2	29.8	99.29	5.04%	30.0	30.0	30.0	1.5	
17	13-Mar-07	4.890%	13-Mar-37	240.0	1.3	238.7	99.45	4.93%	240.0	240.0	240.0	11.8	
18	18-Oct-07	5.180%	18-Oct-17	225.0	0.8	224.2	99.66	5.22%	225.0	225.0	225.0	11.8	
19	3-Mar-08	5.180%	18-Oct-17	180.0	(3.1)	183.1	101.73	4.95%	180.0	180.0	138.5	6.9	
20	10-Nov-08	5.000%	12-Nov-13	240.0	1.1	238.9	99.53	5.11%	240.0	240.0	240.0	12.3	
21	14-Jan-09	5.000%	12-Nov-13	130.0	(3.7)	133.7	102.87	4.33%	130.0	130.0	130.0	5.6	
22	3-Mar-09	6.030%	3-Mar-39	195.0	1.1	193.9	99.43	6.07%	195.0	195.0	195.0	11.8	
23	16-Jul-09	5.490%	16-Jul-40	210.0	1.3	208.7	99.37	5.53%	210.0	210.0	210.0	11.6	
24	19-Nov-09	3.130%	19-Nov-14	175.0	0.6	174.4	99.64	3.21%	175.0	175.0	175.0	5.6	
25	15-Mar-10	5.490%	16-Jul-40	120.0	(0.7)	120.7	100.59	5.45%	120.0	120.0	120.0	6.5	
26	15-Mar-10	4.400%	1-Jun-20	180.0	0.8	179.2	99.56	4.45%	180.0	180.0	180.0	8.0	
27	13-Sep-10	2.950%	11-Sep-15	150.0	0.5	149.5	99.64	3.03%	150.0	150.0	150.0	4.5	
28	13-Sep-10	5.000%	19-Oct-46	150.0	(0.4)	150.4	100.27	4.98%	150.0	150.0	150.0	7.5	
29	26-Sep-11	4.390%	26-Sep-41	205.0	1.3	203.7	99.36	4.43%	0.0	205.0	63.1	2.8	
30	22-Dec-11	4.000%	22-Dec-51	70.0	0.4	69.6	99.48	4.03%	0.0	70.0	5.4	0.2	
31		**Subtotal**							4228.1	4329.1	4241.6	229.7	
32		Treasury OM&A costs										1.2	
33		Other financing-related fees										5.4	
34		**Total**							4228.1	4329.1	4241.6	236.3	5.57%

HYDRO ONE NETWORKS INC.
TRANSMISSION
Cost of Long-Term Debt Capital
Bridge Year (2012)
Year ending December 31

Line No.	Offering Date	Coupon Rate	Maturity Date	Principal Amount Offered ($Millions)	Premium Discount and Expenses ($Millions)	Net Capital Employed: Total Amount ($Millions)	Net Capital Employed: Per $100 Principal Amount (Dollars)	Effective Cost Rate	Total Amount Outstanding: at 12/31/11 ($Millions)	Total Amount Outstanding: at 12/31/12 ($Millions)	Avg. Monthly Averages ($Millions)	Carrying Cost ($Millions)	Projected Average Embedded Cost Rates
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
1	3-Jun-00	7.150%	3-Jun-30	278.4	4.5	273.9	98.37	7.49%	278.4	278.4	278.4	20.8	
2	22-Jun-01	6.930%	1-Jun-32	109.3	1.0	108.2	99.05	7.01%	109.3	109.3	109.3	7.7	
3	17-Sep-02	5.770%	15-Nov-12	87.0	0.4	86.6	99.55	5.83%	87.0	0.0	73.6	4.3	
4	17-Sep-02	6.930%	1-Jun-32	58.0	(2.2)	60.2	103.71	6.64%	58.0	58.0	58.0	3.9	
5	31-Jan-03	5.770%	15-Nov-12	189.0	(0.9)	189.9	100.48	5.70%	189.0	0.0	159.9	9.1	
6	31-Jan-03	6.350%	31-Jan-34	126.0	1.0	125.0	99.21	6.41%	126.0	126.0	126.0	8.1	
7	22-Apr-03	6.590%	22-Apr-43	145.0	1.1	143.9	99.26	6.64%	145.0	145.0	145.0	9.6	
8	25-Jun-04	6.350%	31-Jan-34	72.0	(0.2)	72.2	100.22	6.33%	72.0	72.0	72.0	4.6	
9	20-Aug-04	6.590%	22-Apr-43	39.0	(3.1)	42.1	107.89	6.06%	39.0	39.0	39.0	2.4	
10	24-Aug-04	6.350%	31-Jan-34	39.0	(1.4)	40.4	103.48	6.09%	39.0	39.0	39.0	2.4	
11	19-May-05	5.360%	20-May-36	228.9	8.7	220.2	96.19	5.62%	228.9	228.9	228.9	12.9	
12	3-Mar-06	4.640%	3-Mar-16	210.0	1.0	209.0	99.52	4.70%	210.0	210.0	210.0	9.9	
13	24-Apr-06	5.360%	20-May-36	187.5	2.5	185.0	98.68	5.45%	187.5	187.5	187.5	10.2	
14	22-Aug-06	4.640%	3-Mar-16	60.0	0.8	59.2	98.75	4.80%	60.0	60.0	60.0	2.9	
15	19-Oct-06	5.000%	19-Oct-46	30.0	0.2	29.8	99.29	5.04%	30.0	30.0	30.0	1.5	
16	13-Mar-07	4.890%	13-Mar-37	240.0	1.3	238.7	99.45	4.93%	240.0	240.0	240.0	11.8	
17	18-Oct-07	5.180%	18-Oct-17	225.0	0.8	224.2	99.63	5.23%	225.0	225.0	225.0	11.8	
18	3-Mar-08	5.180%	18-Oct-17	180.0	(3.1)	183.1	101.73	4.95%	180.0	180.0	180.0	8.9	
19	10-Nov-08	5.000%	12-Nov-13	240.0	1.1	238.9	99.53	5.11%	240.0	240.0	240.0	12.3	
20	14-Jan-09	5.000%	12-Nov-13	130.0	(3.7)	133.7	102.85	4.34%	130.0	130.0	130.0	5.6	
21	3-Mar-09	6.030%	3-Mar-39	195.0	1.2	193.8	99.41	6.07%	195.0	195.0	195.0	11.8	
22	16-Jul-09	5.490%	16-Jul-40	210.0	1.4	208.6	99.36	5.53%	210.0	210.0	210.0	11.6	
23	19-Nov-09	3.130%	19-Nov-14	175.0	0.7	174.3	99.63	3.21%	175.0	175.0	175.0	5.6	
24	15-Mar-10	5.490%	24-Jul-40	120.0	(0.7)	120.7	100.58	5.45%	120.0	120.0	120.0	6.5	
25	15-Mar-10	4.400%	4-Jun-20	180.0	0.8	179.2	99.55	4.46%	180.0	180.0	180.0	8.0	
26	13-Sep-10	2.950%	11-Sep-15	150.0	0.6	149.4	99.62	3.03%	150.0	150.0	150.0	4.5	
27	13-Sep-10	5.000%	19-Oct-46	150.0	(0.4)	150.4	100.25	4.98%	150.0	150.0	150.0	7.5	
28	26-Sep-11	4.390%	26-Sep-41	205.0	1.3	203.7	99.36	4.43%	205.0	205.0	205.0	9.1	
29	22-Dec-11	4.000%	22-Dec-51	70.0	0.4	69.6	99.48	4.03%	70.0	70.0	70.0	2.8	
30	13-Jan-12	3.200%	13-Jan-22	154.0	0.8	153.2	99.49	3.26%	0.0	154.0	142.2	4.6	
31	15-Mar-12	4.041%	15-Mar-42	230.3	1.2	229.2	99.50	4.07%	0.0	230.3	177.2	7.2	
32	15-Jun-12	3.164%	15-Jun-22	230.3	1.2	229.2	99.50	3.22%	0.0	230.3	124.0	4.0	
33	15-Sep-12	2.291%	16-Mar-18	225.0	1.1	223.9	99.50	2.39%	0.0	225.0	69.2	1.7	
33		**Subtotal**							4329.1	4892.7	4799.2	245.6	
34		Treasury OM&A costs										1.6	
35		Other financing-related fees										3.9	
36		**Total**							4329.1	4892.7	4799.2	251.0	5.23%

Energy Probe (EP) INTERROGATORY #59 List 1

Issue 18 Is the forecast of long term debt for 2012-2014 appropriate?

Interrogatory

Ref: Exhibit B1, Tab 2, Schedule 1, Page 5, Table 4 &
Exhibit B2, Tab 1, Schedule 2, Pages 5 and 6

a) Please provide a schedule that sets out the basis of the proposed coupon rates, other financing costs and annual carrying costs for all proposed 2013/14 debt issues:
   i) Sources and dates of forecasts of LC Bonds;
   ii) Sources and dates of forecast of Hydro One Spread and details of calculation, and
   iii) Sources and dates of forecast(s) of other financing costs.

b) Reconcile the answer with Tables 3 and 4 of B1/2/1.

c) When will Hydro One please provide an update of the forecast 2013/14 debt costs?

d) Explain in detail how the 2013/14 debt issues and costs are mapped to Hydro One Networks and to Hydro One Transmission.

e) Based on the 2013 and 2014 financing plan, please provide an estimate of the revenue requirement impact to Hydro One Transmission of a 10 basis point change in the average effective coupon rate.

Response

a) Table 4 of Exhibit B1, Tab 2, Schedule 1 provides basis of the proposed coupon rates.

   i) The basis for the Government of Canada Bond yields is discussed on lines 10 to 17 on page 5 of Exhibit Exhibit B1, Tab 2, Schedule 1.

   ii) The basis for the forecast of Hydro One Spreads is discussed on lines 1 to 4 on page 6 of Exhibit B1, Tab 2, Schedule 1.

   Please refer to Hydro One's response in Exhibit I, Tab 18, Schedule 9.02 SEC 37 for more details on the source documents and dates of forecast used.

   iii) The basis for the forecast of other financing charges is discussed in on lines 13 to 16 of page 7 Exhibit B1, Tab 2, Schedule 1.

Carrying Costs for all forecast 2013 and 2014 debt issues discussed in Exhibit B2, Tab 1, Schedule 2, Pages 5 and 6 is the product of columns (h) and columns (k)

b) The Forecast Hydro One Yields in tables 3 and 4 are equivalent to the coupon rates found in Exhibit B2, Tab 1, Schedule 2, Page 6 lines 30 – 35 column (a), rounded to 2 decimal places.

c) Hydro One will update the forecast debt rates in the final rate orders in accordance with the Board's approved methodology. For rates effective January 1, 2013, Hydro One will update the forecast interest rate using the September 2012 Consensus Forecasts and the average of indicative new issue spreads for September 2012. For rates effective January 1, 2014, Hydro One will update the forecast interest rate using the September 2013 Consensus Forecasts and the average of indicative new issue spreads for September 2013. The latest long-term debt forecast has been provided at Exhibit I, Tab 18, Schedule 2.03 LPMA 31.

d) The mapping of debt to Hydro One Networks is discussed on lines 7 to 9 on page 1 of Exhibit B1, Tab 2, Schedule 1. The allocation of debt to the Transmission business is discussed on lines 17 to 20 on page 2 of Exhibit B1, Tab 2, Schedule 1.

e) Please see response to Exhibit I, Tab 17, Schedule 2.01 LPMA 28.

Energy Probe (EP) INTERROGATORY #60 List 1

Issue 18 Is the forecast of long term debt for 2012-2014 appropriate?

Interrogatory

Ref. Exhibit B1, Tab 2, Schedule 1, Page 6

a) Please provide a schedule that shows Treasury OM&A costs by issue and year 2011A, 2012E and 2013-2014F.

b) What drives the cost per issue?

c) Given the Shelf Prospectus, will costs be lower in 2012-2014? If so, show how much. If not, why not?

Response

a) Treasury OM&A costs are not allocated to individual issues but are allocated to the entire debt portfolio as indicated on line 36, page 5 and line 37, page 6 of Exhibit B2, Tab 1, Schedule 2.

b) The cost per issue is driven by the Column (b) of Exhibit B2, Tab1, Schedule 2 (the coupon rate) and column (e) of Exhibit B2, Tab1, Schedule 2 (Premium, discount and expenses) which are discussed on lines 8 to 11, page 7 of Exhibit B1, Tab 2, Schedule 1.

c) Costs will not be lower in 2012 – 2014, given the shelf prospectus. Hydro One has issued debt using a Shelf Prospectus for its Medium Term Notes Program since 2001 and is expecting to continue issuing debt off of this same platform through to 2014 and beyond.

School Energy Coalition (SEC) INTERROGATORY #36 List 1

Issue 18 Is the forecast of long term debt for 2012-2014 appropriate?

Interrogatory

[B1-1-1/p.3]
Please provide a copy of all outstanding debt instruments issued since 2010.

Response

Please see attachments for the pricing supplements of the outstanding debt instruments issued since 2010.

On January 22, 2010 Hydro One Inc. issued $500 million of notes maturing on November 19, 2014 of which $150 million was mapped to Hydro One Transmission. At the time of the issue Hydro One entered into a $500 million notional principal amount fixed to floating interest rate swap to convert this note into variable or floating rate debt. This variable rate debt has been included as part of the deemed short-term debt amount equal to 4% of rate base.

On March 15, 2010 Hydro One Inc. issued $200 million of notes maturing on July 16, 2040 of which $120 million was mapped to Hydro One Transmission, as shown on line 24 of Exhibit B2, Tab 1, Schedule 2, page 4.

Also on March 15, 2010 Hydro One Inc. issued $300 million of notes maturing on June 1, 2020 with a 4.40% coupon rate of which $180 million was mapped to Hydro One Transmission, as shown on line 25 of Exhibit B2, Tab 1, Schedule 2, page 4.

On September 13, 2010 Hydro One Inc. issued $250 million of notes maturing on September 11, 2015 with a 2.95% coupon rate, of which $150 million was mapped to Hydro One Transmission, as shown on line 26 of Exhibit B2, Tab 1, Schedule 2, page 4.

Also on September 13, 2010 Hydro One Inc. issued $250 million of notes maturing on October 19, 2046 of which $150 million was mapped to Hydro One Transmission as shown on line 27 of Exhibit B2, Tab 1, Schedule 2, page 4.

On January 19, 2011 Hydro One Inc. issued $250 million of notes maturing on September 11, 2015 of which $150 million was mapped to Hydro One Transmission. At the time of the issue Hydro One entered into a $250 million notional principal amount fixed to floating interest rate swap to convert this note into variable or floating rate debt. This variable rate debt has been included as part of the deemed short-term debt amount equal to 4% of rate base.

On January 24, 2011 Hydro One Inc. issued $50 million of floating rate notes maturing on July 24, 2015 with a floating rate coupon of three month Canadian Dollar Offered Rate (CDOR) plus 40 basis points, of which $30 million was mapped to Hydro One Transmission. This variable rate debt has been included as part of the deemed short-term debt amount equal to 4% of rate base.

On September 26, 2011 Hydro One Inc. issued $300 million of notes maturing on September 26, 2041 with a coupon rate of 4.39% of which $205 million was mapped to Hydro One Transmission, as shown on line 28 of Exhibit B2, Tab 1, Schedule 2, page 4.

On December 22, 2011 Hydro One Inc. issued $100 million of notes maturing on December 22, 2051 with a coupon rate of 4.00% of which $70 million was mapped to Hydro One Transmission, as shown on line 29 of Exhibit B2, Tab 1, Schedule 2, page 4.

On January 13, 2012 Hydro One Inc. issued $300 million of notes maturing on January 13, 2022 with a coupon rate of 3.20% of which $154 million was mapped to Hydro One Transmission, as shown on line 30 of Exhibit B2, Tab 1, Schedule 2, page 4.

On May 22, 2012 Hydro One Inc. issued $300 million of notes maturing on January 13, 2022, of which $165 million was mapped to Hydro One Transmission as shown on line 31 of Exhibit I, Tab 18, Schedule 2.03 LPMA 31, page 2.

Also on May 22, 2012 Hydro One Inc. issued $125 million of notes maturing on December 22, 2051, of which $68.75 million was mapped to Hydro One Transmission as shown on line 32 of Exhibit I, Tab 18, Schedule 2.03 LPMA 31, page 2.

On July 31, 2012 Hydro One Inc. issued $75 million of notes maturing on July 31, 2062 with a coupon rate of 3.79% of which $52.5 million was mapped to Hydro One Transmission, as shown on line 33 of Exhibit I, Tab 18, Schedule 2.03 LPMA 31, page 2.

On August 16, 2012 Hydro One Inc. issued $235 million of notes maturing on July 31, 2062, of which $141 million was mapped to Hydro One Transmission as shown on line 34 of Exhibit I, Tab 18, Schedule 2.03 LPMA 31, page 2.

This pricing supplement, together with the short form base shelf prospectus dated July 27, 2009, as amended or supplemented, and each document incorporated by reference into the short form base shelf prospectus (collectively, the "Prospectus") constitutes a public offering of these securities pursuant to the Prospectus only in the jurisdictions where they may be lawfully offered for sale and therein only by persons permitted to sell such securities. No securities regulatory authority has expressed an opinion about these securities and it is an offence to claim otherwise.

These securities have not been and will not be registered under the United States Securities Act of 1933, as amended and may not be offered, sold or delivered within the United States of America and its territories and possessions or to, or for the account or benefit of, United States persons except in certain transactions exempt from the registration requirements of such Act.

PRICING SUPPLEMENT NO. 2 DATED JANUARY 19, 2010

(to short form base shelf prospectus dated July 27, 2009)

HYDRO ONE INC.
SERIES 19 MEDIUM-TERM NOTES (ADDITIONAL ISSUE)
(unsecured)

ISIN No. CA 44810ZAZ32
CUSIP No. 44810ZAZ3

PRINCIPAL AMOUNT: $500,000,000.00
(five hundred million dollars)

DENOMINATIONS (if other than Cdn dollars or Cdn. dollar denominations of Cdn. $1,000): N/A

ISSUE PRICE: $100.43 per $100.00 principal amount

ACCRUED INTEREST: $2,744,109.59 to be paid to the Company on the settlement of the Notes

AGENTS' COMPENSATION: $0.30 per $100.00 principal amount

NET PROCEEDS TO HYDRO ONE INC. (the "Company") EXCLUDING ACCRUED INTEREST: $500,650,000.00

SPECIFIED CURRENCY:
Canadian Dollars
[●] Yes
[ ] No
Foreign Currency:
Exchange Rate Agent:

ISSUE DATE: January 22, 2010

STATED MATURITY: November 19, 2014

INTEREST RATE: 3.13%

OFFERING YIELD: 3.033%

INTEREST PAYMENT DATE(S):

Equal semi-annual payments on each November 19 and May 19, commencing May 19, 2010.

RECORD DATE(S): The second Business Day prior to such Interest Payment Date

PAYMENT OF PRINCIPAL AND ANY PREMIUM AND INTEREST:
[●] Canadian Dollars
[ ] Specified Currency

DAY COUNT CONVENTION:
[ ] 30/360 for the period
from to
[ ] Actual /360 for the period
from to
[●] Actual/Actual for the period
from November 19, 2009 to November 19, 2014
[ ] Other

OTHER PROVISIONS: See "Redemption" below.

ADDENDUM ATTACHED:
[ ] Yes
[●] No

REDEMPTION: Under the Trust Indenture, as supplemented by the Eighteenth Supplemental Trust Indenture dated as of November 19, 2009, the Notes may be redeemed in whole or in part at the option of the Company at any time, upon not less than 15 days and not more than 60 days notice to the holders of the Notes to be redeemed, and upon deposit with the Trustee, on the date fixed for redemption, of the Redemption Price.

"Redemption Price" means, with respect to a Note to be redeemed, the greater of (i) the Series 19 Note Canada Yield Price and (ii) par, together in each case with accrued and unpaid interest to the date fixed for redemption.

"Government of Canada Yield" on any date means the yield to maturity on such date, compounded semi-annually and calculated in accordance with generally accepted Canadian financial practice, which a non-callable Government of Canada bond would carry if issued in dollars in Canada, at 100% of its principal amount on such date with a term to maturity equal to, or if no Government of Canada bond having an equal term to maturity exists, as close as possible to, the remaining term to maturity (calculated from the redemption date) of, in the case of the Series 19 Notes, the Series 19 Notes, such yield to maturity being the average of the yields provided by two Canadian investment dealers specified by the Company.

"Series 19 Note Canada Yield Price" means a price equal to the price of the Series 19 Notes calculated to provide a yield to maturity, compounded semi-annually and calculated in accordance with generally accepted Canadian financial practice, equal to the Government of Canada Yield calculated at 10:00 a.m. (Toronto time) on the Business Day preceding the day on which the Company gives notice of redemption pursuant to section 5.3 of the Trust Indenture, plus 0.13%.

Terms used in this Pricing Supplement and not defined herein have the meaning given to such terms in the short form base shelf prospectus of the Company dated July 27, 2009.

RATINGS: The Notes will be rated A+ by Standard & Poor's Rating Services, A (high) by DBRS Limited and Aa3 by Moody's Investors Services, Inc.

AGENTS: TD Securities Inc., CIBC World Markets Inc., RBC Dominion Securities Inc., BMO Nesbitt Burns Inc., National Bank Financial Inc., Scotia Capital Inc., Casgrain & Company Limited, HSBC Securities (Canada) Inc. and Laurentian Bank Securities Inc.

FORM:
( ) Fully Registered
(●) Book Entry Only

METHOD OF DISTRIBUTION:
(●) Agency
( ) Principal for Resale
( ) Direct

DOCUMENTS INCORPORATED BY REFERENCE

The following documents (some of which are not specifically listed in the Prospectus or any amendment or supplement thereto) which have been filed by the Company with the various securities commissions or similar authorities in all of the provinces of Canada, are specifically incorporated by reference in and form an integral part of the Prospectus, as amended or supplemented:

(a) the Company's renewal annual information form dated March 31, 2009;

(b) the Company's comparative audited consolidated financial statements, and the notes thereto, as at and for the fiscal years ended December 31, 2008 and December 31, 2007, together with the report of the auditors dated February 11, 2009 on the financial statements as at and for the year ended December 31, 2008;

(c) management's discussion and analysis of the Company's financial results for the year ended December 31, 2008;

(d) the Company's comparative unaudited consolidated financial statements, and the notes thereto, as at September 30, 2009 and for the three and nine months ended September 30, 2009 and September 30, 2008, together with management's discussion and analysis of the Company's financial results for those periods; and

(e) the Company's comparative audited consolidated financial statements, and the notes thereto, as at and for the fiscal years ended December 31, 2007 and December 31, 2006, together with the report of the auditors thereon dated February 13, 2008.

This pricing supplement, together with the short form base shelf prospectus dated July 27, 2009, as amended or supplemented, and each document incorporated by reference into the short form base shelf prospectus (collectively, the "Prospectus") constitutes a public offering of these securities pursuant to the Prospectus only in the jurisdictions where they may be lawfully offered for sale and therein only by persons permitted to sell such securities. No securities regulatory authority has expressed an opinion about these securities and it is an offence to claim otherwise.

These securities have not been and will not be registered under the United States Securities Act of 1933, as amended and may not be offered, sold or delivered within the United States of America and its territories and possessions or to, or for the account or benefit of, United States persons except in certain transactions exempt from the registration requirements of such Act.

PRICING SUPPLEMENT NO. 3 DATED MARCH 10, 2010

(to short form base shelf prospectus dated July 27, 2009, as amended by amendment no. 1 dated March 2, 2010)

HYDRO ONE INC.
SERIES 18 MEDIUM-TERM NOTES (ADDITIONAL ISSUE)
(unsecured)

ISIN No. CA 44810ZAY66
CUSIP No. 44810ZAY6

PRINCIPAL AMOUNT: $200,000,000.00
(two hundred million dollars)

DENOMINATIONS (if other than Cdn dollars or Cdn. dollar denominations of Cdn. $1,000): N/A

ISSUE PRICE: $101.088 per $100.00 principal amount

ACCRUED INTEREST: $1,744,767.12 to be paid to the Company on the settlement of the Notes

AGENTS' COMPENSATION: $0.50 per $100.00 principal amount

NET PROCEEDS TO HYDRO ONE INC. (the "Company") EXCLUDING ACCRUED INTEREST: $201,176,000.00

SPECIFIED CURRENCY:
Canadian Dollars
[●] Yes
[ ] No
Foreign Currency:
Exchange Rate Agent:

ISSUE DATE: March 15, 2010

STATED MATURITY: July 16, 2040

INTEREST RATE: 5.490%

OFFERING YIELD: 5.416%

INTEREST PAYMENT DATE(S):

Equal semi-annual payments on each July 16 and January 16, commencing July 16, 2010.

PAYMENT OF PRINCIPAL AND ANY PREMIUM AND INTEREST:
[●] Canadian Dollars
[ ] Specified Currency

RECORD DATE(S): The second Business Day prior to such Interest Payment Date

DAY COUNT CONVENTION:
[ ] 30/360 for the period
from to
[ ] Actual /360 for the period
from to
[●] Actual/Actual for the period
from July 16, 2009 to July 16, 2040
[ ] Other

OTHER PROVISIONS: See “Redemption” below.

ADDENDUM ATTACHED:
[ ] Yes
[●] No

REDEMPTION: Under the Trust Indenture, as supplemented by the Seventeenth Supplemental Trust Indenture dated as of July 16, 2009, the Notes may be redeemed in whole or in part at the option of the Company at any time, upon not less than 15 days and not more than 60 days notice to the holders of the Notes to be redeemed, and upon deposit with the Trustee, on the date fixed for redemption, of the Redemption Price.

“Redemption Price” means, with respect to a Note to be redeemed, the greater of (i) the Series 18 Note Canada Yield Price and (ii) par, together in each case with accrued and unpaid interest to the date fixed for redemption.

“Government of Canada Yield” on any date means the yield to maturity on such date, compounded semi-annually and calculated in accordance with generally accepted Canadian financial practice, which a non-callable Government of Canada bond would carry if issued in dollars in Canada, at 100% of its principal amount on such date with a term to maturity equal to, or if no Government of Canada bond having an equal term to maturity exists, as close as possible to, the remaining term to maturity (calculated from the redemption date) of, in the case of the Series 18 Notes, the Series 18 Notes, such yield to maturity being the average of the yields provided by two Canadian investment dealers specified by the Company.

“Series 18 Note Canada Yield Price” means a price equal to the price of the Series 18 Notes calculated to provide a yield to maturity, compounded semi-annually and calculated in accordance with generally accepted Canadian financial practice, equal to the Government of Canada Yield calculated at 10:00 a.m. (Toronto time) on the Business Day preceding the day on which the Company gives notice of redemption pursuant to section 5.3 of the Trust Indenture, plus 0.405%.

Terms used in this Pricing Supplement and not defined herein have the meaning given to such terms in the short form base shelf prospectus of the Company dated July 27, 2009, as amended by amendment no. 1 dated March 2, 2010.

RATINGS: The Notes will be rated A+ by Standard & Poor’s Rating Services, A (high) by DBRS Limited and Aa3 by Moody’s Investors Services, Inc.

AGENTS: National Bank Financial Inc., RBC Dominion Securities Inc., BMO Nesbitt Burns Inc., CIBC World Markets Inc., Merrill Lynch Canada Inc., Scotia Capital Inc., TD Securities Inc., Casgrain & Company Limited, Desjardins Securities Inc., HSBC Securities (Canada) Inc. and Laurentian Bank Securities Inc.

FORM:
( ) Fully Registered
(●) Book Entry Only

METHOD OF DISTRIBUTION:
(●) Agency
( ) Principal for Resale
( ) Direct

DOCUMENTS INCORPORATED BY REFERENCE

The following documents (some of which are not specifically listed in the Prospectus or any amendment or supplement thereto) which have been filed by the Company with the various securities commissions or similar authorities in all of the provinces of Canada, are specifically incorporated by reference in and form an integral part of the Prospectus, as amended or supplemented:

(a) the Company’s renewal annual information form dated March 31, 2009;

(b) the Company's comparative audited consolidated financial statements, and the notes thereto, as at and for the fiscal years ended December 31, 2009 and December 31, 2008, together with the report of the auditors thereon dated February 11, 2010; and

(c) management's discussion and analysis of the Company's financial results for the year ended December 31, 2009.

This pricing supplement, together with the short form base shelf prospectus dated July 27, 2009, as amended or supplemented, and each document incorporated by reference into the short form base shelf prospectus (collectively, the "Prospectus") constitutes a public offering of these securities pursuant to the Prospectus only in the jurisdictions where they may be lawfully offered for sale and therein only by persons permitted to sell such securities. No securities regulatory authority has expressed an opinion about these securities and it is an offence to claim otherwise.

These securities have not been and will not be registered under the United States Securities Act of 1933, as amended and may not be offered, sold or delivered within the United States of America and its territories and possessions or to, or for the account or benefit of, United States persons except in certain transactions exempt from the registration requirements of such Act.

PRICING SUPPLEMENT NO. 4 DATED MARCH 10, 2010

(to short form base shelf prospectus dated July 27, 2009, as amended by amendment no. 1 dated March 2, 2010)

HYDRO ONE INC.
SERIES 20 MEDIUM-TERM NOTES
(unsecured)

ISIN No. CA 44810ZBA71
CUSIP No. 44810ZBA7

PRINCIPAL AMOUNT: $300,000,000.00 (three hundred million dollars)

DENOMINATIONS (if other than Cdn dollars or Cdn. dollar denominations of Cdn. $1,000): N/A

ISSUE PRICE: $99.957 per $100.00 principal amount

AGENTS' COMPENSATION: $0.40 per $100.00 principal amount

NET PROCEEDS TO HYDRO ONE INC. (the "Company"): $298,671,000.00

SPECIFIED CURRENCY:
Canadian Dollars
[●] Yes
[ ] No
Foreign Currency:
Exchange Rate Agent:

ORIGINAL ISSUE DATE: March 15, 2010

STATED MATURITY: June 1, 2020

INTEREST RATE: 4.400%

OFFERING YIELD: 4.406%

INTEREST PAYMENT DATE(S):

Each June 1 and December 1, commencing June 1, 2010. Payment of interest on June 1, 2010 will be in an amount equal to $9.402739726 per $1,000 principal amount (short first coupon) and interest payments will be in equal semi-annual amounts on each Interest Payment Date thereafter.

PAYMENT OF PRINCIPAL AND ANY PREMIUM AND INTEREST:
[●] Canadian Dollars
[ ] Specified Currency

RECORD DATE(S): The second Business Day prior to such Interest Payment Date

DAY COUNT CONVENTION:
[ ] 30/360 for the period
from to
[ ] Actual /360 for the period
from to
[●] Actual/Actual for the period
from March 15, 2010 to June 1, 2020
[ ] Other

OTHER PROVISIONS: See "Redemption" below.

ADDENDUM ATTACHED:
[ ] Yes
[●] No

REDEMPTION: Under the Trust Indenture, as supplemented by the Nineteenth Supplemental Trust Indenture to be dated as of March 15, 2010, the Notes may be redeemed in whole or in part at the option of the Company at any time, upon not less than 15 days and not more than 60 days notice to the holders of the Notes to be redeemed, and upon deposit with the Trustee, on the date fixed for redemption, of the Redemption Price.

"Redemption Price" means, with respect to a Note to be redeemed, the greater of (i) the Series 20 Note Canada Yield Price and (ii) par, together in each case with accrued and unpaid interest to the date fixed for redemption.

"Government of Canada Yield" on any date means the yield to maturity on such date, compounded semi-annually and calculated in accordance with generally accepted Canadian financial practice, which a non-callable Government of Canada bond would carry if issued in dollars in Canada, at 100% of its principal amount on such date with a term to maturity equal to, or if no Government of Canada bond having an equal term to maturity exists, as close as possible to, the remaining term to maturity (calculated from the redemption date) of, in the case of the Series 20 Notes, the Series 20 Notes, such yield to maturity being the average of the yields provided by two Canadian investment dealers specified by the Company.

"Series 20 Note Canada Yield Price" means a price equal to the price of the Series 20 Notes calculated to provide a yield to maturity, compounded semi-annually and calculated in accordance with generally accepted Canadian financial practice, equal to the Government of Canada Yield calculated at 10:00 a.m. (Toronto time) on the Business Day preceding the day on which the Company gives notice of redemption pursuant to section 5.3 of the Trust Indenture, plus 0.18%.

Terms used in this Pricing Supplement and not defined herein have the meaning given to such terms in the short form base shelf prospectus of the Company dated July 27, 2009, as amended by amendment no. 1 dated March 2, 2010.

RATINGS: The Notes will be rated A+ by Standard & Poor's Rating Services, A (high) by DBRS Limited and Aa3 by Moody's Investors Services, Inc.

AGENTS: National Bank Financial Inc., RBC Dominion Securities Inc., BMO Nesbitt Burns Inc., CIBC World Markets Inc., Merrill Lynch Canada Inc., Scotia Capital Inc., TD Securities Inc., Casgrain & Company Limited, Desjardins Securities Inc., HSBC Securities (Canada) Inc. and Laurentian Bank Securities Inc.

FORM:
( ) Fully Registered
(●) Book Entry Only

METHOD OF DISTRIBUTION:
(●) Agency
( ) Principal for Resale
( ) Direct

DOCUMENTS INCORPORATED BY REFERENCE

The following documents (some of which are not specifically listed in the Prospectus or any amendment or supplement thereto) which have been filed by the Company with the various securities commissions or similar authorities in all of the provinces of Canada, are specifically incorporated by reference in and form an integral part of the Prospectus, as amended or supplemented:

(a) the Company's renewal annual information form dated March 31, 2009;

(b) the Company's comparative audited consolidated financial statements, and the notes thereto, as at and for the fiscal years ended December 31, 2009 and December 31, 2008, together with the report of the auditors thereon dated February 11, 2010; and

(c) management's discussion and analysis of the Company's financial results for the year ended December 31, 2009.

This pricing supplement, together with the short form base shelf prospectus dated July 27, 2009, as amended or supplemented, and each document incorporated by reference into the short form base shelf prospectus (collectively, the "Prospectus") constitutes a public offering of these securities pursuant to the Prospectus only in the jurisdictions where they may be lawfully offered for sale and therein only by persons permitted to sell such securities. No securities regulatory authority has expressed an opinion about these securities and it is an offence to claim otherwise.

These securities have not been and will not be registered under the United States Securities Act of 1933, as amended and may not be offered, sold or delivered within the United States of America and its territories and possessions or to, or for the account or benefit of, United States persons except in certain transactions exempt from the registration requirements of such Act.

PRICING SUPPLEMENT NO. 6 DATED SEPTEMBER 8, 2010

(to short form base shelf prospectus dated July 27, 2009, as amended by amendment no. 1 dated March 2, 2010)

HYDRO ONE INC.
SERIES 21 MEDIUM-TERM NOTES
(unsecured)

ISIN No. CA 44810ZBB54
CUSIP No. 44810ZBB5

PRINCIPAL AMOUNT: $250,000,000.00
(two hundred and fifty million dollars)

DENOMINATIONS (if other than Cdn dollars or Cdn. dollar denominations of Cdn. $1,000): N/A

ISSUE PRICE: $99.991 per $100.00 principal amount

AGENTS' COMPENSATION: $0.35 per $100.00 principal amount

NET PROCEEDS TO HYDRO ONE INC. (the "Company"): $249,102,500.00

SPECIFIED CURRENCY:
Canadian Dollars
[●] Yes
[ ] No
Foreign Currency:
Exchange Rate Agent:

ORIGINAL ISSUE DATE: September 13, 2010

STATED MATURITY: September 11, 2015

INTEREST RATE: 2.95%

OFFERING YIELD: 2.952%

INTEREST PAYMENT DATE(S):

Each March 11 and September 11, commencing March 11, 2011. Payment of interest on March 11, 2011 will be in an amount equal to $1.44671233 per $100 principal amount (short first coupon) and interest payments will be in equal semi-annual amounts on each Interest Payment Date thereafter.

PAYMENT OF PRINCIPAL AND ANY PREMIUM AND INTEREST:
[●] Canadian Dollars
[ ] Specified Currency

RECORD DATE(S): The second Business Day prior to such Interest Payment Date

DAY COUNT CONVENTION:
[ ] 30/360 for the period from to
[ ] Actual /360 for the period from to
[●] Actual/Actual for the period from September 13, 2010 to September 11, 2015
[ ] Other

OTHER PROVISIONS: See "Redemption" below.

ADDENDUM ATTACHED:
[ ] Yes
[●] No

REDEMPTION: Under the Trust Indenture, as supplemented by the Twentieth Supplemental Trust Indenture to be dated as of September 13, 2010, the Notes may be redeemed in whole or in part at the option of the Company at any time, upon not less than 15 days and not more than 60 days notice to the holders of the Notes to be redeemed, and upon deposit with the Trustee, on the date fixed for redemption, of the Redemption Price.

"Redemption Price" means, with respect to a Note to be redeemed, the greater of (i) the Series 21 Note Canada Yield Price and (ii) par, together in each case with accrued and unpaid interest to the date fixed for redemption.

"Government of Canada Yield" on any date means the yield to maturity on such date, compounded semi-annually and calculated in accordance with generally accepted Canadian financial practice, which a non-callable Government of Canada bond would carry if issued in dollars in Canada, at 100% of its principal amount on such date with a term to maturity equal to, or if no Government of Canada bond having an equal term to maturity exists, as close as possible to, the remaining term to maturity (calculated from the redemption date) of, in the case of the Series 21 Notes, the Series 21 Notes, such yield to maturity being the average of the yields provided by two Canadian investment dealers specified by the Company.

"Series 21 Note Canada Yield Price" means a price equal to the price of the Series 21 Notes calculated to provide a yield to maturity, compounded semi-annually and calculated in accordance with generally accepted Canadian financial practice, equal to the Government of Canada Yield calculated at 10:00 a.m. (Toronto time) on the Business Day preceding the day on which the Company gives notice of redemption pursuant to section 5.3 of the Trust Indenture, plus 0.20%.

Terms used in this Pricing Supplement and not defined herein have the meaning given to such terms in the short form base shelf prospectus of the Company dated July 27, 2009, as amended by amendment no. 1 dated March 2, 2010.

RATINGS: The Notes will be rated A+ by Standard & Poor's Rating Services, A (high) by DBRS Limited and Aa3 by Moody's Investors Services, Inc.

AGENTS: BMO Nesbitt Burns Inc., CIBC World Markets Inc., Merrill Lynch Canada Inc., National Bank Financial Inc., RBC Dominion Securities Inc., Scotia Capital Inc., TD Securities Inc., Casgrain & Company Limited, Desjardins Securities Inc., HSBC Securities (Canada) Inc. and Laurentian Bank Securities Inc.

FORM:
( ) Fully Registered
(●) Book Entry Only

METHOD OF DISTRIBUTION:
(●) Agency
( ) Principal for Resale
( ) Direct

DOCUMENTS INCORPORATED BY REFERENCE

The following documents (some of which are not specifically listed in the Prospectus or any amendment or supplement thereto) which have been filed by the Company with the various securities commissions or similar authorities in all of the provinces of Canada, are specifically incorporated by reference in and form an integral part of the Prospectus, as amended or supplemented:

(a) the Company's renewal annual information form dated March 31, 2010;

(b) the Company's comparative audited consolidated financial statements, and the notes thereto, as at and for the fiscal years ended December 31, 2009 and December 31, 2008, together with the report of the auditors thereon dated February 11, 2010;

(c) management's discussion and analysis of the Company's financial results for the year ended December 31, 2009; and

(d) the Company's comparative unaudited financial statements, and the notes thereto, as at June 30, 2010 and for the three and six month periods ended June 30, 2010 and 2009, together with management's discussion and analysis of the Company's financial results for those periods.

This pricing supplement, together with the short form base shelf prospectus dated July 27, 2009, as amended or supplemented, and each document incorporated by reference into the short form base shelf prospectus (collectively, the "Prospectus") constitutes a public offering of these securities pursuant to the Prospectus only in the jurisdictions where they may be lawfully offered for sale and therein only by persons permitted to sell such securities. No securities regulatory authority has expressed an opinion about these securities and it is an offence to claim otherwise.

These securities have not been and will not be registered under the United States Securities Act of 1933, as amended and may not be offered, sold or delivered within the United States of America and its territories and possessions or to, or for the account or benefit of, United States persons except in certain transactions exempt from the registration requirements of such Act.

PRICING SUPPLEMENT NO. 5 DATED SEPTEMBER 8, 2010

(to short form base shelf prospectus dated July 27, 2009, as amended by amendment no. 1 dated March 2, 2010)

HYDRO ONE INC.
SERIES 11 MEDIUM-TERM NOTES (ADDITIONAL ISSUE)
(unsecured)

ISIN No. CA 44810ZAR16
CUSIP No. 44810ZAR1

PRINCIPAL AMOUNT: $250,000,000.00
(two hundred and fifty million dollars)

DENOMINATIONS (if other than Cdn dollars or Cdn. dollar denominations of Cdn. $1,000): N/A

ISSUE PRICE: $100.765 per $100.00 principal amount

ACCRUED INTEREST: $5,034,246.58 to be paid to the Company on the settlement of the Notes

AGENTS' COMPENSATION: $0.50 per $100.00 principal amount

NET PROCEEDS TO HYDRO ONE INC. (the "Company") EXCLUDING ACCRUED INTEREST: $250,662,500.00

SPECIFIED CURRENCY:
Canadian Dollars
[●] Yes
[ ] No
Foreign Currency:
Exchange Rate Agent:

ISSUE DATE: September 13, 2010

STATED MATURITY: October 19, 2046

INTEREST RATE: 5.00%

OFFERING YIELD: 4.954%

INTEREST PAYMENT DATE(S):

Equal semi-annual payments on each October 19 and April 19, commencing October 19, 2010.

PAYMENT OF PRINCIPAL AND ANY PREMIUM AND INTEREST:
[●] Canadian Dollars
[ ] Specified Currency

RECORD DATE(S): The second Business Day prior to such Interest Payment Date

DAY COUNT CONVENTION:
[ ] 30/360 for the period
from to
[ ] Actual /360 for the period
from to
[●] Actual/Actual for the period
from October 19, 2006 to October 19, 2046
[ ] Other

OTHER PROVISIONS: See “Redemption” below.

ADDENDUM ATTACHED:
[ ] Yes
[●] No

REDEMPTION: Under the Trust Indenture, as supplemented by the Tenth Supplemental Trust Indenture dated as of October 19, 2006, the Notes may be redeemed in whole or in part at the option of the Company at any time, upon not less than 15 days and not more than 60 days notice to the holders of the Notes to be redeemed, and upon deposit with the Trustee, on the date fixed for redemption, of the Redemption Price.

“Redemption Price” means, with respect to a Note to be redeemed, the greater of (i) the Series 11 Note Canada Yield Price and (ii) par, together in each case with accrued and unpaid interest to the date fixed for redemption.

“Government of Canada Yield” on any date means the yield to maturity on such date, compounded semi-annually and calculated in accordance with generally accepted Canadian financial practice, which a non-callable Government of Canada bond would carry if issued in dollars in Canada, at 100% of its principal amount on such date with a term to maturity equal to, or if no Government of Canada bond having an equal term to maturity exists, as close as possible to, the remaining term to maturity (calculated from the redemption date) of, in the case of the Series 11 Notes, the Series 11 Notes, such yield to maturity being the average of the yields provided by two Canadian investment dealers specified by the Company.

“Series 11 Note Canada Yield Price” means a price equal to the price of the Series 11 Notes calculated to provide a yield to maturity, compounded semi-annually and calculated in accordance with generally accepted Canadian financial practice, equal to the Government of Canada Yield calculated at 10:00 a.m. (Toronto time) on the Business Day preceding the day on which the Company gives notice of redemption pursuant to section 5.3 of the Trust Indenture, plus 0.195%.

Terms used in this Pricing Supplement and not defined herein have the meaning given to such terms in the short form base shelf prospectus of the Company dated July 27, 2009, as amended by amendment no. 1 dated March 2, 2010.

RATINGS: The Notes will be rated A+ by Standard & Poor’s Rating Services, A (high) by DBRS Limited and Aa3 by Moody’s Investors Services, Inc.

AGENTS: BMO Nesbitt Burns Inc., CIBC World Markets Inc., Merrill Lynch Canada Inc., National Bank Financial Inc., RBC Dominion Securities Inc., Scotia Capital Inc., TD Securities Inc., Casgrain & Company Limited, Desjardins Securities Inc., HSBC Securities (Canada) Inc. and Laurentian Bank Securities Inc.

FORM:
( ) Fully Registered
(●) Book Entry Only

METHOD OF DISTRIBUTION:
(●) Agency
( ) Principal for Resale
( ) Direct

DOCUMENTS INCORPORATED BY REFERENCE

The following documents (some of which are not specifically listed in the Prospectus or any amendment or supplement thereto) which have been filed by the Company with the various securities commissions or similar authorities in all of the provinces of Canada, are specifically incorporated by reference in and form an integral part of the Prospectus, as amended or supplemented:

(a) the Company’s renewal annual information form dated March 31, 2010;

(b) the Company's comparative audited consolidated financial statements, and the notes thereto, as at and for the fiscal years ended December 31, 2009 and December 31, 2008, together with the report of the auditors thereon dated February 11, 2010;

(c) management's discussion and analysis of the Company's financial results for the year ended December 31, 2009; and

(d) the Company's comparative unaudited financial statements, and the notes thereto, as at June 30, 2010 and for the three and six month periods ended June 30, 2010 and 2009, together with management's discussion and analysis of the Company's financial results for those periods.

This pricing supplement, together with the short form base shelf prospectus dated July 27, 2009, as amended or supplemented, and each document incorporated by reference into the short form base shelf prospectus (collectively, the "Prospectus") constitutes a public offering of these securities pursuant to the Prospectus only in the jurisdictions where they may be lawfully offered for sale and therein only by persons permitted to sell such securities. No securities regulatory authority has expressed an opinion about these securities and it is an offence to claim otherwise.

These securities have not been and will not be registered under the United States Securities Act of 1933, as amended and may not be offered, sold or delivered within the United States of America and its territories and possessions or to, or for the account or benefit of, United States persons except in certain transactions exempt from the registration requirements of such Act.

PRICING SUPPLEMENT NO. 7 DATED JANUARY 14, 2011

(to short form base shelf prospectus dated July 27, 2009, as amended by amendment no. 1 dated March 2, 2010)

HYDRO ONE INC.
SERIES 21 MEDIUM-TERM NOTES (ADDITIONAL ISSUE)
(unsecured)

ISIN No. CA 44810ZBB54
CUSIP No. 44810ZBB5

PRINCIPAL AMOUNT: $250,000,000.00
(two hundred and fifty million dollars)

DENOMINATIONS (if other than Cdn dollars or Cdn. dollar denominations of Cdn. $1,000): N/A

ISSUE PRICE: $99.581 per $100.00 principal amount

ACCRUED INTEREST: $2,586,301.37 to be paid to the Company on the settlement of the Notes

AGENTS' COMPENSATION: $0.30 per $100.00 principal amount

NET PROCEEDS TO HYDRO ONE INC. (the "Company") EXCLUDING ACCRUED INTEREST: $248,202,500.00

SPECIFIED CURRENCY:
Canadian Dollars
[●] Yes
[ ] No
Foreign Currency:
Exchange Rate Agent:

ISSUE DATE: January 19, 2011

STATED MATURITY: September 11, 2015

INTEREST RATE: 2.95%

OFFERING YIELD: 3.047%

INTEREST PAYMENT DATE(S):

Each March 11 and September 11, commencing March 11, 2011. Payment of interest on March 11, 2011 will be in an amount equal to $1.44671233 per $100 principal amount (short first coupon) and interest payments will be in equal semi-annual amounts on each Interest Payment Date thereafter.

PAYMENT OF PRINCIPAL AND ANY PREMIUM AND INTEREST:
[●] Canadian Dollars
[ ] Specified Currency

RECORD DATE(S): The second Business Day prior to such Interest Payment Date

DAY COUNT CONVENTION:
[ ] 30/360 for the period
from to
[ ] Actual /360 for the period
from to
[●] Actual/Actual for the period
from September 13, 2010 to September 11, 2015
[ ] Other

OTHER PROVISIONS: See "Redemption" below.

ADDENDUM ATTACHED:
[ ] Yes
[●] No

REDEMPTION: Under the Trust Indenture, as supplemented by the Twentieth Supplemental Trust Indenture dated as of September 13, 2010, the Notes may be redeemed in whole or in part at the option of the Company at any time, upon not less than 15 days and not more than 60 days notice to the holders of the Notes to be redeemed, and upon deposit with the Trustee, on the date fixed for redemption, of the Redemption Price.

"Redemption Price" means, with respect to a Note to be redeemed, the greater of (i) the Series 21 Note Canada Yield Price and (ii) par, together in each case with accrued and unpaid interest to the date fixed for redemption.

"Government of Canada Yield" on any date means the yield to maturity on such date, compounded semi-annually and calculated in accordance with generally accepted Canadian financial practice, which a non-callable Government of Canada bond would carry if issued in dollars in Canada, at 100% of its principal amount on such date with a term to maturity equal to, or if no Government of Canada bond having an equal term to maturity exists, as close as possible to, the remaining term to maturity (calculated from the redemption date) of, in the case of the Series 21 Notes, the Series 21 Notes, such yield to maturity being the average of the yields provided by two Canadian investment dealers specified by the Company.

"Series 21 Note Canada Yield Price" means a price equal to the price of the Series 21 Notes calculated to provide a yield to maturity, compounded semi-annually and calculated in accordance with generally accepted Canadian financial practice, equal to the Government of Canada Yield calculated at 10:00 a.m. (Toronto time) on the Business Day preceding the day on which the Company gives notice of redemption pursuant to section 5.3 of the Trust Indenture, plus 0.20%.

Terms used in this Pricing Supplement and not defined herein have the meaning given to such terms in the short form base shelf prospectus of the Company dated July 27, 2009, as amended by amendment no. 1 dated March 2, 2010.

RATINGS: The Notes will be rated A+ by Standard & Poor's Rating Services, A (high) by DBRS Limited and Aa3 by Moody's Investors Services, Inc.

AGENTS: Merrill Lynch Canada Inc., Scotia Capital Inc., BMO Nesbitt Burns Inc., CIBC World Markets Inc., National Bank Financial Inc., RBC Dominion Securities Inc., TD Securities Inc., Casgrain & Company Limited, Desjardins Securities Inc., HSBC Securities (Canada) Inc. and Laurentian Bank Securities Inc.

FORM:
( ) Fully Registered
(●) Book Entry Only

METHOD OF DISTRIBUTION:
(●) Agency
( ) Principal for Resale
( ) Direct

DOCUMENTS INCORPORATED BY REFERENCE

The following documents (some of which are not specifically listed in the Prospectus or any amendment or supplement thereto) which have been filed by the Company with the various securities commissions or similar authorities in all of the provinces of Canada, are specifically incorporated by reference in and form an integral part of the Prospectus, as amended or supplemented:

(a) the Company's renewal annual information form dated March 31, 2010;

(b) the Company's comparative audited consolidated financial statements, and the notes thereto, as at and for the fiscal years ended December 31, 2009 and December 31, 2008, together with the report of the auditors thereon dated February 11, 2010;

(c) management's discussion and analysis of the Company's financial results for the year ended December 31, 2009; and

(d) the Company's comparative unaudited financial statements, and the notes thereto, as at September 30, 2010 and for the three and nine month periods ended September 30, 2010 and 2009, together with management's discussion and analysis of the Company's financial results for those periods.

This pricing supplement, together with the short form base shelf prospectus dated July 27, 2009, as amended or supplemented, and each document incorporated by reference into the short form base shelf prospectus (collectively, the "Prospectus") constitutes a public offering of these securities pursuant to the Prospectus only in the jurisdictions where they may be lawfully offered for sale and therein only by persons permitted to sell such securities. No securities regulatory authority has expressed an opinion about these securities and it is an offence to claim otherwise.

These securities have not been and will not be registered under the United States Securities Act of 1933, as amended and may not be offered, sold or delivered within the United States of America and its territories and possessions or to, or for the account or benefit of, United States persons except in certain transactions exempt from the registration requirements of such Act.

PRICING SUPPLEMENT NO. 8 DATED JANUARY 19, 2011

(to short form base shelf prospectus dated July 27, 2009, as amended by amendment no. 1 dated March 2, 2010)

HYDRO ONE INC.
SERIES 22 MEDIUM-TERM NOTES
(unsecured)

ISIN No. CA44810ZBC38
CUSIP No. 44810ZBC3

PRINCIPAL AMOUNT: $50,000,000.00 (fifty million dollars)

DENOMINATIONS (if other than Cdn dollars or Cdn. dollar denominations of Cdn. $1,000): N/A

ISSUE PRICE: $100.00 per $100.00 principal amount

AGENTS' COMPENSATION: $0.30 per $100.00 principal amount

NET PROCEEDS TO HYDRO ONE INC. (the "Company"): $49,850,000

SPECIFIED CURRENCY:
Canadian Dollars
[●] Yes
[ ] No
Foreign Currency:
Exchange Rate Agent:

ORIGINAL ISSUE DATE: January 24, 2011

INTEREST RATE: 3 month BA Rate plus 0.40%. See "Interest Rate Basis" below.

STATED MATURITY: July 24, 2015

INTEREST PAYMENT DATES: Quarterly payments in arrears on January 24, April 24, July 24 and October 24 of each year, commencing April 24, 2011, provided that if any such day is not a business day, the applicable Interest Payment Date will be the next business day.

INTEREST RESET DATES: Original Issue Date and each Interest Payment Date thereafter up to and including April 24, 2015, provided that if any such day is not a business day, the applicable Interest Reset Date will be the next business day.

PAYMENT OF PRINCIPAL AND ANY PREMIUM AND INTEREST:
[●] Canadian Dollars
[ ] Specified Currency

RECORD DATE(S): The second Business Day prior to such Interest Payment Date

DAY COUNT CONVENTION:
[ ] 30/360 for the period from to
[ ] Actual /360 for the period from to
[ ] Actual/Actual for the period from to
[●] Actual / 365

OTHER PROVISIONS: See "Interest Rate Basis" below.

ADDENDUM ATTACHED:
[ ] Yes
[●] No

INTEREST RATE BASIS:

Interest will accrue on any Series 22 Notes outstanding during each Series 22 Note Interest Period on the basis of the 3 month BA Rate (as defined below) determined on the Interest Reset Date at the commencement of such Series 22 Note Interest Period, plus 0.40%.

"**3 month BA Rate**" means, with respect to any Interest Reset Date, the rate per annum (based on a year of 365 days) determined by the Company as (a) the average of the bid rate of interest for three month Canadian dollar bankers' acceptances, as expressed on the Reuters CDOR page at 10:00 a.m. (Toronto time) on such Interest Reset Date, if three or more such bid rates appear on such Reuters CDOR page or (b) if fewer than three such bid rates appear on the Reuters CDOR page at any such time, the arithmetic average rounded to the fifth decimal place (with 0.000005 being rounded up) of the bid rate quotations for three month Canadian dollar bankers' acceptances and that is representative of a single transaction in the market at such time, by the principal Toronto office of three of the five largest Schedule I Canadian chartered banks in the Canadian interbank market selected by the Company at approximately 10:00 a.m. (Toronto time) on such Interest Reset Date.

"**Reuters CDOR page**" means the display designated as page "CDOR" on the Reuters Monitor Money Rates Service (or such other page as may replace the CDOR page on that service) for purposes of displaying Canadian dollar bankers' acceptance rates.

"**Series 22 Note Interest Period**" means the period commencing on each Interest Reset Date and ending on the day immediately preceding the next following Interest Payment Date.

RATINGS: The Notes will be rated A+ by Standard & Poor's Rating Services, A (high) by DBRS Limited and Aa3 by Moody's Investors Services, Inc.

AGENTS: Laurentian Bank Securities Inc., BMO Nesbitt Burns Inc., Casgrain & Company Limited, CIBC World Markets Inc., Desjardins Securities Inc., HSBC Securities (Canada) Inc., Merrill Lynch Canada Inc., National Bank Financial Inc., RBC Dominion Securities Inc., Scotia Capital Inc. and TD Securities Inc.

FORM:
( ) Fully Registered
(●) Book Entry Only

METHOD OF DISTRIBUTION:
(●) Agency
( ) Principal for Resale
( ) Direct

DOCUMENTS INCORPORATED BY REFERENCE

The following documents (some of which are not specifically listed in the Prospectus or any amendment or supplement thereto) which have been filed by the Company with the various securities commissions or similar authorities in all of the provinces of Canada, are specifically incorporated by reference in and form an integral part of the Prospectus, as amended or supplemented:

(a) the Company's renewal annual information form dated March 31, 2010;

(b) the Company's comparative audited consolidated financial statements, and the notes thereto, as at and for the fiscal years ended December 31, 2009 and December 31, 2008, together with the report of the auditors thereon dated February 11, 2010;

(c) management's discussion and analysis of the Company's financial results for the year ended December 31, 2009; and

(d) the Company's comparative unaudited financial statements, and the notes thereto, as at September 30, 2010 and for the three and nine month periods ended September 30, 2010 and 2009, together with management's discussion and analysis of the Company's financial results for those periods.

This pricing supplement, together with the short form base shelf prospectus dated August 23, 2011, as amended or supplemented, and each document incorporated by reference into the short form base shelf prospectus (collectively, the "Prospectus") constitutes a public offering of these securities pursuant to the Prospectus only in the jurisdictions where they may be lawfully offered for sale and therein only by persons permitted to sell such securities. No securities regulatory authority has expressed an opinion about these securities and it is an offence to claim otherwise.

These securities have not been and will not be registered under the United States Securities Act of 1933, as amended and may not be offered, sold or delivered within the United States of America and its territories and possessions or to, or for the account or benefit of, United States persons except in certain transactions exempt from the registration requirements of such Act.

PRICING SUPPLEMENT NO. 1 DATED SEPTEMBER 21, 2011

(to short form base shelf prospectus dated August 23, 2011)

HYDRO ONE INC.
SERIES 23 MEDIUM-TERM NOTES
(unsecured)

ISIN No. CA 44810ZBD11
CUSIP No. 44810ZBD1

PRINCIPAL AMOUNT: $300,000,000.00 (three hundred million dollars)

DENOMINATIONS (if other than Cdn. dollars or Cdn. dollar denominations of Cdn. $1,000): N/A

ISSUE PRICE: $99.901 per $100.00 principal amount

AGENTS' COMPENSATION: $0.50 per $100.00 principal amount

NET PROCEEDS TO HYDRO ONE INC. (the "Company"): $298,203,000.00

SPECIFIED CURRENCY:
Canadian Dollars
[●] Yes
[ ] No
Foreign Currency:
Exchange Rate Agent:

ISSUE DATE: September 26, 2011

STATED MATURITY: September 26, 2041

INTEREST RATE: 4.39%

OFFERING YIELD: 4.396%

INTEREST PAYMENT DATE(S):

Equal semi-annual payments on each March 26 and September 26, commencing March 26, 2012

PAYMENT OF PRINCIPAL AND ANY PREMIUM AND INTEREST:
[●] Canadian Dollars
[ ] Specified Currency

RECORD DATE(S): The second Business Day prior to such Interest Payment Date

DAY COUNT CONVENTION:
[ ] 30/360 for the period
from to
[ ] Actual /360 for the period
from to
[●] Actual/Actual for the period
from September 26, 2011 to September 26, 2041
[ ] Other

OTHER PROVISIONS: See “Redemption” below.

ADDENDUM ATTACHED:
[ ] Yes
[●] No

REDEMPTION: Under the Trust Indenture, as supplemented by the Twenty-Third Supplemental Trust Indenture to be dated as of September 26, 2011, the Notes may be redeemed in whole or in part at the option of the Company at any time, upon not less than 15 days and not more than 60 days notice to the holders of the Notes to be redeemed, and upon deposit with the Trustee, on the date fixed for redemption, of the Redemption Price.

“Redemption Price” means, with respect to a Note to be redeemed, the greater of (i) the Series 23 Note Canada Yield Price and (ii) par, together in each case with accrued and unpaid interest to the date fixed for redemption.

“Government of Canada Yield” on any date means the yield to maturity on such date, compounded semi-annually and calculated in accordance with generally accepted Canadian financial practice, which a non-callable Government of Canada bond would carry if issued in dollars in Canada, at 100% of its principal amount on such date with a term to maturity equal to, or if no Government of Canada bond having an equal term to maturity exists, as close as possible to, the remaining term to maturity (calculated from the redemption date) of, in the case of the Series 23 Notes, the Series 23 Notes, such yield to maturity being the average of the yields provided by two Canadian investment dealers specified by the Company.

“Series 23 Note Canada Yield Price” means a price equal to the price of the Series 23 Notes calculated to provide a yield to maturity, compounded semi-annually and calculated in accordance with generally accepted Canadian financial practice, equal to the Government of Canada Yield calculated at 10:00 a.m. (Toronto time) on the Business Day preceding the day on which the Company gives notice of redemption pursuant to section 5.3 of the Trust Indenture, plus 0.385%.

Terms used in this Pricing Supplement and not defined herein have the meaning given to such terms in the short form base shelf prospectus of the Company dated August 23, 2011.

RATINGS: The Notes will be rated A+ by Standard & Poor’s Rating Services, A (high) by DBRS Limited and Aa3 by Moody’s Investors Services, Inc.

AGENTS: Scotia Capital Inc., TD Securities Inc., Merrill Lynch Canada Inc., BMO Nesbitt Burns Inc., CIBC World Markets Inc., National Bank Financial Inc., RBC Dominion Securities Inc., Casgrain & Company Limited, Desjardins Securities Inc., HSBC Securities (Canada) Inc. and Laurentian Bank Securities Inc.

FORM:
( ) Fully Registered
(●) Book Entry Only

METHOD OF DISTRIBUTION:
(●) Agency
( ) Principal for Resale
( ) Direct

DOCUMENTS INCORPORATED BY REFERENCE

The following documents (some of which are not specifically listed in the Prospectus or any amendment or supplement thereto) which have been filed by the Company with the various securities commissions or similar authorities in all of the provinces of Canada, are specifically incorporated by reference in and form an integral part of the Prospectus, as amended or supplemented:

(a) the Company’s renewal annual information form dated March 31, 2011;

(b) the Company’s comparative audited consolidated financial statements, and the notes thereto, as at and for the fiscal years ended December 31, 2010 and 2009, together with the report of the auditors thereon dated February 10, 2011;

(c) management's discussion and analysis of the Company's financial results for the year ended December 31, 2010; and

(d) the Company's comparative unaudited financial statements, and the notes thereto, as at June 30, 2011 and for the three and six month periods ended June 30, 2011 and June 30, 2010 together with management's discussion and analysis of the Company's financial results for those periods.

This pricing supplement, together with the short form base shelf prospectus dated August 23, 2011, as amended or supplemented, and each document incorporated by reference into the short form base shelf prospectus (collectively, the "Prospectus") constitutes a public offering of these securities pursuant to the Prospectus only in the jurisdictions where they may be lawfully offered for sale and therein only by persons permitted to sell such securities. No securities regulatory authority has expressed an opinion about these securities and it is an offence to claim otherwise.

These securities have not been and will not be registered under the United States Securities Act of 1933, as amended and may not be offered, sold or delivered within the United States of America and its territories and possessions or to, or for the account or benefit of, United States persons except in certain transactions exempt from the registration requirements of such Act.

PRICING SUPPLEMENT NO. 2 DATED DECEMBER 19, 2011

(to short form base shelf prospectus dated August 23, 2011)

HYDRO ONE INC.
SERIES 24 MEDIUM-TERM NOTES
(unsecured)

ISIN No. CA 44810ZBE93
CUSIP No. 44810ZBE9

PRINCIPAL AMOUNT: $100,000,000.00
(one hundred million dollars)

DENOMINATIONS (if other than Cdn. dollars or Cdn. dollar denominations of Cdn. $1,000): N/A

ISSUE PRICE: $99.980 per $100.00 principal amount

AGENTS' COMPENSATION: $0.50 per $100.00 principal amount

NET PROCEEDS TO HYDRO ONE INC. (the "Company"): $99,480,000

SPECIFIED CURRENCY:
Canadian Dollars
[●] Yes
[ ] No
Foreign Currency:
Exchange Rate Agent:

ISSUE DATE: December 22, 2011

STATED MATURITY: December 22, 2051

INTEREST RATE: 4.00%

OFFERING YIELD: 4.001%

INTEREST PAYMENT DATE(S):

Equal semi-annual payments on each June 22 and December 22, commencing June 22, 2012

PAYMENT OF PRINCIPAL AND ANY PREMIUM AND INTEREST:
[●] Canadian Dollars
[ ] Specified Currency

RECORD DATE(S): The second Business Day prior to such Interest Payment Date

DAY COUNT CONVENTION:
[ ] 30/360 for the period
from to
[ ] Actual /360 for the period
from to
[●] Actual/Actual for the period
from December 22, 2011 to December 22, 2051
[ ] Other

OTHER PROVISIONS: See "Redemption" below.

ADDENDUM ATTACHED:
[ ] Yes
[●] No

REDEMPTION: Under the Trust Indenture, as supplemented by the Twenty-Fourth Supplemental Trust Indenture to be dated as of December 22, 2011, the Notes may be redeemed in whole or in part at the option of the Company at any time, upon not less than 15 days and not more than 60 days notice to the holders of the Notes to be redeemed, and upon deposit with the Trustee, on the date fixed for redemption, of the Redemption Price.

"Redemption Price" means, with respect to a Note to be redeemed, the greater of (i) the Series 24 Note Canada Yield Price and (ii) par, together in each case with accrued and unpaid interest to the date fixed for redemption.

"Government of Canada Yield" on any date means the yield to maturity on such date, compounded semi-annually and calculated in accordance with generally accepted Canadian financial practice, which a non-callable Government of Canada bond would carry if issued in dollars in Canada, at 100% of its principal amount on such date with a term to maturity equal to, or if no Government of Canada bond having an equal term to maturity exists, as close as possible to, the remaining term to maturity (calculated from the redemption date) of, in the case of the Series 24 Notes, the Series 24 Notes, such yield to maturity being the average of the yields provided by two Canadian investment dealers specified by the Company.

"Series 24 Note Canada Yield Price" means a price equal to the price of the Series 24 Notes calculated to provide a yield to maturity, compounded semi-annually and calculated in accordance with generally accepted Canadian financial practice, equal to the Government of Canada Yield calculated at 10:00 a.m. (Toronto time) on the Business Day preceding the day on which the Company gives notice of redemption pursuant to section 5.3 of the Trust Indenture, plus 0.39%.

Terms used in this Pricing Supplement and not defined herein have the meaning given to such terms in the short form base shelf prospectus of the Company dated August 23, 2011.

RATINGS: The Notes will be rated A+ by Standard & Poor's Rating Services, A (high) by DBRS Limited and Aa3 by Moody's Investors Services, Inc.

AGENTS: National Bank Financial Inc., BMO Nesbitt Burns Inc., Casgrain & Company Limited, CIBC World Markets Inc., Desjardins Securities Inc., HSBC Securities (Canada) Inc., Laurentian Bank Securities Inc., Merrill Lynch Canada Inc., RBC Dominion Securities Inc., Scotia Capital Inc. and TD Securities Inc.

FORM:
( ) Fully Registered
(●) Book Entry Only

METHOD OF DISTRIBUTION:
(●) Agency
( ) Principal for Resale
( ) Direct

DOCUMENTS INCORPORATED BY REFERENCE

The following documents (some of which are not specifically listed in the Prospectus or any amendment or supplement thereto) which have been filed by the Company with the various securities commissions or similar authorities in all of the provinces of Canada, are specifically incorporated by reference in and form an integral part of the Prospectus, as amended or supplemented:

(a) the Company's renewal annual information form dated March 31, 2011;

(b) the Company's comparative audited consolidated financial statements, and the notes thereto, as at and for the fiscal years ended December 31, 2010 and 2009, together with the report of the auditors thereon dated February 10, 2011;

(c) management's discussion and analysis of the Company's financial results for the year ended December 31, 2010; and

(d) the Company's comparative unaudited financial statements, and the notes thereto, as at September 30, 2011 and for the three and nine month periods ended September 30, 2011 and September 30, 2010 together with management's discussion and analysis of the Company's financial results for those periods.

This pricing supplement, together with the short form base shelf prospectus dated August 23, 2011, as amended or supplemented, and each document incorporated by reference into the short form base shelf prospectus (collectively, the "Prospectus") constitutes a public offering of these securities pursuant to the Prospectus only in the jurisdictions where they may be lawfully offered for sale and therein only by persons permitted to sell such securities. No securities regulatory authority has expressed an opinion about these securities and it is an offence to claim otherwise.

These securities have not been and will not be registered under the United States Securities Act of 1933, as amended and may not be offered, sold or delivered within the United States of America and its territories and possessions or to, or for the account or benefit of, United States persons except in certain transactions exempt from the registration requirements of such Act.

PRICING SUPPLEMENT NO. 3 DATED JANUARY 10, 2012

(to the short form base shelf prospectus dated August 23, 2011)

HYDRO ONE INC.
SERIES 25 MEDIUM-TERM NOTES
(unsecured)

ISIN No. CA 44810ZBF68
CUSIP No. 44810ZBF6

PRINCIPAL AMOUNT: $300,000,000.00 (three hundred million dollars)

DENOMINATIONS (if other than Cdn. dollars or Cdn. dollar denominations of Cdn. $1,000): N/A

ISSUE PRICE: $99.924 per $100.00 principal amount

AGENTS' COMPENSATION: $0.40 per $100.00 principal amount

NET PROCEEDS TO HYDRO ONE INC. (the "Company"): $298,572,000

SPECIFIED CURRENCY:
Canadian Dollars
[●] Yes
[ ] No
Foreign Currency:
Exchange Rate Agent:

ISSUE DATE: January 13, 2012

STATED MATURITY: January 13, 2022

INTEREST RATE: 3.20%

OFFERING YIELD: 3.209%

INTEREST PAYMENT DATE(S):

Equal semi-annual payments on each January 13 and July 13, commencing July 13, 2012

PAYMENT OF PRINCIPAL AND ANY PREMIUM AND INTEREST:
[●] Canadian Dollars
[ ] Specified Currency

RECORD DATE(S): The second Business Day prior to such Interest Payment Date

DAY COUNT CONVENTION:
[ ] 30/360 for the period
from to
[ ] Actual /360 for the period
from to
[●] Actual/Actual for the period
from January 13, 2012 to January 13, 2022
[ ] Other

OTHER PROVISIONS: See "Redemption" below.

ADDENDUM ATTACHED:
[ ] Yes
[●] No

REDEMPTION: Under the Trust Indenture, as supplemented by the Twenty-Fifth Supplemental Trust Indenture to be dated as of January 13, 2012, the Notes may be redeemed in whole or in part at the option of the Company at any time, upon not less than 15 days and not more than 60 days notice to the holders of the Notes to be redeemed, and upon deposit with the Trustee, on the date fixed for redemption, of the Redemption Price.

"Redemption Price" means, with respect to a Note to be redeemed, the greater of (i) the Series 25 Note Canada Yield Price and (ii) par, together in each case with accrued and unpaid interest to the date fixed for redemption.

"Government of Canada Yield" on any date means the yield to maturity on such date, compounded semi-annually and calculated in accordance with generally accepted Canadian financial practice, which a non-callable Government of Canada bond would carry if issued in dollars in Canada, at 100% of its principal amount on such date with a term to maturity equal to, or if no Government of Canada bond having an equal term to maturity exists, as close as possible to, the remaining term to maturity (calculated from the redemption date) of, in the case of the Series 25 Notes, the Series 25 Notes, such yield to maturity being the average of the yields provided by two Canadian investment dealers specified by the Company.

"Series 25 Note Canada Yield Price" means a price equal to the price of the Series 25 Notes calculated to provide a yield to maturity, compounded semi-annually and calculated in accordance with generally accepted Canadian financial practice, equal to the Government of Canada Yield calculated at 10:00 a.m. (Toronto time) on the Business Day preceding the day on which the Company gives notice of redemption pursuant to section 5.3 of the Trust Indenture, plus 0.29%.

Terms used in this Pricing Supplement and not defined herein have the meaning given to such terms in the short form base shelf prospectus of the Company dated August 23, 2011.

RATINGS: The Notes will be rated A+ by Standard & Poor's Rating Services, A (high) by DBRS Limited and Aa3 by Moody's Investors Services, Inc.

AGENTS: Merrill Lynch Canada Inc., TD Securities Inc., BMO Nesbitt Burns Inc., CIBC World Markets Inc., National Bank Financial Inc., RBC Dominion Securities Inc., Scotia Capital Inc., Casgrain & Company Limited, Desjardins Securities Inc., HSBC Securities (Canada) Inc. and Laurentian Bank Securities Inc.

FORM:
( ) Fully Registered
(●) Book Entry Only

METHOD OF DISTRIBUTION:
(●) Agency
( ) Principal for Resale
( ) Direct

DOCUMENTS INCORPORATED BY REFERENCE

The following documents (some of which are not specifically listed in the Prospectus or any amendment or supplement thereto) which have been filed by the Company with the various securities commissions or similar authorities in all of the provinces of Canada, are specifically incorporated by reference in and form an integral part of the Prospectus, as amended or supplemented:

(a) the Company's renewal annual information form dated March 31, 2011;

(b) the Company's comparative audited consolidated financial statements, and the notes thereto, as at and for the fiscal years ended December 31, 2010 and 2009, together with the report of the auditors thereon dated February 10, 2011;

(c) management's discussion and analysis of the Company's financial results for the year ended December 31, 2010; and

(d) the Company's comparative unaudited financial statements, and the notes thereto, as at September 30, 2011 and for the three and nine month periods ended September 30, 2011 and September 30, 2010 together with management's discussion and analysis of the Company's financial results for those periods.

This pricing supplement, together with the short form base shelf prospectus dated August 23, 2011, as amended or supplemented, and each document incorporated by reference into the short form base shelf prospectus (collectively, the "Prospectus") constitutes a public offering of these securities pursuant to the Prospectus only in the jurisdictions where they may be lawfully offered for sale and therein only by persons permitted to sell such securities. No securities regulatory authority has expressed an opinion about these securities and it is an offence to claim otherwise.

These securities have not been and will not be registered under the United States Securities Act of 1933, as amended and may not be offered, sold or delivered within the United States of America and its territories and possessions or to, or for the account or benefit of, United States persons except in certain transactions exempt from the registration requirements of such Act.

PRICING SUPPLEMENT NO. 5 DATED MAY 16, 2012

(to the short form base shelf prospectus dated August 23, 2011)

HYDRO ONE INC.
SERIES 25 MEDIUM-TERM NOTES (ADDITIONAL ISSUE)
(unsecured)

ISIN No. CA 44810ZBF68
CUSIP No. 44810ZBF6

PRINCIPAL AMOUNT: $300,000,000.00 (three hundred million dollars)

DENOMINATIONS (if other than Cdn. dollars or Cdn. dollar denominations of Cdn. $1,000): N/A

ISSUE PRICE: $101.385 per $100.00 principal amount

ACCRUED INTEREST: $3,419,178.08 to be paid to the Company on the settlement of the Notes

AGENTS' COMPENSATION: $0.40 per $100.00 principal amount

NET PROCEEDS TO HYDRO ONE INC. (the "Company") EXCLUDING ACCRUED INTEREST: $302,955,000

SPECIFIED CURRENCY:
Canadian Dollars
[●] Yes
[ ] No
Foreign Currency:
Exchange Rate Agent:

ISSUE DATE: May 22, 2012

STATED MATURITY: January 13, 2022

INTEREST RATE: 3.20%

OFFERING YIELD: 3.033%

INTEREST PAYMENT DATE(S):

Equal semi-annual payments on each January 13 and July 13, commencing July 13, 2012

PAYMENT OF PRINCIPAL AND ANY PREMIUM AND INTEREST:
[●] Canadian Dollars
[ ] Specified Currency

RECORD DATE(S): The second Business Day prior to such Interest Payment Date

DAY COUNT CONVENTION:
[ ] 30/360 for the period
from to
[ ] Actual /360 for the period
from to
[●] Actual/Actual for the period
from January 13, 2012 to January 13, 2022
[ ] Other

OTHER PROVISIONS: See “Redemption” below.

ADDENDUM ATTACHED:
[ ] Yes
[●] No

REDEMPTION: Under the Trust Indenture, as supplemented by the Twenty-Fifth Supplemental Trust Indenture dated as of January 13, 2012, the Notes may be redeemed in whole or in part at the option of the Company at any time, upon not less than 15 days and not more than 60 days notice to the holders of the Notes to be redeemed, and upon deposit with the Trustee, on the date fixed for redemption, of the Redemption Price.

“Redemption Price” means, with respect to a Note to be redeemed, the greater of (i) the Series 25 Note Canada Yield Price and (ii) par, together in each case with accrued and unpaid interest to the date fixed for redemption.

“Government of Canada Yield” on any date means the yield to maturity on such date, compounded semi-annually and calculated in accordance with generally accepted Canadian financial practice, which a non-callable Government of Canada bond would carry if issued in dollars in Canada, at 100% of its principal amount on such date with a term to maturity equal to, or if no Government of Canada bond having an equal term to maturity exists, as close as possible to, the remaining term to maturity (calculated from the redemption date) of, in the case of the Series 25 Notes, the Series 25 Notes, such yield to maturity being the average of the yields provided by two Canadian investment dealers specified by the Company.

“Series 25 Note Canada Yield Price” means a price equal to the price of the Series 25 Notes calculated to provide a yield to maturity, compounded semi-annually and calculated in accordance with generally accepted Canadian financial practice, equal to the Government of Canada Yield calculated at 10:00 a.m. (Toronto time) on the Business Day preceding the day on which the Company gives notice of redemption pursuant to section 5.3 of the Trust Indenture, plus 0.29%.

Terms used in this Pricing Supplement and not defined herein have the meaning given to such terms in the short form base shelf prospectus of the Company dated August 23, 2011.

RATINGS: The Notes will be rated A+ by Standard & Poor’s Rating Services, A (high) by DBRS Limited and A1 by Moody’s Investors Services, Inc. On April 25, 2012, Standard & Poor’s Rating Services revised its outlook on the Company’s long term debt rating to negative from stable. On April 27, 2012, Moody’s Investors Services, Inc. downgraded the Company’s senior unsecured debt rating to A1 from Aa3.

AGENTS: National Bank Financial Inc., RBC Dominion Securities Inc., BMO Nesbitt Burns Inc., CIBC World Markets Inc., Scotia Capital Inc., TD Securities Inc., Desjardins Securities Inc., HSBC Securities (Canada) Inc., Casgrain & Company Limited, Laurentian Bank Securities Inc. and Merrill Lynch Canada Inc.

FORM:
( ) Fully Registered
(●) Book Entry Only

METHOD OF DISTRIBUTION:
(●) Agency
( ) Principal for Resale
( ) Direct

DOCUMENTS INCORPORATED BY REFERENCE

The following documents (some of which are not specifically listed in the Prospectus or any amendment or supplement thereto) which have been filed by the Company with the various securities commissions or similar authorities in all of the provinces of Canada, are specifically incorporated by reference in and form an integral part of the Prospectus, as amended or supplemented:

(a) the Company’s renewal annual information form dated March 23, 2012;

(b) the Company's comparative audited consolidated financial statements, and the notes thereto, as at and for the fiscal years ended December 31, 2011 and 2010, together with the report of the auditors thereon dated February 10, 2012;

(c) management's discussion and analysis of the Company's financial results for the year ended December 31, 2011; and

(d) the Company's comparative unaudited consolidated financial statements, and the notes thereto, as at March 31, 2012 and for the three month periods ended March 31, 2012 and March 31, 2011 together with management's discussion and analysis of the Company's financial results for those periods.

This pricing supplement, together with the short form base shelf prospectus dated August 23, 2011, as amended or supplemented, and each document incorporated by reference into the short form base shelf prospectus (collectively, the "Prospectus") constitutes a public offering of these securities pursuant to the Prospectus only in the jurisdictions where they may be lawfully offered for sale and therein only by persons permitted to sell such securities. No securities regulatory authority has expressed an opinion about these securities and it is an offence to claim otherwise.

These securities have not been and will not be registered under the United States Securities Act of 1933, as amended and may not be offered, sold or delivered within the United States of America and its territories and possessions or to, or for the account or benefit of, United States persons except in certain transactions exempt from the registration requirements of such Act.

PRICING SUPPLEMENT NO. 4 DATED MAY 16, 2012

(to short form base shelf prospectus dated August 23, 2011)

HYDRO ONE INC.
SERIES 24 MEDIUM-TERM NOTES (ADDITIONAL ISSUE)
(unsecured)

ISIN No. CA 44810ZBE93
CUSIP No. 44810ZBE9

PRINCIPAL AMOUNT: $125,000,000.00 (one hundred and twenty-five million dollars)

DENOMINATIONS (if other than Cdn. dollars or Cdn. dollar denominations of Cdn. $1,000): N/A

ISSUE PRICE: $100.017 per $100.00 principal amount

ACCRUED INTEREST: $2,082,191.78 to be paid to the Company on the settlement of the Notes

AGENTS' COMPENSATION: $0.50 per $100.00 principal amount

NET PROCEEDS TO HYDRO ONE INC. (the "Company") EXCLUDING ACCRUED INTEREST: $124,396,250

SPECIFIED CURRENCY:
Canadian Dollars
[●] Yes
[ ] No
Foreign Currency:
Exchange Rate Agent:

ISSUE DATE: May 22, 2012

STATED MATURITY: December 22, 2051

INTEREST RATE: 4.00%

OFFERING YIELD: 3.999%

INTEREST PAYMENT DATE(S):

Equal semi-annual payments on each June 22 and December 22, commencing June 22, 2012

PAYMENT OF PRINCIPAL AND ANY PREMIUM AND INTEREST:
[●] Canadian Dollars
[ ] Specified Currency

RECORD DATE(S): The second Business Day prior to such Interest Payment Date

DAY COUNT CONVENTION:
[ ] 30/360 for the period
from to
[ ] Actual /360 for the period
from to
[●] Actual/Actual for the period
from December 22, 2011 to December 22, 2051
[ ] Other

OTHER PROVISIONS: See "Redemption" below.

ADDENDUM ATTACHED:
[ ] Yes
[●] No

REDEMPTION: Under the Trust Indenture, as supplemented by the Twenty-Fourth Supplemental Trust Indenture dated as of December 22, 2011, the Notes may be redeemed in whole or in part at the option of the Company at any time, upon not less than 15 days and not more than 60 days notice to the holders of the Notes to be redeemed, and upon deposit with the Trustee, on the date fixed for redemption, of the Redemption Price.

"Redemption Price" means, with respect to a Note to be redeemed, the greater of (i) the Series 24 Note Canada Yield Price and (ii) par, together in each case with accrued and unpaid interest to the date fixed for redemption.

"Government of Canada Yield" on any date means the yield to maturity on such date, compounded semi-annually and calculated in accordance with generally accepted Canadian financial practice, which a non-callable Government of Canada bond would carry if issued in dollars in Canada, at 100% of its principal amount on such date with a term to maturity equal to, or if no Government of Canada bond having an equal term to maturity exists, as close as possible to, the remaining term to maturity (calculated from the redemption date) of, in the case of the Series 24 Notes, the Series 24 Notes, such yield to maturity being the average of the yields provided by two Canadian investment dealers specified by the Company.

"Series 24 Note Canada Yield Price" means a price equal to the price of the Series 24 Notes calculated to provide a yield to maturity, compounded semi-annually and calculated in accordance with generally accepted Canadian financial practice, equal to the Government of Canada Yield calculated at 10:00 a.m. (Toronto time) on the Business Day preceding the day on which the Company gives notice of redemption pursuant to section 5.3 of the Trust Indenture, plus 0.39%.

Terms used in this Pricing Supplement and not defined herein have the meaning given to such terms in the short form base shelf prospectus of the Company dated August 23, 2011.

RATINGS: The Notes will be rated A+ by Standard & Poor's Rating Services, A (high) by DBRS Limited and A1 by Moody's Investors Services, Inc. On April 25, 2012, Standard & Poor's Rating Services revised its outlook on the Company's long term debt rating to negative from stable. On April 27, 2012, Moody's Investors Services, Inc. downgraded the Company's senior unsecured debt rating to A1 from Aa3.

AGENTS: National Bank Financial Inc., RBC Dominion Securities Inc., BMO Nesbitt Burns Inc., CIBC World Markets Inc., Scotia Capital Inc., TD Securities Inc., Desjardins Securities Inc., HSBC Securities (Canada) Inc., Casgrain & Company Limited, Laurentian Bank Securities Inc. and Merrill Lynch Canada Inc.

FORM:
( ) Fully Registered
(●) Book Entry Only

METHOD OF DISTRIBUTION:
(●) Agency
( ) Principal for Resale
( ) Direct

DOCUMENTS INCORPORATED BY REFERENCE

The following documents (some of which are not specifically listed in the Prospectus or any amendment or supplement thereto) which have been filed by the Company with the various securities commissions or similar authorities in all of the provinces of Canada, are specifically incorporated by reference in and form an integral part of the Prospectus, as amended or supplemented:

(a) the Company's renewal annual information form dated March 23, 2012;

(b) the Company's comparative audited consolidated financial statements, and the notes thereto, as at and for the fiscal years ended December 31, 2011 and 2010, together with the report of the auditors thereon dated February 10, 2012;

(c) management's discussion and analysis of the Company's financial results for the year ended December 31, 2011; and

(d) the Company's comparative unaudited consolidated financial statements, and the notes thereto, as at March 31, 2012 and for the three month periods ended March 31, 2012 and March 31, 2011 together with management's discussion and analysis of the Company's financial results for those periods.

This pricing supplement, together with the short form base shelf prospectus dated August 23, 2011, as amended or supplemented, and each document incorporated by reference into the short form base shelf prospectus (collectively, the "Prospectus") constitutes a public offering of these securities pursuant to the Prospectus only in the jurisdictions where they may be lawfully offered for sale and therein only by persons permitted to sell such securities. No securities regulatory authority has expressed an opinion about these securities and it is an offence to claim otherwise.

These securities have not been and will not be registered under the United States Securities Act of 1933, as amended and may not be offered, sold or delivered within the United States of America and its territories and possessions or to, or for the account or benefit of, United States persons except in certain transactions exempt from the registration requirements of such Act.

PRICING SUPPLEMENT NO. 6 DATED JULY 26, 2012

(to the short form base shelf prospectus dated August 23, 2011)

HYDRO ONE INC.
SERIES 26 MEDIUM-TERM NOTES
(unsecured)

ISIN No. CA 44810ZBG42
CUSIP No. 44810ZBG4

PRINCIPAL AMOUNT: $75,000,000 (seventy five million dollars)

DENOMINATIONS (if other than Cdn. dollars or Cdn. dollar denominations of Cdn. $1,000): N/A

ISSUE PRICE: $99.978 per $100.00 principal amount

AGENTS' COMPENSATION: $0.50 per $100.00 principal amount

NET PROCEEDS TO HYDRO ONE INC. (the "Company"): $74,608,500

SPECIFIED CURRENCY:
Canadian Dollars
[●] Yes
[ ] No
Foreign Currency:
Exchange Rate Agent:

ISSUE DATE: July 31, 2012

STATED MATURITY: July 31, 2062

INTEREST RATE: 3.79%

OFFERING YIELD: 3.791%

INTEREST PAYMENT DATE(S):

Equal semi-annual payments on each January 31 and July 31, commencing January 31, 2013

PAYMENT OF PRINCIPAL AND ANY PREMIUM AND INTEREST:
[●] Canadian Dollars
[ ] Specified Currency

RECORD DATE(S): The second Business Day prior to such Interest Payment Date

DAY COUNT CONVENTION:
[ ] 30/360 for the period
from to
[ ] Actual /360 for the period
from to
[●] Actual/Actual for the period
from July 31, 2012 to July 31, 2062
[ ] Other

OTHER PROVISIONS: See “Redemption” below.

ADDENDUM ATTACHED:
[ ] Yes
[●] No

REDEMPTION: Under the Trust Indenture, as supplemented by the Twenty-Sixth Supplemental Trust Indenture to be dated as of July 31, 2012, the Notes may be redeemed in whole or in part at the option of the Company at any time, upon not less than 15 days and not more than 60 days notice to the holders of the Notes to be redeemed, and upon deposit with the Trustee, on the date fixed for redemption, of the Redemption Price.

“Redemption Price” means, with respect to a Note to be redeemed, the greater of (i) the Series 26 Note Canada Yield Price and (ii) par, together in each case with accrued and unpaid interest to the date fixed for redemption.

“Government of Canada Yield” on any date means the yield to maturity on such date, compounded semi-annually and calculated in accordance with generally accepted Canadian financial practice, which a non-callable Government of Canada bond would carry if issued in dollars in Canada, at 100% of its principal amount on such date with a term to maturity equal to, or if no Government of Canada bond having an equal term to maturity exists, as close as possible to, the remaining term to maturity (calculated from the redemption date) of, in the case of the Series 26 Notes, the Series 26 Notes, such yield to maturity being the average of the yields provided by two Canadian investment dealers specified by the Company.

“Series 26 Note Canada Yield Price” means a price equal to the price of the Series 26 Notes calculated to provide a yield to maturity, compounded semi-annually and calculated in accordance with generally accepted Canadian financial practice, equal to the Government of Canada Yield calculated at 10:00 a.m. (Toronto time) on the Business Day preceding the day on which the Company gives notice of redemption pursuant to section 5.3 of the Trust Indenture, plus 0.38%.

Terms used in this Pricing Supplement and not defined herein have the meaning given to such terms in the short form base shelf prospectus of the Company dated August 23, 2011.

RATINGS: The Notes will be rated A+ by Standard & Poor’s Rating Services, A (high) by DBRS Limited and A1 by Moody’s Investors Services, Inc. On April 25, 2012, Standard & Poor’s Rating Services revised its outlook on the Company’s long term debt rating to negative from stable. On April 27, 2012, Moody’s Investors Services, Inc. downgraded the Company’s senior unsecured debt rating to A1 from Aa3.

AGENTS: RBC Dominion Securities Inc., BMO Nesbitt Burns Inc., Casgrain & Company Ltd., CIBC World Markets Inc., Desjardins Securities Inc., HSBC Securities (Canada) Inc., Laurentian Bank Securities Inc., Merrill Lynch Canada Inc., National Bank Financial Inc., Scotia Capital Inc. and TD Securities Inc.

FORM:
( ) Fully Registered
(●) Book Entry Only

METHOD OF DISTRIBUTION:
(●) Agency
( ) Principal for Resale
( ) Direct

DOCUMENTS INCORPORATED BY REFERENCE

The following documents (some of which are not specifically listed in the Prospectus or any amendment or supplement thereto) which have been filed by the Company with the various securities commissions or similar authorities in all of the provinces of Canada, are specifically incorporated by reference in and form an integral part of the Prospectus, as amended or supplemented:

(a) the Company’s renewal annual information form dated March 23, 2012;

(b) the Company's comparative audited consolidated financial statements, and the notes thereto, as at and for the fiscal years ended December 31, 2011 and 2010, together with the report of the auditors thereon dated February 10, 2012;

(c) management's discussion and analysis of the Company's financial results for the year ended December 31, 2011; and

(d) the Company's comparative unaudited consolidated financial statements, and the notes thereto, as at March 31, 2012 and for the three month periods ended March 31, 2012 and March 31, 2011 together with management's discussion and analysis of the Company's financial results for those periods.

This pricing supplement, together with the short form base shelf prospectus dated August 23, 2011, as amended or supplemented, and each document incorporated by reference into the short form base shelf prospectus (collectively, the "Prospectus") constitutes a public offering of these securities pursuant to the Prospectus only in the jurisdictions where they may be lawfully offered for sale and therein only by persons permitted to sell such securities. No securities regulatory authority has expressed an opinion about these securities and it is an offence to claim otherwise.

These securities have not been and will not be registered under the United States Securities Act of 1933, as amended and may not be offered, sold or delivered within the United States of America and its territories and possessions or to, or for the account or benefit of, United States persons except in certain transactions exempt from the registration requirements of such Act.

PRICING SUPPLEMENT NO. 7 DATED AUGUST 13, 2012

(to the short form base shelf prospectus dated August 23, 2011)

HYDRO ONE INC.
SERIES 26 MEDIUM-TERM NOTES (ADDITIONAL ISSUE)
(unsecured)

ISIN No. CA 44810ZBG42
CUSIP No. 44810ZBG4

PRINCIPAL AMOUNT: $235,000,000
(two hundred and thirty-five million dollars)

DENOMINATIONS (if other than Cdn. dollars or Cdn. dollar denominations of Cdn. $1,000): N/A

ISSUE PRICE: $99.709 per $100.00 principal amount

ACCRUED INTEREST: $390,421.92 to be paid to the Company on the settlement of the Notes

AGENTS' COMPENSATION: $0.50 per $100.00 principal amount

NET PROCEEDS TO HYDRO ONE INC. (the "Company") EXCLUDING ACCRUED INTEREST: $233,141,150.00

SPECIFIED CURRENCY:
Canadian Dollars
[●] Yes
[ ] No
Foreign Currency:
Exchange Rate Agent:

ISSUE DATE: August 16, 2012

STATED MATURITY: July 31, 2062

INTEREST RATE: 3.79%

OFFERING YIELD: 3.803%

INTEREST PAYMENT DATE(S):

Equal semi-annual payments on each January 31 and July 31, commencing January 31, 2013

PAYMENT OF PRINCIPAL AND ANY PREMIUM AND INTEREST:
[●] Canadian Dollars
[ ] Specified Currency

RECORD DATE(S): The second Business Day prior to such Interest Payment Date

DAY COUNT CONVENTION:
[ ] 30/360 for the period
from to
[ ] Actual /360 for the period
from to
[●] Actual/Actual for the period
from July 31, 2012 to July 31, 2062
[ ] Other

OTHER PROVISIONS: See "Redemption" below.

ADDENDUM ATTACHED:
[ ] Yes
[●] No

REDEMPTION: Under the Trust Indenture, as supplemented by the Twenty-Sixth Supplemental Trust Indenture dated as of July 31, 2012, the Notes may be redeemed in whole or in part at the option of the Company at any time, upon not less than 15 days and not more than 60 days notice to the holders of the Notes to be redeemed, and upon deposit with the Trustee, on the date fixed for redemption, of the Redemption Price.

"Redemption Price" means, with respect to a Note to be redeemed, the greater of (i) the Series 26 Note Canada Yield Price and (ii) par, together in each case with accrued and unpaid interest to the date fixed for redemption.

"Government of Canada Yield" on any date means the yield to maturity on such date, compounded semi-annually and calculated in accordance with generally accepted Canadian financial practice, which a non-callable Government of Canada bond would carry if issued in dollars in Canada, at 100% of its principal amount on such date with a term to maturity equal to, or if no Government of Canada bond having an equal term to maturity exists, as close as possible to, the remaining term to maturity (calculated from the redemption date) of, in the case of the Series 26 Notes, the Series 26 Notes, such yield to maturity being the average of the yields provided by two Canadian investment dealers specified by the Company.

"Series 26 Note Canada Yield Price" means a price equal to the price of the Series 26 Notes calculated to provide a yield to maturity, compounded semi-annually and calculated in accordance with generally accepted Canadian financial practice, equal to the Government of Canada Yield calculated at 10:00 a.m. (Toronto time) on the Business Day preceding the day on which the Company gives notice of redemption pursuant to section 5.3 of the Trust Indenture, plus 0.38%.

Terms used in this Pricing Supplement and not defined herein have the meaning given to such terms in the short form base shelf prospectus of the Company dated August 23, 2011.

RATINGS: The Notes will be rated A+ by Standard & Poor's Rating Services, A (high) by DBRS Limited and A1 by Moody's Investors Services, Inc. On April 25, 2012, Standard & Poor's Rating Services revised its outlook on the Company's long term debt rating to negative from stable. On April 27, 2012, Moody's Investors Services, Inc. downgraded the Company's senior unsecured debt rating to A1 from Aa3.

AGENTS: RBC Dominion Securities Inc., BMO Nesbitt Burns Inc., Casgrain & Company Ltd., CIBC World Markets Inc., Desjardins Securities Inc., HSBC Securities (Canada) Inc., Laurentian Bank Securities Inc., Merrill Lynch Canada Inc., National Bank Financial Inc., Scotia Capital Inc. and TD Securities Inc.

FORM:
( ) Fully Registered
(●) Book Entry Only

METHOD OF DISTRIBUTION:
(●) Agency
( ) Principal for Resale
( ) Direct

DOCUMENTS INCORPORATED BY REFERENCE

The following documents (some of which are not specifically listed in the Prospectus or any amendment or supplement thereto) which have been filed by the Company with the various securities commissions or similar authorities in all of the provinces of Canada, are specifically incorporated by reference in and form an integral part of the Prospectus, as amended or supplemented:

(a) the Company's renewal annual information form dated March 23, 2012;

(b) the Company’s comparative audited consolidated financial statements, and the notes thereto, as at and for the fiscal years ended December 31, 2011 and 2010, together with the report of the auditors thereon dated February 10, 2012;

(c) management’s discussion and analysis of the Company’s financial results for the year ended December 31, 2011; and

(d) the Company’s comparative unaudited consolidated financial statements, and the notes thereto, as at June 30, 2012 and for the three and six month periods ended June 30, 2012 and June 30, 2011, together with management’s discussion and analysis of the Company’s financial results for those periods.

School Energy Coalition (SEC) INTERROGATORY #37 List 1

Issue 18 Is the forecast of long term debt for 2012-2014 appropriate?

Interrogatory

[B1-2-1/p.1]
Please provide all source document that were used in the calculation of the data in Table 4 (eg Global Insight Forecast, documents from MTN dealer group etc).

Response

Please see Attachment 1 used in the preparation of Table 4.

- Pages 1 and 2 provide data obtained from February 2012 Consensus Economics: source used to calculate 10-year bond yields for 2012 and 2013.
- Page 3 provides interest rate data from February 2012 Global Insight: source used to calculate 10-year bond yields for 2014.
- Page 4 provides February interest rates obtained from the Bank of Canada website: source used to calculate Government of Canada 5-year and 30-year spreads over 10-year bond yield.
- Pages 5 and 6 provide data used to average Hydro One's Indicative New Issue Corporate Spread level for February 2012 obtained from members of Hydro One's MTN dealer group.

CANADA

	Average % Change on Previous Calendar Year																		Annual Total
	Gross Domestic Product		Personal Expenditure		Machinery & Equipment Investment		Pre - Tax Corporate Profits		Industrial Production		Consumer Prices		Industrial Product Prices		Average Hourly Earnings		Housing Starts (thousand units)	
	Produit Intérieur Brut		*Dépenses de Consommation des Ménages*		*Investissement Productif*		*Bénéfices des Sociétés avant impôts*		*Production Industrielle*		*Prix à la Consommation*		*Prix des Produits Industriels*		*Rémunération Horaire Moyenne*		*Construction de Logements mises en chantier, milliers*	
Economic Forecasters	2012	2013	2012	2013	2012	2013	2012	2013	2012	2013	2012	2013	2012	2013	2012	2013	2012	2013
Toronto Dominion Bank	2.4	2.4	2.1	2.0	3.3	13.5	2.2	7.7	na	na	1.9	1.8	na	na	na	na	181	172
Royal Bank of Canada	2.3	2.7	2.4	2.2	4.7	6.4	11.9	12.9	na	na	1.7	2.0	na	na	na	na	185	183
JP Morgan	2.2	2.5	2.1	2.6	7.6	7.2	na	na	2.3	2.4	1.8	2.2	3.5	4.0	na	na	na	na
Conf Board of Canada	2.1	2.9	2.4	3.1	7.6	6.5	5.2	7.5	na	na	1.9	2.2	2.2	2.4	na	na	189	192
Informetrica	2.1	2.3	1.9	2.1	5.0	6.0	4.0	8.0	2.3	3.2	2.1	2.0	3.0	3.5	2.3	2.5	175	190
BMO Capital Markets	2.0	2.5	1.7	2.2	5.0	6.0	4.0	4.5	2.0	3.0	2.3	2.1	2.2	2.0	2.2	2.0	187	185
CIBC World Markets	2.0	2.1	2.1	2.2	8.2	9.4	na	na	na	na	1.6	2.0	na	na	na	na	195	181
Desjardins	2.0	2.2	1.8	2.3	6.6	6.9	3.8	8.3	na	na	2.0	1.9	0.3	1.5	1.6	2.7	178	190
Economap	2.0	2.6	1.7	2.3	7.0	5.5	4.0	5.0	2.0	3.3	2.5	2.1	2.7	3.5	2.3	2.5	183	190
EDC Economics	2.0	1.8	1.6	1.4	7.5	9.6	na	na	na	na	2.4	2.0	na	na	na	na	160	140
National Bank Financial	2.0	2.2	1.9	1.9	3.7	5.6	5.8	7.0	na	na	2.2	2.5	na	na	na	na	185	175
IHS Global Insight	2.0	2.6	1.8	2.2	5.8	4.1	2.8	1.2	3.0	4.7	1.8	1.9	1.6	1.8	na	na	197	186
Scotia Economics	1.9	2.2	1.8	2.1	6.6	6.1	3.5	7.0	2.8	3.0	1.9	2.0	na	na	na	na	184	178
Caisse de Depot	1.7	1.8	1.6	1.7	5.3	7.0	4.0	4.5	na	na	1.9	1.8	na	na	na	na	180	175
Merrill Lynch Canada	1.6	2.4	0.8	1.4	-1.4	-4.8	na	na	na	na	2.0	1.8	na	na	na	na	170	185
University of Toronto	1.6	2.7	1.6	2.3	5.7	8.9	5.2	4.7	na	na	1.6	1.9	na	na	na	na	179	180
Capital Economics	1.5	1.0	2.0	1.4	5.0	5.0	na	na	na	na	1.3	1.4	na	na	na	na	160	160
Consensus (Mean)	2.0	2.3	1.8	2.1	5.5	6.4	4.7	6.5	2.4	3.3	1.9	2.0	2.2	2.7	2.1	2.4	180	179
Last Month's Mean	2.0	2.3	1.9	2.2	5.9	6.6	4.8	6.7	2.6	3.2	2.0	2.0	2.2	2.7	2.0	2.4	179	180
3 Months Ago	2.0		2.0		7.4		5.1		2.9		2.0		2.4		2.4		180	
High	2.4	2.9	2.4	3.1	8.2	13.5	11.9	12.9	3.0	4.7	2.5	2.5	3.5	4.0	2.3	2.7	197	192
Low	1.5	1.0	0.8	1.4	-1.4	-4.8	2.2	1.2	2.0	2.4	1.3	1.4	0.3	1.5	1.6	2.0	160	140
Standard Deviation	0.2	0.4	0.4	0.4	2.3	3.6	2.5	2.9	0.4	0.8	0.3	0.2	1.0	1.0	0.3	0.3	10	13
Comparison Forecasts																		
IMF (Sep. '11)	1.9	2.5	1.8								2.1	2.0						
OECD (Nov. '11)	1.9	2.5	1.9	3.0							1.6	1.4						

Government and Background Data

Prime Minister - Mr. Stephen Harper (Conservative). **Government** - The Conservatives hold 167 out of 308 seats in parliament (155 seats are needed for a clear majority). **Next Election** - by May 2015 (general election). **Nominal GDP** - C$1,625bn (2010). **Population** - 33.9mn (mid-year, 2010). **C$/$ Exchange Rate** - 1.030 (average, 2010).

Quarterly Consensus Forecasts

Historical Data and Forecasts (bold italics) From Survey of ***December 12, 2011***

	2011 Q1	2011 Q2	2011 Q3	2011 Q4	2012 Q1	2012 Q2	2012 Q3	2012 Q4	2013 Q1	2013 Q2
Gross Domestic Product	2.8	2.1	2.4	***2.0***	***1.6***	***2.1***	***1.9***	***2.2***	***2.4***	***2.5***
Personal Expenditure	2.1	2.3	1.9	***1.3***	***1.6***	***1.6***	***1.9***	***2.1***	***2.2***	***2.3***
Consumer Prices	2.6	3.4	3.0	***2.8***	***2.4***	***1.9***	***1.9***	***1.9***	***2.0***	***2.0***

Percentage Change (year-on-year).

Historical Data

* *% change on previous year*	2008	2009	2010	2011
Gross Domestic Product*	0.7	-2.8	3.2	2.3 *e*
Personal Expenditure*	3.0	0.4	3.3	1.9 *e*
Machinery & Eqpt Investment*	-0.5	-19.5	11.8	14.3 *e*
Pre - Tax Corporate Profits*	11.0	-33.1	21.2	13.2 *e*
Industrial Production*	-3.1	-9.5	4.9	3.6 *e*
Consumer Prices*	2.4	0.3	1.8	2.9
Industrial Product Prices*	4.3	-3.5	1.0	4.6
Average Hourly Earnings*	3.5	3.0	3.0	2.2 *e*
Housing Starts, '000 units	211	149	190	194
Unemployment Rate, %	6.2	8.3	8.0	7.5
Current Account, C$ bn	5.3	-45.2	-50.9	-49.9 *e*
Federal Govt Budget Balance, fiscal years, C$ bn	-5.8	-55.6	-33.4	-31.2 *e*
3 mth Trsy Bill, % (end yr)	0.9	0.2	1.0	0.8
10 Yr Govt Bond, % (end yr)	2.9	3.6	3.2	1.9

e = consensus estimate based on latest survey

Year Average		Annual Total		Fiscal Years (Apr-Mar)		Rates on Survey Date 0.9%		2.1%	
Unemploy - ment Rate (%)		Current Account (C$ bn)		Federal Govt Budget Balance (C$ bn)		3 month Treasury Bill Rate (%)		10 Year Government Bond Yield (%)	
Taux de Chômage (%)		*Balance Courante (C$ md)*		*Balance Budgétaire (C$ md)*		*Rendement sur les Bons du Trésor de 3 mois %*		*Rendement des Obligat-ions d'État de 10 ans %*	
2012	2013	2012	2013	FY 12-13	FY 13-14	End May'12	End Feb'13	End May'12	End Feb'13
7.6	7.3	na	na	na	na	1.0	1.0	2.0	2.7
7.2	7.0	-28.5	-20.9	na	na	0.9	1.4	2.1	2.4
7.3	7.0	-50.8	-50.7	-31.0	-26.0	na	na	na	na
7.1	6.8	-52.0	-47.0	-24.0	-12.0	0.9	1.3	2.0	2.2
7.4	7.0	-40.0	-35.0	-20.5	-10.0	0.9	1.1	2.2	2.8
7.5	7.2	-46.0	-43.0	-25.0	-18.0	0.9	0.9	2.0	2.4
7.5	7.2	-51.6	-50.7	na	na	0.9	1.0	2.4	2.7
7.4	7.0	-56.3	-47.5	-25.0	-20.0	0.9	1.0	2.0	2.5
7.3	7.0	-49.0	-45.0	-25.0	-18.0	0.9	0.9	2.1	2.5
7.2	7.5	-34.0	-28.0	na	na	na	na	na	na
7.2	6.8	-40.0	-33.0	-25.0	-19.0	0.9	0.9	2.2	2.6
7.3	6.9	-41.1	-35.3	na	na	0.9	1.0	2.3	2.7
7.4	7.2	-49.0	-42.0	-25.5	-16.5	0.9	1.1	2.0	2.2
7.5	7.4	-42.0	-42.0	na	na	0.8	0.8	1.9	2.3
8.0	7.7	-48.5	-46.0	-26.3	-19.1	0.3	2.1	2.0	3.0
7.5	7.1	-44.8	-40.8	na	na	0.9	1.0	2.1	2.8
7.8	8.4	-63.7	-78.7	na	na	0.8	0.4	1.8	1.8
7.4	7.2	-46.1	-42.8	-25.3	-17.6	0.8	1.0	2.1	2.5
7.4	7.1	-45.3	-41.7	-25.0	-17.3				
7.2		-46.6		-21.3					
8.0	8.4	-28.5	-20.9	-20.5	-10.0	1.0	2.1	2.4	3.0
7.1	6.8	-63.7	-78.7	-31.0	-26.0	0.3	0.4	1.8	1.8
0.2	0.4	8.6	12.6	2.7	4.6	0.2	0.4	0.2	0.3
7.7	7.2								
7.3	7.2								

Jobs Downturn Underway

November output-based GDP was unexpectedly disappointing. GDP fell by 0.1% (m-o-m) following flat growth in October, reined in by a 2.1% monthly drop in the energy sector. Oil and gas extraction contracted by 2.5% over the month as a result of maintenance shutdowns of oil refineries. This impacted on industrial production which ended up falling by 0.8% (m-o-m). On the upside, manufacturing recorded a 0.6% jump, boosted by durables spending. Elsewhere, new factory orders during the same month rebounded from a -3.9% (m-o-m) collapse in October to +3.6%, while sales recorded a 2.0% gain. This, coupled with employment in the goods-producing industries increasing in January, suggests a somewhat positive outlook for industrial output as a whole. Perhaps this is due to the fact that the export-oriented sector has strong links with the US economy where a modest recovery is apparent. Despite this, our panel's industrial production forecast for 2012 has faltered this month.

The GDP outlook is also somewhat shaky on the back of the lacklustre GDP report. Despite a relatively positive retail sales release for November, overall jobs growth has started to stall of late and households remain rather leveraged. In the current austere environment, that is worrisome. Low interest rates have helped to support borrowing but bank lending is also tightening, especially in light of the global economic chill. The Euro zone debt crisis remains a concern for exporters while China is also slowing. Even the US recovery is expected to be gradual at best, as opposed to a fully-fledged expansion. Moreover, some speculate that commodity price surges will ease this year. The Bank of Canada left the overnight lending rate at 1% in February and should remain on hold – for now.

Canada Overnight Lending Rate – Feb. 13, 2012 = 1.00%

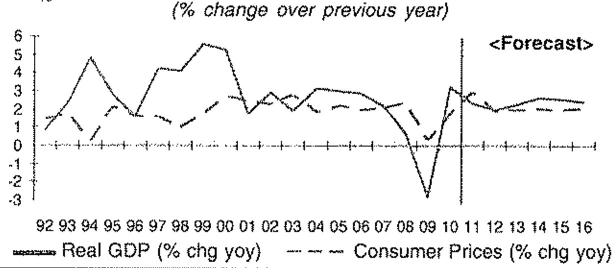
FORECASTS	End Mar. 2012	End June 2012	End Sep. 2012	End Dec. 2012
Consensus **Mean Average:**	1.00%	0.97%	0.92%	0.94%
Mode (most frequent forecast):	1.00%	1.00%	1.00%	1.00%

Direction of Trade – 2010

Major Export Markets (% of Total)		Major Import Suppliers (% of Total)	
United States	74.9	United States	50.4
United Kingdom	4.1	China	11.0
China	3.3	Mexico	5.5
Asia (ex. Japan)	*5.2*	*Asia (ex. Japan)*	*13.9*
Latin America	*3.1*	*Latin America*	*9.3*
Middle East	*1.0*	*Africa*	*2.4*

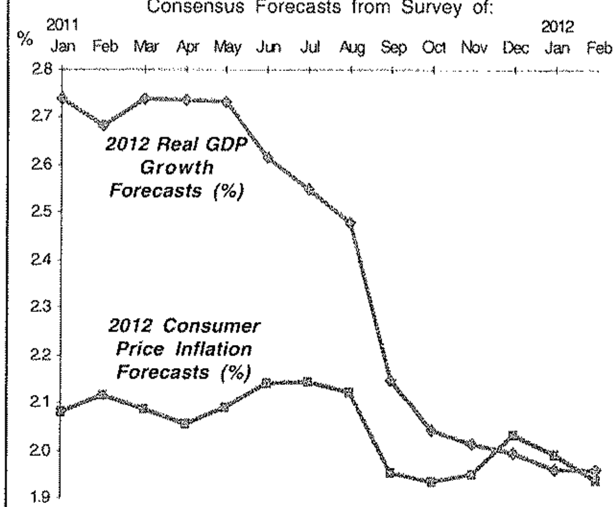
Real Growth and Inflation

(% change over previous year)



GDP Growth and Inflation Forecasts

Consensus Forecasts from Survey of:



FORECAST SUMMARY (February 2012)

	2012 Q1	2012 Q2	2012 Q3	2012 Q4	2011	2012	2013	2014	2015	2016	2017
REAL GDP					(Percent Change)						
U.S.	2.2	2.3	1.6	2.0	1.7	2.1	2.3	3.3	3.2	2.7	2.6
Canada	1.7	2.3	2.5	2.6	2.3	2.0	2.6	2.7	2.7	2.6	2.5
Ontario	0.2	0.5	0.6	0.5	2.1	1.7	2.5	2.6	2.4	2.7	3.0
COST INDICATORS											
GDP DEFLATOR											
U.S.	1.3	0.5	1.5	1.5	2.1	1.2	1.4	1.7	1.8	1.8	1.8
Canada	1.7	1.5	1.7	1.2	3.1	1.8	1.9	2.0	1.9	1.8	1.9
CPI											
U.S.	2.6	1.8	1.6	1.9	3.1	2.0	1.8	1.9	1.9	1.9	1.8
Canada (NSA)	2.0	1.8	1.6	1.8	2.9	1.8	1.9	2.0	2.0	2.0	2.0
Ontario (NSA)	2.5	1.5	1.5	2.4	3.1	2.0	2.1	2.0	2.0	2.0	2.0
INTEREST RATES					(Percent)						
U.S. 3 MONTH LIBOR	0.54	0.49	0.40	0.38	0.34	0.45	0.38	0.39	1.54	3.58	4.25
CDA 3 MONTH B.A.	0.98	0.98	0.99	1.04	1.19	1.00	1.10	2.07	3.25	4.25	4.62
3 MONTH T-BILLS											
U.S.	0.04	0.05	0.06	0.06	0.05	0.05	0.06	0.09	1.31	3.20	3.77
Canada	0.86	0.86	0.87	0.92	0.92	0.88	0.98	1.95	3.13	4.13	4.50
BANK PRIME											
U.S.	3.25	3.25	3.25	3.25	3.25	3.25	3.25	3.25	4.23	6.27	7.00
Canada	3.00	3.00	3.00	3.00	3.00	3.00	3.02	4.02	5.13	6.13	6.62
5 YEAR BONDS											
U.S.	0.89	1.14	1.27	1.36	1.52	1.17	1.48	1.61	2.62	4.15	4.46
Canada	1.77	1.92	2.00	2.08	2.07	1.94	2.31	2.74	3.53	4.55	4.88
10 YEAR BONDS											
U.S.	1.98	2.19	2.31	2.40	2.79	2.22	2.69	2.91	3.54	4.57	4.88
Canada	2.13	2.34	2.46	2.55	2.78	2.37	2.84	3.06	3.69	4.72	5.03
LONG BONDS											
U.S.	3.00	3.16	3.25	3.34	3.91	3.19	3.62	3.84	4.14	5.01	5.27
Canada	2.68	2.88	2.97	3.04	3.29	2.89	3.30	3.48	4.09	5.10	5.40
FOREIGN EXCHANGE					(U.S. Cents per Canadian dollar)						
Canadian Dollar	99.44	99.68	99.20	98.86	101.13	99.29	98.66	98.96	96.72	93.48	90.90

Daily series: 2012-02-01 - 2012-02-29
V39053 = Government of Canada benchmark bond yields - 5 year
V39055 = Government of Canada benchmark bond yields - 10 year
V39056 = Government of Canada benchmark bond yields - long-term

Summary	Date	V39053	Date	V39055	Date	V39056
Low	2/1/2012	1.26	2/1/2012	1.9	2/1/2012	2.52
High	2/21/2012	1.5	2/21/2012	2.09	2/21/2012	2.66
Average	2012-02-01	1.4	2012-02-01	2.02	2012-02-01	2.61

Date	V39053	V39055	10/5 Spread	V39056	30/10 Spread
2/29/2012	1.44	1.98	0.54	2.6	0.62
2/28/2012	1.41	1.98	0.57	2.6	0.62
2/27/2012	1.42	2	0.58	2.62	0.62
2/24/2012	1.43	2.02	0.59	2.64	0.62
2/23/2012	1.47	2.05	0.58	2.64	0.59
2/22/2012	1.48	2.05	0.57	2.64	0.59
2/21/2012	1.5	2.09	0.59	2.66	0.57
2/17/2012	1.47	2.05	0.58	2.64	0.59
2/16/2012	1.38	2.03	0.65	2.61	0.58
2/15/2012	1.37	2.01	0.64	2.59	0.58
2/14/2012	1.38	2.02	0.64	2.6	0.58
2/13/2012	1.41	2.07	0.66	2.64	0.57
2/10/2012	1.41	2.05	0.64	2.62	0.57
2/9/2012	1.44	2.09	0.65	2.64	0.55
2/8/2012	1.41	2.06	0.65	2.64	0.58
2/7/2012	1.38	2.04	0.66	2.62	0.58
2/6/2012	1.33	1.98	0.65	2.57	0.59
2/3/2012	1.35	2.01	0.66	2.61	0.60
2/2/2012	1.29	1.94	0.65	2.55	0.61
2/1/2012	1.26	1.9	0.64	2.52	0.62
	1.40	**2.02**	**0.62**	**2.61**	**0.59**
	1.402	2.021	0.620	2.613	0.592

Indicative Average New Issue Spreads
from Hydro One's Medium Term Note Dealer Group

Date	5 year	10 year	30 year
Feb 6	0.83%	1.09%	1.36%
Feb 7	0.81%	1.06%	1.33%
Feb 21	0.80%	1.06%	1.35%
Feb 27	0.80%	1.05%	1.36%
February 2012 Avg	**0.81%**	**1.06%**	**1.35%**

Feb 6
New Issue Spreads

Date		2 Year	3 year	5 year	7 year	10 year	30 year
Feb 6	RBCDS	60	70	82	92	107	135
Feb 3	Nesbitt	49	62	77	88	104	133
Feb 6	NBF	55	65	80	95	110	135
Feb 6	Scotia		68	84	94	110	138
Feb 6	HSBC		70	87	96	111	134
Feb 6	CIBC	65	70	83	93	105	137
Feb 6	BoAML		64	84	96	108	135
Feb 6	Desjardins						
Feb 6	TD		80	90	100	115	140
	Average	57.3	68.6	83.4	94.3	108.8	135.9

Feb 7
New Issue Spreads

Date		2 Year	3 year	5 year	7 year	10 year	30 year
Feb 7	RBCDS	60	70	82	92	105	135
Feb 10	Nesbitt	49	62	76	87	102	133
Feb 13	NBF	55	65	80	90	105	130
Feb 13	Scotia		65	81	92	108	133
Feb 13	HSBC		75	85	96	111	135
Feb 13	CIBC	62	67	80	90	105	133
Feb 13	BoAML		60	80	93	105	131
Feb 13	Desjardins		58	78	88	100	132
Feb 13	TD		75	85	95	110	135
	Average	56.5	66.3	80.8	91.4	105.7	133.0

Feb 21
New Issue Spreads

Date		2 Year	3 year	5 year	7 year	10 year	30 year
Feb 21	RBCDS	58	68	78	90	102	134
Feb 21	Nesbitt		63	76	88	104	135
Feb 21	NBF	55	65	80	90	105	135
Feb 21	Scotia			81		109	138
Feb 21	HSBC		68	80	95	105	137
Feb 21	CIBC		67	80	90	105	133
Feb 21	BoAML		60	80	93	107	137
Feb 22	Desjardins		62	80	90	105	135
Feb 21	TD		75	85	95	110	135
	Average	56.5	66.0	80.0	91.4	105.8	135.4

Feb 27
New Issue Spreads

Date		2 Year	3 year	5 year	7 year	10 year	30 year
Feb 27	RBCDS	56	66	78	88	100	133
Feb 24	Nesbitt	47	63	75	87	103	135
Feb 27	NBF	55	65	80	90	105	135
Feb 28	Scotia			82		110	138
Feb 27	HSBC		68	80	95	105	137
Feb 27	CIBC		67	80	90	106	135
Feb 27	BoAML		60	80	93	105	137
Feb 27	Desjardins		62	80	90	105	135
Feb 27	TD		75	85	95	110	135
	Average	52.7	65.8	80.0	91.0	105.4	135.6

Ontario Energy Board (Board Staff) INTERROGATORY #77 List 1

Issue 19 **Are the proposed amounts, disposition and continuance of Hydro One's existing Deferral and Variance accounts appropriate?**

Interrogatory

Ref: Exhibit F1/Tab1/Sch1/Table 2 and Exhibit A/Tab9/Sch1/Attachment 3

a) Please complete a continuity schedule for the deferral and variance accounts requested for approval at Exhibit F1/Tab1/Schedule1/Table 2 similar to the "2013 EDDVAR Continuity Schedule" used in cost of service distribution proceedings. The continuity schedule should show balances from December 31, 2009 (i.e. the balance sheet date that was cleared in the most recent rates proceeding) and forward. The schedule should at a minimum display transactions incurred during the year, any adjustments, carrying charges incurred, and Board approved transactions to clear the regulatory accounts. The link to the "2013 EDDVAR Continuity Schedule" is below:

http://www.ontarioenergyboard.ca/OEB/_Documents/2013EDR/2013_EDDVAR_Continuity_Schedule_CoS_v2_20120706.xlsm

b) Please reconcile the continuity schedule to the December 31, 2011 Audited Financial Statements, at Exhibit A/Tab 9/Schedule1/Attachment 3. Please provide an explanation if the continuity schedule differs from the December 31, 2011 Audited Financial Statements.

c) Please provide a statement as to whether Hydro One has made any adjustments to deferral and variance account balances that were previously approved by the Board on a final basis (i.e. balances that were adjusted subsequent to the balance sheet date that were cleared in the most recent rates proceeding). If this is the case, please provide explanations for the nature and amounts of the adjustments and include supporting documentation.

Response

a) Please see the requested continuity schedule attached as Appendix A.

b)

Reconciliation of Regulatory Accounts shown in the EDDVAR to the Regulatory Accounts reported in the year-end 2011 Financial Statements		
	2010	**2011**
	$M's	*$M's*
Exhibit A-9-3: (2011 Transmission Financial Statements):		
Regulatory Assets (as per Note 8)	675	701
Regulatory Liabilities (as per Note 8)	(44)	(54)
Total Regulatory Assets & Liabilities	$631	$647
Exhibit F1-1-1 Table 2:		
Balance of the Regulatory Assets and Liabilities	($18)	($29)
Add: Financial Policy Regulatory Amounts[1]		
Environmental Regulatory Asset	134	100
Future Income Tax Regulatory Asset	522	583
Future Income Tax Regulatory Liability	(7)	(7)
Sub-Total Adjustments	**649**	**676**
Total EDDVAR Continuity Schedule plus Financial Accounting Policy Regulatory Accounts	$631	$647

[1]Financial policy regulatory amounts are not Board-approved deferral or variance accounts. Financial policy regulatory amounts are recorded under GAAP to appropriately reflect the effects of rate regulation on a qualifying entity's financial statements. This is required under both legacy CGAAP and US GAAP. While these amounts do represent differences in timing of recognition between the regulatory treatment and that which would be accorded by a non-rate regulated enterprise, such amounts are not directly recovered or refunded to customers through the mechanism used for deferral and variance accounts.

c) The only adjustment made from previous Board-approved balances was to Market Ready Costs Account. As at December 31, 2011, Hydro One Transmission had recorded an asset balance of approximately $0.8 million in this account. This amount represented unrecovered accrued interest accumulated during the four year disposition period of the original deferred cost. Hydro One determined that it would not seek recovery of this interest amount given the lengthy period that has passed since market opening and the relative materiality of the account balance. As a result, the balance was written off as at December 31, 2011.

Deferral/Variance Account Workform for 2013 Filers

				2010								
Account Descriptions	Account Number	Closing Principal Balance as of Dec-31-09	Closing Interest Amounts as of Dec-31-09	Opening Principal Amounts as of Jan-1-10	Transactions Debit / (Credit) during 2010 excluding interest and adjustments 6	Board-Approved Disposition during 2010	Closing Principal Balance as of Dec-31-10	Opening Interest Amounts as of Jan-1-10	Interest Jan-1 to Dec-31-10	Board-Approved Disposition during 2010	Adjustments during 2010 - other	Closing Interest Amounts as of Dec-31-10
Deferred Export Service Credit Revenue	2405	(11,746,107)	(3,565,813)	(11,746,107)	-	(12,391,489)	645,383	(3,565,813)	(35,589)			(3,601,402)
Excess Export Service Revenue	2405	(4,816,978)	(20,718)	(4,816,978)	(4,286,661)	-	(9,103,639)	(20,718)	(51,769)			(72,487)
External Station Maintenance & E&CS Revenue	2405	(4,385,050)	(3,236)	(4,385,050)	(6,437,136)		(10,822,186)	(3,236)	(53,650)			(56,886)
External Revenue - Secondary Land Use	2405	(3,189,127)	(2,354)	(3,189,127)	(6,122,487)		(9,311,614)	(2,354)	(46,592)			(48,946)
Tax Rate Changes	1592	(8,716,521)	(366,559)	(8,716,521)	(4,324,565)	(9,266,664)	(3,774,422)	(366,559)	(39,968)			(406,527)
Rights Payments	2405	-	-	-	-	-	-	-	-			-
Long Term Project Development Costs	1508	1,931,962	1,980	1,931,962	4,552,221	-	6,484,183	1,980	39,136			41,116
Pension Cost Differential	2405	3,174,463	(61,585)	3,174,463	7,977,416	(133,331)	11,285,210	(61,585)	57,478			(4,107)
Market Ready Costs	1570	3,780,228	1,199,180	3,780,228	-	4,167,840	(387,612)	1,199,180	11,958			1,211,137
OEB Incremental Assessment Costs	1508	(2,627,242)	(140,010)	(2,627,242)	(100,511)	(2,799,996)	72,243	(140,010)	(9,026)			(149,036)
IFRS Incremental Transition Costs	1508	(19,602)	-	(19,602)	229,412	-	209,810	-	939			939
Sub-Total		(26,613,973)	(2,959,116)	(26,613,973)	(8,512,311)	(20,423,640)	(14,702,644)	(2,959,116)	(127,082)	-	-	(3,086,198)

Deferral/Variance Account Workform for 2013 Filers

Account Descriptions	Account Number	2011 Opening Principal Amounts as of Jan-1-11	2011 Transactions Debit / (Credit) during 2011 excluding interest and adjustments 6	2011 Board-Approved Disposition during 2011	2011 Closing Principal Balance as of Dec-31-11	2011 Opening Interest Amounts as of Jan-1-11	2011 Interest Jan-1 to Dec-31-11	2011 Board-Approved Disposition during 2011	2011 Closing Interest Amounts as of Dec-31-11	2012 Principal Adjustments during 2012	2012 Interest Adjustments during 2012	2012 Closing Principal Balances as of Dec 31-11 Adjusted for Dispositions & Adjustments during 2012	2012 Closing Interest Balances as of Dec 31-11 Adjusted for Dispositions & adjustments during 2012
Deferred Export Service Credit Revenue	2405	645,383	(645,383)		-	(3,601,402)	665,862		(2,935,540)			-	(2,935,540)
Excess Export Service Revenue	2405	(9,103,639)	(14,175,455)	(4,816,978)	(18,462,116)	(72,487)	(202,871)	(83,022)	(192,336)			(18,462,116)	(192,336)
External Station Maintenance & E&CS Revenue	2405	(10,822,186)	1,386,255	(4,385,050)	(5,050,881)	(56,886)	(78,165)	(14,950)	(120,102)			(5,050,881)	(120,102)
External Revenue - Secondary Land Use	2405	(9,311,614)	(8,036,104)	(3,189,127)	(14,158,591)	(48,946)	(219,112)	(10,872)	(257,185)			(14,158,591)	(257,185)
Tax Rate Changes	1592	(3,774,422)	-	-	(3,774,422)	(406,527)	(55,484)		(462,011)			(3,774,422)	(462,011)
Rights Payments	2405	-	(1,725,664)	-	(1,725,664)	-	(2,447)		(2,447)			(1,725,664)	(2,447)
Long Term Project Development Costs	1508	6,484,183	-	1,931,962	4,552,221	41,116	82,239	68,037	55,318			4,552,221	55,318
Pension Cost Differential	2405	11,285,210	4,307,499	3,174,462	12,418,247	(4,107)	170,196	(74,464)	240,553			12,418,247	240,553
Market Ready Costs	1570	(387,612)	387,612		0	1,211,137	(394,498)		816,639	-	(816,639)	0	0
OEB Incremental Assessment Costs	1508	72,243	-	-	72,243	(149,036)	1,062		(147,974)	(72,243)	147,974	-	-
IFRS Incremental Transition Costs	1508	209,810	(61,202)	-	148,608	939	3,320		4,258	(148,608)	(4,258)	-	-
Sub-Total		(14,702,644)	(18,562,442)	(7,284,731)	(25,980,354)	(3,086,198)	(29,898)	(115,271)	(3,000,825)	(220,852)	(672,924)	(26,201,206)	(3,673,749)

Deferral/Variance Account Workform for 2013 Filers

		Projected Interest on Dec-31-11 Balances						2.1.7 RRR	
Account Descriptions	Account Number	Projected Interest from Jan 1, 2012 to December 31, 2012 on Dec 31 -11 balance adjusted	Projected Interest from January 1, 2013 to April 30, 2013 on Dec 31 - 11 balance adjusted for	Closing Principal Balances as of Dec 31-12 Adjusted for Dispositions during 2012	Closing Interest Balances as of Dec 31-12 Adjusted during 2012 Disposition	Total Claim	Principal as at Dec 31, 2011 + Projected Interest as at Dec 31, 2012	As of Dec 31-11	Variance RRR vs. 2011 Balance (Principal + Interest)
Deferred Export Service Credit Revenue	2405	-		-	(2,935,540)	(2,935,540)	(2,935,540)	(2,935,540)	0
Excess Export Service Revenue	2405	(271,393)		(18,462,116)	(463,729)	(18,925,845)	(18,925,845)	(18,654,451)	0
External Station Maintenance & E&CS Revenue	2405	(74,248)		(5,050,881)	(194,350)	(5,245,231)	(5,245,231)	(5,170,983)	-
External Revenue - Secondary Land Use	2405	(208,131)		(14,158,591)	(465,317)	(14,623,907)	(14,623,907)	(14,415,776)	0
Tax Rate Changes	1592	(55,484)		(3,774,422)	(517,495)	(4,291,917)	(4,291,917)	(4,236,433)	(0)
Rights Payments	2405	(25,367)		(1,725,664)	(27,814)	(1,753,478)	(1,753,478)	(1,728,111)	(0)
Long Term Project Development Costs	1508	66,918		4,552,221	122,236	4,674,457	4,674,457	4,607,539	(0)
Pension Cost Differential	2405	182,548		12,418,247	423,101	12,841,348	12,841,348	12,658,799	(0)
				-	-	-			
Market Ready Costs	1570	0		0	0	0	0	816,639	(0)
OEB Incremental Assessment Costs	1508	-		-	-	-	-	(75,730)	0
IFRS Incremental Transition Costs	1508	-		-	-	-	-	152,867	0
Sub-Total		(385,158)	-	(26,201,206)	(4,058,907)	(30,260,113)	(30,260,113)	(28,981,180)	(0)

Ontario Energy Board (Board Staff) INTERROGATORY #78 List 1

Issue 19 Are the proposed amounts, disposition and continuance of Hydro One's existing Deferral and Variance accounts appropriate?

Interrogatory

Ref: Exhibit F1/Tab1/Sch1 and Exhibit F1/Tab1/Sch2
At Exhibit F1/Tab 1/Schedule 2, Hydro One stated that it is not seeking continuance of the "Deferred Export Service Credit Revenue" variance account and the "Long Term Project Development Costs" deferral account in this proceeding. At Exhibit F1/Tab1/Schedule1, Hydro One also indicated that the following deferral and variance accounts have a zero balance forecasted as at December 31, 2012:

- Market Ready Costs
- OEB Incremental Assessment Costs
- IFRS Incremental Transition Costs

a) Is Hydro One seeking discontinuance of the following deferral and variance accounts in this proceeding?

    i. Market Ready Costs
    ii. OEB Incremental Assessment Costs
    iii. IFRS Incremental Transition Costs

b) If Hydro One is not seeking discontinuance of these accounts, please provide an explanation, particularly:

    i. Is there no longer a need for these accounts? and
    ii. the balances in these accounts are forecast to be zero as at December 31, 2012.

Response

a)
    i) Yes
    ii) Yes
    iii) Yes

b) N/A

Ontario Energy Board (Board Staff) INTERROGATORY #79 List 1

Issue 19 Are the proposed amounts, disposition and continuance of Hydro One's existing Deferral and Variance accounts appropriate?

Interrogatory

Ref: Exhibit A/Tab3/Sch1 and Exhibit F1/Tab1/Sch2
As per Exhibit A/Tab 3/Schedule 1, Hydro One is proposing to continue the following variance accounts:

i. Impact for Changes in US GAAP variance account
As per Exhibit F1/Tab1/Schedule 2, Hydro One Transmission proposes to record any impacts of changes to US GAAP compared to the basis of those approved in this filing by the OEB as part of 2013 and 2014 Transmission Rates test years.

ii. US GAAP Incremental Transition Costs variance account
As per Exhibit F1/Tab 1/Schedule 2, Hydro One Transmission proposes to record the differences between actual USGAAP incremental transition costs and estimated USGAAP incremental transition costs for the 2013 and 2014 Transmission Rate test years.

a) Hydro One's adoption of USGAAP is a one-time occurrence. Please explain why Hydro One would need continuance of the Impact for Changes in USGAAP variance account and the USGAAP Incremental Transition Costs variance account, when USGAAP was adopted by Hydro One for financial reporting purposes on January 1, 2012.

b) Please disclose the balances in the following variance accounts as at June 30, 2012:
   i. Impact for Changes in US GAAP variance account
   ii. US GAAP Incremental Transition Costs variance account

c) Please disclose the estimated USGAAP incremental transition costs embedded in the proposed 2013 and 2014 Transmission Rate test years. Please explain why Hydro One is seeking to recover such amounts in the 2013 and 2014 test years when the adoption of USGAAAP occurred in 2012.

Response

a) The Impact for Changes in USGAAP Variance Account was established and is potentially required for 2012 only. The account is required to accommodate any differences that are identified up to the finalization of the 2012 Hydro One

Transmission audited financial statements. As of Quarter 2 no differences have been identified. Hydro One currently does not expect any entries will be required to this account in the test years.

The USGAAP Transition Costs Variance Account is still appropriate to maintain during 2013/2014 rate years because Hydro One could still incur unanticipated incremental transition costs in early 2013 as the annual financial statements are finalized. Based on the IFRS cost account imposed by the Board's Accounting Procedures Handbook, Hydro One did not consider it appropriate to propose that the account be discontinued until it was certain that no entries would be made.

b)
 i. $Nil
 ii. $Nil

c) There are no US GAAP incremental transition costs embedded in the proposed 2013 and 2014 Transmission revenue requirement for the test years; as such Hydro One is not seeking recovery through Transmission revenue requirement.

Ontario Energy Board (Board Staff) INTERROGATORY #80 List 1

Issue 19 Are the proposed amounts, disposition and continuance of Hydro One's existing Deferral and Variance accounts appropriate?

Interrogatory

Ref: Exhibit F1/Tab1/Sch1 and Exhibit F1/Tab1/Sch2
As per Exhibit F1/Tab 1/Schedule 2, Hydro One stated that it proposes to continue to record the difference between the actual pension costs booked using the actuarial assessment provided by Mercer and filed with the Financial Services Commission of Ontario ("FSCO") in September 2010, and the estimated pension costs approved by the Board as part of 2013 and 2014 Transmission Rates.

As per Exhibit F1/Tab 1/Schedule 1, Hydro One proposes to recover from ratepayers a balance of $12.8 million in the Pension Cost Differential Account as at December 31, 2012.

a) Please provide a breakdown of the composition of the $12.8 million balance in the Pension Cost Differential Account as at December 31, 2012. Please show how the debits and credits were derived and provide supporting documentation.

b) If the Board grants the approval for Hydro One to continue the use of the Pension Cost Differential Account, why is Hydro One proposing to generate balances in the account going forward using the actuarial assessment provided by Mercer as at December 31, 2009 and filed with the FSCO in September 2010, instead of the actuarial assessment expected to be provided by Mercer as at December 31, 2012? Please explain.

c) Please explain why annual Accounting Updates to the actuarial assessments prepared by Mercer every three years are not proposed to be used in calculating the balance in the Pension Cost Differential Account.

d) Please explain if the Pension Cost Differential Account would be required if Hydro One switched to the accrual basis for accounting for pension costs for regulatory purposes.

Response

a) The Pension Cost Differential Account 2012 balance of $12.8 million contains two elements, principal variance amounts and interest improvement on the principal amounts.

The principal variance amounts recognized in this account are defined as the difference between, the Board approved pension costs attributable to Base Pensionable Earnings (BPE) only and, the actual incurred pension contributions related BPE costs for transmission.

The interest improvement element is recorded monthly on the prior month's principal only closing balance of the account using the rate published by the Board. For further breakdwon of the composition of the $12.8 million, please refer to Exhibit 1, Tab 19, Schedule 1.01 Staff 77, Appendix A.

Table 1
Breakdown of the Transmission Pension Cost Differential Account

As at December 31, 2012	$M
Principal	$12.4
Interest Improvement	$0.4
Total	**$12.8**

Generic Accounting entries

Dr: 2405 Other Regulatory Liabilities sub-account - Pension Cost Differential Account
Cr: 4050 Revenue Adjustment

Entry to record the principal pension cost BPE differential.

Dr: 2405 Other Regulatory Liabilities sub-account - Pension Cost Differential Account
Cr: 6035 Other Interest Expense – sub account Pension Cost Differential Interest Improvement

Entry to record Interest Improvement on principal balance of the account.

For further details of the entries in this account please refer to the continuity schedule submitted as Exibit I, Tab 19, Schedule 1.01 Staff 77 a)

b) If the Board grants the approval for Hydro One to continue the use of the Pension Cost Differential Account, Hydro One proposes to continue to record variances between its planned pension contributions and actual contributions arising from changes in BPE. In addition, for the test years, the account would be impacted by contribution variances arising from any actuarial valuations performed that impact these periods. Please see Exhibit I, Tab 7, Schedule 3.23 EP 49, Part b) for further information on the valuations.

c) Mercer performs annual accounting updates to their triennial actuarial assessments to derive an estimate of the accrual basis asset/liability balance to be used for external financial reporting purposes. As the variance between cash contributions is recorded in the variance account, the annual accounting update to the actuarial assessment has no impact.

d) The Pension Cost Differential Account would still be required if Hydro One switched to the accrual basis for accounting for pension costs for regulatory purposes as variances driven by changes in base pensionable earnings or actuarial valuations could still occur in the test years.

Energy Probe (EP) INTERROGATORY #61 List 1

Issue 19 Are the proposed amounts, disposition and continuance of Hydro One's existing Deferral and Variance accounts appropriate?

Interrogatory

Ref: Exhibit F1, Tab 1, Schedule 2, Page 5

a) Please explain in more detail how the costs for the External Revenue Partnership TPA will be recorded. For example, will it be gross revenue or net revenue after deduction of base payroll costs?

Response

a) Please refer to Exhibit, Tab 20, Schedule 1.01 Staff 81, part b) for the detail accounting entries relating to the External Revenue Partnership Transmission Project account. Hydro One Networks proposes to record gross revenues equal to amounts billed to affiliate partnerships in the account.

School Energy Coalition (SEC) INTERROGATORY #38 List 1

Issue 19 Are the proposed amounts, disposition and continuance of Hydro One's existing deferral and variance accounts appropriate?

Interrogatory

[E1-1-1/p.1]
Please expand Table 1 to include 2008-2012.

Response

The table below includes 2008-12 Board Approved revenue requirement along with the proposed 2013-14 revenue requirement.

Particulars	2008	2009	2010	2011	2012	2013	2014
OM&A	387.5	415.0	426.2	418.8	427.1	453.3	459.7
Depreciation	256.1	258.0	281.3	301.8	332.8	346.7	374.7
Income Taxes	69.1	41.1	40.0	64.0	51.5	46.4	55.2
Cost of Capital[1]	457.4	464.9	509.8	561.0	607.1	618.1	668.1
Total Revenue Requirement	**1,170.1**	**1,179.0**	**1,257.3**	**1,345.6**	**1,418.4**	**1,464.5**	**1,557.7**

[1] Includes Interest Capitalized recovery on the Niagara Reinforcement Project.

School Energy Coalition (SEC) INTERROGATORY #39 List 1

Issue 19 Are the proposed amounts, disposition and continuance of Hydro One's existing deferral and variance accounts appropriate?

Interrogatory

[F1-1-2/p.4]
Please provide the latest balance and accounting entries of the East-West Tie Deferral Account.

Response

No entries have been booked to the East-West Tie Deferral Account as at June 30, 2012.

Consumers Council of Canada (CCC) INTERROGATORY #37 List 1

Issue 19 Are the proposed amounts, disposition and continuance of Hydro One's existing deferral and variance accounts appropriate?

Interrogatory

(Ex. F1/T1/S1/p. 4) For each year 2009-2012 please provide the forecast of Export Revenue and the actual amounts. Please explain any variances.

Response

	2009	2010	2011	2012
Excess Export Service Revenue ($M)	$16.8	$16.3	$30.2	$29.3
Board Approved Excess Export Service Revenue ($M)	$12.0	$12.0	$16.0	$16.0

The variance between the Excess Export Service Revenue and the Board approved revenue is due to actual exports being higher than planned. The variances in 2011 and 2012 are higher because the export rate (ETS) was increased from $1/MWH to $2/MWH, however the total Board approved revenue only increased from $12M to $16M.

The variances in excess export service revenues versus board approved in 2009 to 2011 were tracked in a variance account for disposition in this proceeding. The variance in 2012 is tracked in a variance account for future disposition. Note to reconcile to the balance in Exhibit F1, Tab 1, Schedule 1, Table 2, the 2011 disposition of $4.9 million and interest improvement must be considered.

Consumers Council of Canada (CCC) INTERROGATORY #38 List 1

Issue 19 Are the proposed amounts, disposition and continuance of Hydro One's existing deferral and variance accounts appropriate?

Interrogatory

(Ex. F1/T1/S1/p. 3) For each year 2009-2012 please provide forecast and actual amounts of External Secondary Land Use Revenue. Please explain any variances. Please provide a detailed explanation as to the nature of these costs.

Response

$M	2009 Fcst	2009 Actual	2010 Fcst	2010 Actual	2011 Fcst	2011 Actual	2012 Fcst	2012[1] Actual
Secondary Land Use	(11.4)	(14.2)	(11.3)	(17.4)	(12.6)	(20.6)	(13.3)	N/A

[1]2012 full year results are not yet available

In general, variances observed between budget and actual Secondary Land Use Revenues in historic years 2009-2011 are attributable to one time transactions associated with the Provincial Secondary Land Use Program (PSLUP) for granting easement rights and operational land sales. The transactions typically represent lump sum consideration for easements granted (e.g., water mains) and operational land sales completed (e.g. roadway).

Examples of such transactions in historic years include:

- In 2010 - land sale to the TTC for a parking lot at the new Finch West subway station, land sale to City of Mississauga for a municipal road, granting easement rights for an access road to the new Niagara Convention Civic Center and release of easement rights to Toronto Hydro (North York);
- In 2011 granting easement rights to Municipality of York and City of Toronto for trunk sewer line.

Consumers Council of Canada (CCC) INTERROGATORY #39 List 1

Issue 19 Are the proposed amounts, disposition and continuance of Hydro One's existing deferral and variance accounts appropriate?

Interrogatory

(Ex. F2/T1/S1/p. 1) Please explain why HONI is not seeking disposition of the Market Ready Costs, OEB Incremental Costs and IFRS Incremental Costs.

Response

Hydro One decided to write off, OEB Incremental Assessment Costs, ($0.1M), and IFRS Incremental Transition Costs, $0.2 M, due to the materiality level of these costs. Market Ready, $0.8M, was also written off after giving consideration to its materiality level and the age of the account, as discussed in Exhibit I, Tab 19, Schedule 1.01 Staff 77, part c).

Ontario Energy Board (Board Staff) INTERROGATORY #81 List 1

Issue 20 Are the proposed new Deferral and Variance Accounts appropriate?

Interrogatory

Ref: Exhibit A/Tab2/Sch1 and Exhibit F1/Tab1/Sch2
As per Exhibit A/Tab2/Schedule1, Hydro One is seeking the establishment of the following new deferral accounts in this proceeding:

i. External Revenue – Partnership Transmission Projects deferral account The intent of the External Revenue – Partnership Transmission Projects Account is to record costs for services provided by Hydro One employees for work they are performing for partnership companies.

ii. Long-Term Transmission Future Corridor Acquisition and Development deferral account The establishment of the Long-Term Transmission Future Corridor Acquisition and Development Account is to allow Hydro One Transmission to record transmission planning and study costs associated with preliminary corridor routing considerations for new transmission infrastructure.

Page 55 of the *Filing Requirements For Electricity Transmission and Distribution Applications* issued by the Board on June 28, 2012 [EB-2006-0170] states:

In the event an applicant seeks an accounting order to establish a new deferral/variance account, the following eligibility criteria must be met:

- Causation - The forecasted expense must be clearly outside of the base upon which rates were derived.
- Materiality – The forecasted amounts must exceed the Board-defined materiality threshold and have a significant influence on the operation of the distributor; otherwise they should be expensed in the normal course and addressed through organizational productivity improvements.
- Prudence - The nature of the costs and forecasted quantum must be reasonably incurred although the final determination of prudence will be made at the time of disposition. In terms of the quantum, this means that the applicant must provide evidence demonstrating as to why the option selected represents a cost-effective option (not necessarily least initial cost) for ratepayers.

In addition, applicants must include a draft accounting order which must include a description of the mechanics of the account, including providing examples of general ledger entries, and the manner in which the applicant proposes to dispose of the account at the appropriate time.

a) Please provide an explanation as to how Hydro One meets each of the above eligibility criteria for the proposed establishment of the following new deferral accounts:

i. External Revenue – Partnership Transmission Projects deferral account
ii. Long-Term Transmission Future Corridor Acquisition and Development deferral account

b) Please prepare a draft accounting order for the two new proposed deferral accounts mentioned in part a), including a description of the mechanics of the account, proposed journal entries, and the manner in which Hydro One plans to dispose of the account.

c) Regarding the External Revenue – Partnership Transmission Projects deferral account, Hydro One proposes to track employee time and any expenses and the resulting costs will be invoiced to the appropriate partnered company. Is any dollar amount with respect to this employee time and the associated expenses incorporated in the proposed 2013 and 2014 test year revenue requirement?

i. If so, please state the dollar amount and specific section of the revenue requirement.
ii. If not, please state where this amount is captured.
iii. If so, please provide an explanation as to why this amount is captured in the revenue requirement and not excluded from the revenue requirement.
iv. Please list the partnership companies and the approximate amounts attributable to each partnership company that would be tracked in the External Revenue – Partnership Transmission Projects deferral account.

d) Regarding the Long-Term Transmission Future Corridor Acquisition and Development deferral account, Hydro One stated that it has not included the costs for this work in the 2013 or 2014 revenue requirement. Please explain in detail as to why an estimate cannot be made for these costs and why a deferral account is necessary.

Response

a) Hydro One does not believe that the eligibility criteria of materiality and prudence should be applicable to the establishment of a deferral account. Hydro One believes that the materiality threshold is more appropriately reviewed upon disposition of a deferral account, when the account balance is known. Once disposition of the account balance has been requested, then the prudency of those costs should be subject to review. This said the following explanations are provided with respect to how the eligibility criteria are met.

Causation:

(i) External Revenue – Partnership Transmission Project deferral account

Cost for services provided by Hydro One employees for work they are performing for partnership companies are embedded in the current requested revenue requirement. The purpose of the requested deferral account is to record the revenue equal to the amount invoiced to partnership companies for work performed by Hydro One Transmission employees.

(ii) Long–Term Transmission Future Corridor Acquisition and Development deferral account

As indicated in Exhibit F1, Tab 2, Schedule 1, Hydro One Transmission has not included costs related to the Long–Term Transmission Future Corridor Acquisition and Development deferral account in its 2013-2014 requested revenue requirement.

Materiality:

Hydro One Transmission's materiality threshold is $1 million, per the OEB's Filing Requirements for Electricity Transmission and Distribution Applications (Section 2.4.4) issued June 28, 2012.

(i) External Revenue – Partnership Transmission Project deferral account

When Hydro One Transmission requested this account, the premise was that there would be Hydro One employees engaged in working for EWT L.P. throughout Phase 1 of the designation process (EB-2011-0140). As of July 31, 2012, Hydro One has disengaged from these activities in compliance with the Board's Decision in Phase 1 of this hearing. As such, the forecast account balance, including future partnership ventures, will likely not meet the Board's materiality threshold. That being said, as this account is for the benefit of Hydro One Transmission's ratepayers, and the materiality of costs related to future partnerships is unknown at this time, Hydro One still believes the account is appropriate.

(ii) Long–Term Transmission Future Corridor Acquisition and Development deferral account

Hydro One believes that the costs to be tracked in this account will be material. Transmission planning related to environmental studies and assessments, engineering studies, public and First Nations and Métis consultations and land assessments all require considerable time, effort and research and are important elements of transmission planning and property acquisition.

Prudence:

(i) External Revenue – Partnership Transmission Project deferral account

The account will ultimately lower ratepayer's revenue requirement and is thus a cost-effective option.

(ii) <u>Long–Term Transmission Future Corridor Acquisition and Development deferral account</u>

Hydro One is aware that the prudence of expenditures recorded in this account will be subject to future review upon disposition. Without the use of a deferral account, ratepayers would have costs embedded in their rates that Hydro One Transmission would have had to forecast without having proper understanding of the type, level and timing of such costs. This would not meet the Board's general prudency standard.

b) Please see Proposed Accounting Entries on page 8 and 9 of this exhibit.

c) Yes, the dollar amount with respect to employees' time and associated expenses is included in the proposed 2013 and 2014 test years' revenue requirements.

i. The employee costs included in the 2013 and 2014 test years' revenue requirements include full salary, benefits and associated employment expenses. These costs are included in the shared services budgets of the function that supports this initiative. An exact dollar amount cannot be provided as the individuals and the number of employees working with partnered companies will vary throughout the year, as new partnered companies emerge or circumstances change and also the individual levels of effort cannot be predicted even for known arrangements.

ii. Not applicable

iii. This amount is still in the revenue requirement as Hydro One Transmission is unable to forecast the amount of time any specific employee may spend on a partnership company's activities. For instance, if Hydro One had attempted to forecast the amount of staff time associated with the EWT L.P, that amount would now be overstated as a result of the Phase 1 Decision in EB-2011-0140 requiring Hydro One Networks Inc. to withdraw employee participation in the EWT LP's designation Phase 2 process on July 28, 2012 (see EB-2011-0140 Hydro One letter to the Board dated July 31, 2012).

iv. The current partnership company is EWT L.P. The Ontario government through the Long Term Energy Plan is encouraging transmission partnerships with First Nations and Metis groups and therefore new partnerships may emerge in the test years. Hydro One is unable to approximate the amounts attributable to each partnership company at this time as the extent of work required is not known at this time.

d) Hydro One did not include Long Term Transmission Future Corridor Acquisition and Development costs in the 2013 and 2014 revenue requirement due to the variable and unpredictable nature of the work and the potential large materiality of these costs. Hydro is expecting to collaborate with the Ministry of Transportation and other interested utilities in the planning of multi-use corridors (i.e. consistent with the Ontario Provincial Policy Statement of 2005). This provides opportunities for cost sharing, but is also a source of considerable uncertainty in design of the planning process and the associated cost of approvals, land acquisition etc. Uncertainties in the location, size, timing and number of potential future transmission corridors investigated will also impact the estimated costs.

For these reasons, Hydro One believes due to the unpredictable and uncertain nature of the costs, that a deferral account treatment is the most appropriate approach.

HYDRO ONE NETWORKS INC.

DRAFT ACCOUNTING ORDER

Hydro One Networks Inc. Transmission (Hydro One Transmission) requested permission (EB-2012-0031) to establish two deferral accounts.

1. External Revenue – Partnership Transmission Projects deferral account

Hydro One Transmission intends to establish a new deferral account *External Revenue – Partnership Transmission Projects Deferral Account (“ER-PTPDA”).* Hydro One will record costs related to services provided by Hydro One Networks employees to partnership companies, e.g. for work not directly to the benefit of Hydro One Transmission’s ratepayers. These costs would be invoiced to the appropriate partnered company, and current transmission revenues equal to the invoiced amount would be recorded in the ER-PTPDA for reduction of future transmission revenue requirements.

The account would be established as Account 1508, Other Regulatory Assets, sub-account ‘External Revenue - Partnership Transmission Projects Deferral Account’.

Hydro One Transmission would record interest on any balance in the sub-account using the interest rates set by the Board. Simple interest will be calculated on the opening monthly balance of the account until the balance is fully disposed.

2. Long-Term Transmission Future Corridor Acquisition and Development Account

Hydro One Transmission intends to establish a new deferral account - the Long-Term Transmission Future Corridor Acquisition and Development Account. Hydro One would record transmission planning and study costs associated with preliminary corridor routing considerations for new transmission infrastructure in this account.

The account shall be established as Account 1508, Other Regulatory Assets, sub-account ‘Long-Term Transmission Future Corridor Acquisition and Development Account’.

Hydro One Transmission will record interest on any balance in the sub-account using the interest rates set by the Board. Simple interest will be calculated on the opening monthly balance of the account until the balance is fully disposed.

Detailed accounting entries for the above two sub-accounts are attached as Attachment 1.

Proposed Disposition of the Accounts

Hydro One Transmission would request disposition of the actual audited regulatory account values plus forecast interest on the principal balances at a future transmission rates application.

Proposed Accounting Entries

USofA #		Account Description

1) External Revenue – Partnership Transmission Projects Deferral Account

DR	4XXX	Transmission OM&A Expense accounts
CR	2205	Accounts Payable

Initial entry to record the OM&A costs incurred by Hydro One in support of the Partnership Transmission Projects.

Dr:	1100	Accounts Receivable - Customers
Cr:	4XXX	Transmission Revenue Accounts Range

Standard entry to record Transmission revenue.

Dr:	1200	Accounts Receivable from Associated Companies
Cr:	4235	Miscellaneous Services Revenue

Entry to record amounts billed to affiliate partnership.

Dr:	4XXX	Transmission Revenue Accounts Range
Cr:	2405	Other Regulatory Liabilities – sub account “External Revenue – Partnership Transmission Projects deferral account”

To record the Transmission revenues received in respect of amounts to be billed to affiliate for Partnership Transmission Projects in a deferral account for future disposition.

Dr:	6035	Other Interest Expense
Cr:	2405	Other Regulatory Liabilities – sub account “External Revenue – Partnership Transmission Projects deferral account”

To record interest improvement on the principal balance of the “External Revenue – Partnership Transmission Projects deferral account”.

2) <u>Long-Term Transmission Future Corridor Acquisition and Development Account</u>

Dr: 48XX Operational Transmission Expense account range

Cr: 2205 Accounts Payable

Initial entry to record OM&A costs incurred for Long-Term Transmission Future Corridor Acquisition and Development costs.

Dr: 1508 Other Regulatory Assets – Sub account "Long-Term Transmission Future Corridor Acquisition and Development Account"

Cr: 48XX Operational Transmission Expense account range

To record incremental costs incurred for supporting Long-Term Transmission Future Corridor Acquisition and Development activities in a deferral account for future recovery.

Dr: 1508 Other Regulatory Assets – Sub account "Long-Term Transmission Future Corridor Acquisition and Development Account"

Dr: 6035 Other Interest Expense

To record interest improvement on the principal balance of the "Long-Term Transmission Future Corridor Acquisition and Development Account".

<u>Consumers Council of Canada (CCC) INTERROGATORY #40 List 1</u>

Issue 20 Are the proposed new deferral and variance accounts appropriate?

<u>Interrogatory</u>

(Ex. F1/T1/S2/p. 5) Please explain, in greater detail, what specific costs HONI is seeking to record in the Partnership Transmission Projects Account. Please provide current examples of these arrangements. What are the expected costs and revenues for these arrangements for the test years? Please explain how the costs and revenues will be accounted for in the account.

<u>Response</u>

Please refer to Exhibit I, Tab 20, Schedule 1.01 Staff 81 for details relating to the External Revenue Partnership Transmission Projects account.

Consumers Council of Canada (CCC) INTERROGATORY #41 List 1

Issue 20 Are the proposed new deferral and variance accounts appropriate?

Interrogatory

(Ex. F1/T1/S2/p. 5) Please indicate the anticipated costs for Long-Term Future Corridor Acquisition and Development for the two test years. Please explain all of the cost categories that HONI is proposing to record in this new account.

Response

Hydro One expects to incur approximately $6 million in the test years associated with securing future corridor acquisition in the Northern Brampton and Southern Caledon area.

Hydro One plans to participate in Joint Use Transportation and Transmission Corridor Planning with the City of Brampton and the Ministry of Transportation (MTO) to begin the required conceptual environmental assessment (EA) work for future transmission corridors. Both the MTO and the City of Brampton have already commenced EA work. The preliminary work that will be recorded in the deferral account will include the cost of conducting the necessary EA work for the North-South transmission corridor, capacity funding for First Nations and Métis relations, public consultations and preliminary engineering studies on the corridor.

Vulnerable Energy Consumers Coalition (VECC)INTERROGATORY #34 List 1

Issue 21 Is the cost allocation proposed by Hydro One appropriate?

Interrogatory

Reference: Exhibit G1, Tab 2, Schedule 1, page 12

a) What year's data is used to determine the Non-Coincident Peak Demand used (per lines 16-24) to determine the Generator portion of shared connection facilities?

Response

a) The Non-Coincident Peak Demand is based on the 2013 load forecast data.

<u>Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #35 List 1</u>

Issue 21 Is the cost allocation proposed by Hydro One appropriate?

<u>Interrogatory</u>

Reference: Exhibit G1, Tab 5, Schedule 1, pages 2- 3

a) Please contrast the actual number of Hydro One owned metering installations in 2011 and 2012 with the number that were forecast for purposes of setting rates in EB-2010-0002.

b) How much notice does Hydro One typically receive when a customer decides to make alternate arrangements and cease to use Hydro One as its Meter Service Provider?

<u>Response</u>

a) The information requested is provided below:

	Mid-year # of Meters	
	2011	2012
Actual	143	138
Forecast	100	75

b) Depending on the exit option chosen, which can range from a simple deregistering of metering facilities to installing new metering facilities either inside or outside the existing transmission station, the legacy MSP services arrangement could end anywhere from 1 month to 3 years (defined as when customer stops paying for these services) after the exit option is chosen.

Vulnerable Energy Consumers Coalition (VECC)INTERROGATORY #36 List 1

Issue 21 Is the cost allocation proposed by Hydro One appropriate?

Interrogatory

Reference: Exhibit G1, Tab 6, Schedule 1, page 2, lines 8- 9

a) Please provide a copy of the "review" undertaken to confirm the estimated cost of LVSG and the continued appropriateness of the 19% factor.

Response

a) The review consisted of consulting with Hydro One planning staff for new information that could be used to update the calculation of the LVSG factor. A minor update was made to reflect the costs for a recently completed transformer station. However, the 19% LVSG factor is confirmed as remaining appropriate.

Vulnerable Energy Consumers Coalition (VECC)INTERROGATORY #37 List 1

Issue 21 Is the cost allocation proposed by Hydro One appropriate?

Interrogatory

Reference: Exhibit G2, Tab 1, Schedule 1

a) Please provide a schedule that lists the new Transmission Lines that were not included in EB-201 0-0002. In each case, please indicate the relevant project reference number (from either the EB-201 0-0002 Application or this Application) that describes the investment, note the functional category it has been assigned to and indicate why.

b) Please provide a schedule that lists those Transmission Lines whose functional categorization has changed from that in EB-201 0-0002 and provide an explanation as to the reason for the change.

Response

a) There are 53 new transmission line segments noted in EB-2012-0031, Exhibit G2, Tab 1, Schedule 1. Table 1 lists the new transmission line segments and project reference numbers. The functional categorization of these new Transmission Lines is assigned according to the definitions set out in Exhibit G1, Tab 2, Schedule 1, Section 3.0.

Table 1: New Transmission Line Segments

Operation Designation	Sect	From	To	Functional Category EB-2012-0031	Project reference number
B5G	20	Arlen MTS JCT	Hanlon JCT	LC	EB-2010-0002 D1/T3/S3, Table 4 'Other Historical Projects": Tap to customer owned Arlen MTS
B5G	21	Arlen MTS JCT	Arlen MTS	LC	EB-2010-0002 D1/T3/S3, Table 4 'Other Historical Projects": Tap to customer owned Arlen MTS
B6G	13	Arlen MTS JCT	Hanlon JCT	LC	EB-2010-0002 D1/T3/S3, Table 4 'Other Historical Projects": Tap to customer owned Arlen MTS
B6G	14	Arlen MTS JCT	Arlen MTS	LC	EB-2010-0002 D1/T3/S3, Table 4 'Other Historical Projects": Tap to customer owned Arlen MTS
B82V	8	York EnergyCentr JCT	Holland Marsh JCT	DFL	Project D29 in EB-2010-0002 Exhibit D2, Tab 2, Schedule 3. Tap to customer owned York Energy Centre CGS

Operation Designation	Sect	From	To	Functional Category EB-2012-0031	Project reference number
B82V	9	York EnergyCentr JCT	York EnergyCentr CGS	DFL	Project D29 in EB-2010-0002 Exhibit D2, Tab 2, Schedule 3. Tap to customer owned York Energy Centre CGS
B83V	8	York EnergyCentr JCT	Holland Marsh JCT	DFL	Project D29 in EB-2010-0002 Exhibit D2, Tab 2, Schedule 3. Tap to customer owned York Energy Centre CGS
B83V	9	York EnergyCentr JCT	York EnergyCentr CGS	DFL	Project D29 in EB-2010-0002 Exhibit D2, Tab 2, Schedule 3. Tap to customer owned York Energy Centre CGS
C12	6	Bloomsburg JCT	Bloomsburg MTS	LC	EB-2010-0002 D1/T3/S3, Table 4 ‘Other Historical Projects”: Tap to customer owned Bloomsburg MTS
C23Z	7	Comber WF JCT	Comber WF CTS	TDF	EB-2010-0002 D1/T3/S3, Table 5 ‘Other Historical Projects”: Tap to customer owned Comber WF CTS (Comber Wind Limited Partnership)
C23Z	8	Comber WF JCT	Sandwich JCT	DFL	EB-2010-0002 D1/T3/S3, Table 5 ‘Other Historical Projects”: Tap to customer owned Comber WF CTS (Comber Wind Limited Partnership)
C23Z	5	Dillon RWEC CGS JCT	KEPA Wind Farm JCT	DFL	EB-2010-0002 D1/T3/S3, Table 5 ‘Other Historical Projects”: Tap to customer owned Dillon WREC CGS (Dillon Wind Centre)
C23Z	6	Dillon RWEC CGS JCT	Dillon RWEC CGS	TDF	EB-2010-0002 D1/T3/S3, Table 5 ‘Other Historical Projects”: Tap to customer owned Dillon WREC CGS (Dillon Wind Centre)
C24Z	5	Comber WF JCT	Sandwich JCT	DFL	EB-2010-0002 D1/T3/S3, Table 5 ‘Other Historical Projects”: Tap to customer owned Comber WF CTS (Comber Wind Limited Partnership)
C24Z	6	Comber WF JCT	Comber WF CTS	TDF	EB-2010-0002 D1/T3/S3, Table 5 ‘Other Historical Projects”: Tap to customer owned Comber WF CTS (Comber Wind Limited Partnership)
D4W	3	Kitchener #9 JCT	Kitchener MTS#9	TDF	EB-2010-0002 D1/T3/S3, Table 4 ‘Other Historical Projects”: Tap to Kitchener MTS# 9
D4W	2	Kitchener #9 JCT	Buchanan TS	DFL	EB-2010-0002 D1/T3/S3, Table 4 ‘Other Historical Projects”: Tap to customer owned Kitchener MTS# 9
D5W	3	Kitchener #9 JCT	Kitchener MTS#9	TDF	EB-2010-0002 D1/T3/S3, Table 4 ‘Other Historical Projects”: Tap to customer owned Kitchener MTS# 9
D5W	2	Kitchener #9 JCT	Buchanan TS	DFL	EB-2010-0002 D1/T3/S3, Table 4 ‘Other Historical Projects”: Tap to customer owned Kitchener MTS# 9

Operation Designation	Sect	From	To	Functional Category EB-2012-0031	Project reference number
H9K	18	Kapuskasing R Jct	Tembec Kapuskas CTS	OTHER	EB-2008-0272 D1/T3/S3, Table 4 ‘Other Historical Projects”: Tap to customer owned Tembec Kapuskas CTS
K12	2	Woodstock TS	Commerce Way TS	LC	Project D16 in EB-2010-0002 Exhibit D2, Tab 2, Schedule 3
K2Z	16	Gosfield CGS JCT	Kingsville TS	LC	EB-2010-0272 D1/T3/S3, Table 5 ‘Other Historical Projects”: Tap to customer owned Gosfield Wind CGS
K2Z	17	Gosfield CGS JCT	Gosfield Wind CGS	LC	EB-2010-0002 D1/T3/S3, Table 5 ‘Other Historical Projects”: Tap to customer owned Gosfield Wind CGS
K3	1	Kapuskasing TS	Kapuskasing R Jct	LC	EB-2010-0002 D1/T3/S3, Table 4 ‘Other Historical Projects”: Tap to customer owned Tembec Kapuskas CTS
K4	8	Matachewan JCT	Young-Davidson CTS	LC	EB-2010-0002 D1/T3/S3, Table 4 ‘Other Historical Projects”: Tap to customer owned Young-Davidson CTS
K4	9	93K4-89 JCT	Matachewan JCT	LC	EB-2010-0002 D1/T3/S3, Table 4 ‘Other Historical Projects”: Tap to customer owned Young-Davidson CGS
K6Z	11	Pte-Aux-RochesWF JCT	Belle River JCT	LC	EB-2010-0002 D1/T3/S3, Table 5 ‘Other Historical Projects”: Tap to customer owned Pte-Aux-Roches WF CGS (Pointe-Aux-Roche Wind Farm)
K6Z	12	Pte-Aux-RochesWF JCT	Pte-Aux-RochesWF CGS	LC	EB-2010-0002 D1/T3/S3, Table 5 ‘Other Historical Projects”: Tap to customer owned Pte-Aux-Roches WF CGS (Pointe-Aux-Roche Wind Farm)
K7	2	Woodstock TS	Commerce Way TS	LC	Project D16 in EB-2010-0002 Exhibit D2, Tab 2, Schedule 3
M23L	2	Greenwich WF CGS JCT	Lakehead TS	DFL	EB-2010-0002 D1/T3/S3, Table 5 ‘Other Historical Projects”: Tap to customer owned Greenwich WF CSS (Greenwich Wind Farm)
M23L	4	Greenwich WF CGS JCT	Greenwich LakeWF CSS	TDF	EB-2010-0002 D1/T3/S3, Table 5 ‘Other Historical Projects”: Tap to customer owned Greenwich WF CSS Greenwich Wind Farm)
M24L	2	Greenwich WF CGS JCT	Lakehead TS	DFL	EB-2010-0002 D1/T3/S3, Table 5 ‘Other Historical Projects”: Tap to customer owned Greenwich WF CSS Greenwich Wind Farm)
M24L	4	Greenwich WF CGS JCT	Greenwich LakeWF CSS	TDF	EB-2010-0002 D1/T3/S3, Table 5 ‘Other Historical Projects”: Tap to customer owned Greenwich WF CSS Greenwich Wind Farm)

Operation Designation	Sect	From	To	Functional Category EB-2012-0031	Project reference number
M2W	25	Umbata Falls JCT	Williams Mine JCT	LC	EB-2010-0002 D1/T3/S3, Table 5 'Other Historical Projects": Tap to customer owned Umbata Falls JCT
M30A	5	Ellwood MTS JCT	Ellwood MTS	DFL	EB-2010-0002 D1/T3/S3, Table 4 'Other Historical Projects": Tap to customer owned Ellwood MTS
M30A	6	Ellwood MTS JCT	Hawthorne TS	DFL	EB-2010-0002 D1/T3/S3, Table 4 'Other Historical Projects": Tap to customer owned Ellwood MTS
M31A	5	Ellwood MTS JCT	Ellwood MTS	DFL	EB-2010-0002 D1/T3/S3, Table 4 'Other Historical Projects": Tap to customer owned Ellwood MTS
M31A	6	Ellwood MTS JCT	Hawthorne TS	DFL	EB-2010-0002 D1/T3/S3, Table 4 'Other Historical Projects": Tap to customer owned Ellwood MTS
P45	2	Markham #4 JCT	Buttonville TS	LC	EB-2008-0272 D1/T3/S3, Table 4 'Other Historical Projects": Tap to customer owned Markham JCT
P45	3	Markham #4 JCT	Markham MTS #4	LC	EB-2008-0272 D1/T3/S3, Table 4 'Other Historical Projects": Tap to customer owned Markham MTS # 4
P46	2	Markham #4 JCT	Buttonville TS	LC	EB-2008-0272 D1/T3/S3, Table 4 'Other Historical Projects": Tap to customer owned Markham MTS # 4
P46	3	Markham #4 JCT	Markham MTS #4	LC	EB-2008-0272 D1/T3/S3, Table 4 'Other Historical Projects": Tap to customer owned Markham MTS # 4
S3S	3	KAP LMRP JCT	Kapuskasing R Jct	LC	EB-2008-0272 D1/T3/S3, Table 4 'Other Historical Projects": Tap to customer owned KAP LMRP CTS (Kiewit Alarie Partnership (KAP))
S3S	5	KAP LMRP JCT	KAP LMRP CTS	LC	EB-2008-0272 D1/T3/S3, Table 4 'Other Historical Projects": Tap to customer owned KAP LMRP CTS (Kiewit Alarie Partnership (KAP))
S4S	2	Kapuskasing R Jct	Tembec Kapuskas CTS	LC	EB-2008-0272 D1/T3/S3, Table 4 'Other Historical Projects": Tap to customer owned Tembec Kapuskas CTS
T36B	6	Glenorchy JCT	Palermo TxB JCT	DFL	EB-2010-0002 D1/T3/S3, Table 4 'Other Historical Projects": Tap to customer owned Glenorchy MTS
T36B	7	Glenorchy JCT	Glenorchy MTS #1	TDF	EB-2010-0002 D1/T3/S3, Table 4 'Other Historical Projects": Tap to customer owned Glenorchy MTS
T37B	6	Glenorchy JCT	Palermo TxB JCT	DFL	EB-2010-0002 D1/T3/S3, Table 4 'Other Historical Projects": Tap to customer owned Glenorchy MTS

Operation Designation	Sect	From	To	Functional Category EB-2012-0031	Project reference number
T37B	7	Glenorchy JCT	Glenorchy MTS #1	TDF	EB-2010-0002 D1/T3/S3, Table 4 'Other Historical Projects": Tap to customer owned Glenorchy MTS
W44LC	7	Duart JCT	Duart TS	OTHER	Project D27 in EB-2010-0002 Exhibit D2, Tab 2, Schedule 3.
W45LS	2	Cowal JCT	Duart JCT	DFL	Project D27 in EB-2010-0002 Exhibit D2, Tab 2, Schedule 3.
W45LS	6	Duart JCT	Spence SS	DFL	Project D27 in EB-2010-0002 Exhibit D2, Tab 2, Schedule 3.
W45LS	7	Duart JCT	Duart TS	TDF	Project D27 in EB-2010-0002 Exhibit D2, Tab 2, Schedule 3.

b) There are 77 transmission line segments out of more than 2,300 line segments on the transmission system for which the functionalization has changed in EB-2012-0031 as compared to EB-2010-0002. The reasons for the functionalization changes are mainly due to a database clean-up and a change in operating configuration, which includes the adding/removing of customer taps to/from an existing line segment. Details are shown in Table 2 below.

Table 2: Line Segment New Rate Pool Assignment

Operation Designation	Section	EB-2012-0031	EB-2010-0002	Reason for change
B8W	4	LC	OTHER	Change in operating configuration
C23Z	4	OTHER	TDF	Changed in operating configuration
C24Z	1	DFL	N	Added customer tap to "N" line
C24Z	2	DFL	N	Added customer tap to "N" line
C24Z	3	DFL	N	Added customer tap to "N" line
C24Z	4	TDF	OTHER	Changed in operating configuration
D1W	1	LC	TDF	Database Cleanup
D4W	1	DFL	N	Added customer tap to "N" line
D5W	1	DFL	N	Added customer tap to "N" line
D7F	1	LC	DFL	Database Cleanup
D7F	2	LC	DFL	Database Cleanup
D7F	3	LC	DFL	Database Cleanup
D7F	4	LC	DFL	Database Cleanup
D7F	5	LC	DFL	Database Cleanup
D7F	6	LC	TDF	Database Cleanup
D7F	9	LC	TDF	Database Cleanup
F12C	1	LC	DFL	Database Cleanup

Operation Designation	Section	EB-2012-0031	EB-2010-0002	Reason for change
F12C	2	LC	DFL	Database cleanup
F12C	3	LC	TDF	Database cleanup
F12C	5	LC	TDF	Database cleanup
F12C	7	LC	DFL	Database Cleanup
K4	3	LC	OTHER	Change in operating configuration
L1S	8	OTHER	LC	Change in operating configuration
L1S	9	LC	OTHER	Change in operating configuration
M20D	6	TDF	DFL	Database Cleanup
M20D	9	LC	DFL	Database Cleanup
M20D	10	LC	DFL	Database Cleanup
M20D	11	LC	TDF	Database cleanup
M20D	15	LC	TDF	Database Cleanup
M20D	16	LC	DFL	Database Cleanup
M23L	1	DFL	N	Added customer tap to “N” line
M24L	1	DFL	N	Added customer tap to “N” line
M31W	1	DFL	N	Added customer tap to “N” line
M31W	2	DFL	N	Added customer tap to “N” line
M31W	3	DFL	N	Added customer tap to “N” line
M9K	1	LC	OTHER	Database cleanup
P4S	10	TDF	OTHER	Change in operating configuration
Q26M	1	DFL	LC	Change in operating configuration
Q26M	2	DFL	LC	Change in operating configuration
Q26M	3	TDF	LC	Change in operating configuration
Q26M	4	DFL	OTHER	Change in operating configuration
Q26M	6	DFL	OTHER	Change in operating configuration
Q2AH	25	OTHER	LC	Change in operating configuration
Q2AH	26	LC	OTHER	Change in operating configuration
Q35M	1	DFL	LC	Change in operating configuration
Q35M	2	DFL	LC	Change in operating configuration
Q35M	3	TDF	LC	Change in operating configuration
Q35M	4	DFL	OTHER	Change in operating configuration
Q35M	5	DFL	OTHER	Change in operating configuration
Q35M	6	DFL	OTHER	Change in operating configuration
Q35M	7	DFL	OTHER	Change in operating configuration
Q5B	6	OTHER	LC	Change in operating configuration
Q5B	7	OTHER	LC	Change in operating configuration
Q6S	7	OTHER	LC	Change in operating configuration
S1R	1	OTHER	LC	Change in operating configuration

Operation Designation	Section	EB-2012-0031	EB-2010-0002	Reason for change
S7M	14	LC	OTHER	Change in operating configuration
T2R	1	OTHER	LC	25 Hz system removed from service
T2R	2	OTHER	LC	25 Hz system removed from service
T2R	3	OTHER	LC	25 Hz system removed from service
T2R	4	OTHER	LC	25 Hz system removed from service
T2R	5	OTHER	LC	25 Hz system removed from service
T2R	6	OTHER	LC	25 Hz system removed from service
T2R	11	OTHER	LC	25 Hz system removed from service
V41H	1	DFL	LC	Change in operating configuration
V41H	2	DFL	LC	Change in operating configuration
V41H	3	DFL	LC	Change in operating configuration
V41H	4	DFL	LC	Change in operating configuration
V41H	6	TDF	LC	Change in operating configuration
V41H	8	TDF	LC	Change in operating configuration
V42H	1	DFL	LC	Change in operating configuration
V42H	2	DFL	LC	Change in operating configuration
V42H	3	DFL	LC	Change in operating configuration
V42H	4	DFL	LC	Change in operating configuration
V42H	5	DFL	LC	Change in operating configuration
V42H	7	TDF	LC	Change in operating configuration
V42H	9	TDF	LC	Change in operating configuration
V42H	10	TDF	LC	Change in operating configuration

Vulnerable Energy Consumers Coalition (VECC)INTERROGATORY #38 List 1

Issue 21 Is the cost allocation proposed by Hydro One appropriate?

Interrogatory

Reference: Exhibit G2, Tab 1, Schedule 2

a) Please provide a schedule that lists the new Transmission Stations that were not included in EB-2010-0002. In each case, please indicate the relevant project reference number (from either the EB-201 0-0002 Application or this Application) that describes the investment, note the functional category it has been assigned to and indicate why.

b) Please provide a schedule that lists those Transmission Stations whose functional categorization has changed from that in EB-2010-0002 and provide an explanation as to the reason for the change.

Response

a) There are six new transmission stations noted in EB-2012-0031, Exhibit G2, Tab 1, Schedule 2. Table 1 lists the new station information, relevant investment project reference number and functional category it has been assigned to. The functional categorization for these new transmission stations is assigned according to the definitions set out in Exhibit G1, Tab 2, Schedule 1, Section 3.0.

Table 1: New Transmission Station List

Station Number	Station Name	Explanation or Project Reference #	Functional categorization (EB-2012-0031)
1310	Hurontario SS	Project D16 in EB-2008-0272, Exhibit D2, Tab 2, Schedule 3.	N
1317	Churchill Meadows TS	Project D27 in EB-2008-0272, Exhibit D2, Tab 2, Schedule 3.	TC
3054	Nobel SS	Project D8 in EB-2008-0272, Exhibit D2, Tab 2, Schedule 3	N
7030	Duart TS	Project D27 in EB-2010-0002, Exhibit D2, Tab 2, Schedule 3.	TC
7238	Karn TS	Project D9 in EB-2010-0002, Exhibit D2, Tab 2, Schedule 3 (Woodstock Area Transmission Reinforcement)	LC
7242	Spence SS	Project D28 EB-2010-0002 Exhibit D2, Tab 2, Schedule 3	N

b) There are three transmission stations whose Functional Category has changed since EB-2010-0002. Table 2 lists the stations with their previous and current functionalization assignments, and the reason for the change.

Table 2: Transmission Station New Rate Pool Assignment

Station Number	Station Name	EB-2010-0002	EB-2012-0031	Reason for the change
4028	Detweiler TS	N,LC,TC	N,LC	Reconfiguration of station
4035	Freeport SS	N,LC	LC	Database Cleanup
4091	Preston TS	N,TC	LC,TC	Database Cleanup

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #39 List 1

Issue 21 Is the cost allocation proposed by Hydro One appropriate?

Interrogatory

Reference: Exhibit G2, Tab 2, Schedule 1

a) Please explain how there can be Transmission Lines that have been categorized as Dual Function Lines but for which there is no Connection portion attributed (e.g., B4V and C23Z).

Response

a) This situation typically occurs when there is only a generator connected to the Dual Function Line, and the generator is forecasted to take no load or only minimal load, such that the rounded percentage share for Line Connection works out to 0%. This situation can also occur when the Dual Function Line serves a new Delivery Point for which there is insufficient historical data on which to base the Delivery Point load forecast.

<u>Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #40 List 1</u>

Issue 21 Is the cost allocation proposed by Hydro One appropriate?

Interrogatory

Reference: Exhibit G2, Tab 3, Schedule 1
Exhibit G2, Tab 3, Schedule 2

a) Are there any Generator Line Connections or Generator Station Connections listed in these two references that were not deemed as Generator Line/Station Connections (in whole or part) in EB-2010-0002?
If so, what is the basis for their inclusion in the current schedule?

Response

a) Yes, there are a number of new Generator Line Connections and Generator Station Connections listed in the referenced Exhibits. The main reason for their inclusion in the current schedules is that 15 new generators have connected to the transmission system from the time of the EB-2010-0002 filing.

Ontario Energy Board (Board Staff) INTERROGATORY #82 List 1

Issue 22 Are the proposed new Deferral and Variance Accounts appropriate?

Interrogatory

Ref: Exhibit A1/Tab14/Sch1 – Green Energy Plan; Exhibit D1/Tab3/Sch3 – Projects approved in EB-2010-0002

In its current Green Energy Plan, Hydro One has identified the projects that were approved in EB-2010-0002. It appears from the evidence that some of these have been delayed and may not be placed in-service on the originally proposed date.

In table format, please identify the projects that were approved as part of Hydro One's Green Energy Plan in EB-2010-0002 and with respect to each project, please provide the following additional information:

(i) The original planned in-service date;

(ii) The new in-service date;

(iii) The Board approved capital expenditure;

(iv) Actual capital expenditures incurred in 2011 and/or 2012(forecast);

(v) If additional capital expenditures are proposed in 2013 and/or 2014, please provide the expenditures by year. Please provide the capital expenditures in the form of amounts (i.e. net costs) that will be added to rate base.

Response

Please find the requested table (Table 1) that includes a breakdown of all projects that were approved as part of Hydro One's Green Energy Plan in EB-2010-002 identifying the original planned in-service date, new in-service date, Board approved capital expenditure, actual capital expenditures incurred in 2011 and/or forecasted 2012, and test year capital expenditure that is booked to rate base.

Table 1
Green Energy Plan (EB-2010-0002) Projects - In-Service Additions

ISD#	Investment Summary Description	Original I/S Year	New I/S Year	Board Approved 2011 ISA	Board Approved 2012 ISA	Actual 2011 ISA	Forecast 2012 ISA	Forecast 2013 ISA	Forecast 2014 ISA
D11	Toronto Area Station Upgrades for Short Circuit Capability: Rebuild Hearn SS	2012	2013	-	83.6	-	-	99.9	4.0
D12	Toronto Area Station Upgrades for Short Circuit Capability: Leaside TS Equipment Update	2012	2014	-	36.9	-	-	18.8	5.1
D13	Toronto Area Station Upgrades for Short Circuit Capability: Manby TS Equipment Update	2013	2014	-	-	-	-	8.3	5.0
D37	In-Line Circuit Breakers #1 (i.e. Summerhaven)	2012	2013	-	20.0	-	-	20.4	-
D38	In-Line Circuit Breakers #2 (i.e. Sandusk)	2012	2013	-	20.0	-	-	21.9	-

In the EB-2010-0002 Decision, D43 and D44 were not approved for inclusion as in-service additions. Instead the projects are being funded through capital contributions from customers.

The actual capital expenditures for these projects in 2011 and the forecast capital expenditures in 2012 are shown in Exhibit D1, Tab 3, Schedule 3, Appendix A, Table 3 as projects D7, D8 and D9 and Table 11 as projects D35 and D36.

The Board approved capital expenditures for these projects for 2011 and 2012 are shown in EB-2010-0002, Exhibit D1, Tab 3, Schedule 3, Appendix A, Table 3 as projects D11, D12 and D13 and in Table 8 as projects D37 and D38.

Ontario Energy Board (Board Staff) INTERROGATORY #83 List 1

Issue 22 Are the proposed new Deferral and Variance Accounts appropriate?

Interrogatory

Ref: Exhibit A/Tab14/Sch1/p 9/Table 1: Projects to Facilitate Green Energy in the Current Application

Please expand Table 1 at the above reference and provide a breakdown of all capital programs under the eight "items" noted in the table. With respect to the capital programs please provide the ISD #, in-service year, Gross Cost, capital contributions, and the test year capital expenditure that are booked to the test year rate base. In a separate table, please identify all projects that are included in the capital expenditure budget in Table 1, but will not be added to the test year rate base. With respect to the capital programs please provide the ISD #, in-service year, Gross Cost, capital contributions and net costs.

Response

Please refer to Table 1 below for a breakdown of all capital programs under the eight "items" noted in Exhibit A, Tab 14, Schedule 1, Table 1 as requested.

Please refer to Table 2 below for a list identifying all projects that are included in the capital expenditure budget in Exhibit A, Tab 14, Schedule 1, Table 1, but will not be added to the test year rate base.

Table 1

Item	ISD#	Project	I/S Year	Project Cost ($M) Gross Cost	Project Cost ($M) Cap. Cont.	In-Service Additions ($M) 2013	In-Service Additions ($M) 2014
1	**D06**	**Reconductor the Lambton TS to Longwood TS 230kV Circuits**	**2014**	**40.0**	**-**	**-**	**40.0**
2	**D05**	**Installation of SVC at Milton SS**	**2015**	**100.0**	**-**	**-**	**-**
3		**FIT Renewable Generation Connections**		**170.4***	**170.2***		
	D22	*Niagara Region Wind Corporation Generation Connection (230 MW)*	*2014*	*50.0**	*50.0**	*-*	*-*
	D25	*Adelaide/Bornish/Jericho Wind Energy Centres (284 MW)*	*2014*	*45.0**	*45.0**	*-*	*-*
		Others (Less than $3 Million)	*Multiple*	*75.4**	*75.2**	*-*	*0.2*
4		**Non-FIT Renewable Generation Connections**		**83.5***	**83.2***		
	D20	*Samsung South Kent Wind Farm (270 MW) (Formerly Chatham Wind Generation)*	*2013*	*4.1**	*4.1**	*-*	*-*
	D21	*Lower Mattagami Generation Connections*	*2013*	*18.3**	*18.0**	*1.7*	*-*
	D23	*Armow Wind Generation Connection (180 MW)*	*2014*	*2.0**	*2.0**	*-*	*-*
	D24	*K2 Wind Generator Connection (270 MW)*	*2014*	*45.0**	*45.0**	*-*	*-*
		Others (Less than $3 Million)	*Multiple*	*14.1**	*14.1**	*-*	*-*
5	**D30**	**Allanburg TS: Upgrade Short Circuit Capability**	**2013**	**19.0**	**-**	**17.0**	**2.0**
6	**D31**	**Hawthorne TS: Upgrade Short Circuit Capability**	**2013**	**11.8**	**-**	**10.8**	**1.0**
7		**Protection and Control Upgrades to Enable Generation Connections to Distribution Systems**		**52.0***	**52.0***	**-**	**-**
	D26	*Transfer Trip Signaling Enhancement*	*Annual*	*13.0**	*13.0**	*-*	*-*
	D27	*Transmission Station P&C Upgrades for DG*	*Annual*	*39.0**	*39.0**	*-*	*-*
8		**Protection and Control Upgrades for the Consequences of Generation already connected to**		**13.8***	**-**		
	D28	*Transmission Work to Mitigate Distance Limitation*	*Annual*	*5.8**	*-*	*2.8*	*3.0*
	D29	*UFLS and Load Rejection Modification*	*Annual*	*5.0**	*-*	*-*	*5.0*
		Others (Less than $3 Million)	*Annual*	*3.0**	*-*	*-*	*3.0*

*Estimates of capital expenditure for 2013 and 2014 only

Table 2

Item	ISD#	Project	I/S Year	Project Cost ($M) Gross Cost	Project Cost ($M) Cap. Cont.	Project Cost ($M) Net Cost
2	D05	Installation of SVC at Milton SS	2015	100.0	-	100.0

Energy Probe (EP) INTERROGATORY #62 List 1

Issue 22 Are the OM&A and capital amounts in the Green Energy Plan appropriate and based on appropriate planning criteria?

Interrogatory

Ref: Exhibit A, Tab 14, Schedule 1, Page 7 &
Exhibit D1, Tab 3, Schedule 3, s.2.2.5

The first reference mentions “administrative systems are being put in place to obtain fair recovery from the generators”. The second reference details a plan to spread costs over multiple generators as they connect to the system. The main element of the plan appears to be a process to refund some of the costs charged to the first generator to cross the threshold for protection upgrades as subsequent generators attach to the circuit.

a) Line 25 states that “these costs will be prohibitive to smaller generators”. If a smaller generator triggers the need for protection upgrades what accommodation will Hydro One make to ensure that the cost allocation process does not cause a the generator to delay or cancel its project?

b) If subsequent generators have not been identified at the time the protection upgrades are triggered, how can the threshold crossing generator be assured that it will ever recover some of the costs allocated to it? Will this cause projects to be delayed or cancelled?

Response

a) Hydro One must follow the requirements of the Transmission System Code in allocating costs to connecting generators. Hydro One apportions the protection upgrade costs among benefiting generators in accordance with section 6.3.14 of the Code. Hydro One also provides refunds to connected customers in accordance with section 6.3.17 of the Code. Although the refund measure is expected to help mitigate the cost burden to small generators, it does not alleviate the requirement for the small generator to initially provide the funds to pay for transmission costs that can be many times the cost of their project.

b) If subsequent generators have not been identified at the time the protection upgrades are triggered, Hydro One proposes that it would be difficult for the threshold crossing generator to ever be assured that it will recover any of the costs allocated to it. As a consequence, there is the possibility that proponents may decide to delay or cancel these projects.

Energy Probe (EP) INTERROGATORY #63 List 1

Issue 22 **Are the OM&A and capital amounts in the Green Energy Plan appropriate and based on appropriate planning criteria?**

Interrogatory

Ref: Exhibit A, Tab 14, Schedule 1, Page 7 &
Exhibit D2, Tab 2, Schedule 3, Page 82

Line 25 of the first reference refers to Enhanced Transfer Trip Facilities and notes that they are not essential to allow generators to connect to the system but may be desirable to permit generators to continue operating during some kinds of outages. Project D26 describes the enhanced facilities and notes that the three different groupings of costs should be recovered from the generators benefiting from them.

a) Is there a potential for free ridership if one generator requests the enhanced facilities and other generators do not?

b) How will costs be apportioned between generators benefiting from the enhanced facilities?

Response

a) Yes, there is the potential for free ridership. The facilities, once installed for one generator, will benefit others with relevant connection topology.

b) Hydro One will apportion the costs among generators in accordance with the Transmission System Code. Under the Code, the generators that initially request the enhanced facilities are charged for the full cost of those facilities. In cases where a subsequent connecting generator requests the enhanced transfer trip, the refund mechanism would be applied, as per section 6.3.17 of the Code. However, as it is impossible to know whether a subsequent generator would have requested the enhanced facilities in cases where the enhanced facilities were already requested (and paid for) earlier, the normal refund provisions of the Code cannot be relied upon to ensure fairness in apportioning the costs, with respect to the user pay principle. Hydro One notes that this could have the effect of incenting generators in some cases to delay their connections in the hopes of avoiding such costs. Finally, Hydro One notes that it is possible for this free ridership issue to also arise even among generators connecting at the same time, under the current rules.

Energy Probe (EP) INTERROGATORY #64 List 1

Issue 22 Are the OM&A and capital amounts in the Green Energy Plan appropriate and based on appropriate planning criteria?

Interrogatory

Ref: Exhibit A, Tab 14, Schedule 1, Page 8 &
Exhibit D2, Tab 2, Schedule 3, ISD D23

These references are concerned with a project to install a sectionalizing station necessary to incorporate the proposed Armow Wind Generation Connection project in the Kincardine area. The investment summary document states that the "cost of the sectionalizing station will be pool funded consistent with Proceeding EB-2010-0002 for in-line circuit breaker projects as it is system driven and provides system benefits"

a) In its Decision with Reasons in EB-2010-0002 the Board approved two in-line circuit breaker projects but declined to "provide any guidance to the company in respect to … four of the in-line circuit breakers". Is project D23 one of the two approved by the Board in the above referenced decision?

b) If not, please explain why Hydro One is assuming that the cost will be "pool funded consistent with Proceeding EB-2010-0002 for in-line circuit breaker projects".

c) From the D23 project document, it appears that the project is required solely to incorporate a new wind farm. Why does Hydro One conclude that it is "system driven and provides system benefits".

d) What are the system benefits referred to in the project document?

e) If the new wind farm did not proceed, would Hydro One still require the sectionalizing station?

Response

a) Project D23 Armow Wind Generation Connection is not one of the two in-line breaker projects approved by the Board in proceeding EB-2010-0002. However, as outlined in the updated evidence filed on August 15th, 2012 the need for in-line breakers to sectionalize and tap the existing 230kV circuit is no longer required for this generation connection. The cost estimate for the project has been revised to reflect this reduction in scope, please see Exhibit D1, Schedule 3, Tab 3, Appendix A, Table 5.

b) Not applicable
c) Not applicable

d) Not applicable

e) Not applicable

Energy Probe (EP) INTERROGATORY #65 List 1

Issue 22 Are the OM&A and capital amounts in the Green Energy Plan appropriate and based on appropriate planning criteria?

Interrogatory

Refs: Exhibit A, Tab 14, Schedule 1, Page 11 &
Exhibit D1, Tab 3, Schedule 3, Page 30

According to the first reference at lines 5-6 on Page 11, these projects are required to address the consequences of generation already connected to the system and the second reference at line 14 concludes that the costs will be allocated to the network pool.

a) Why should these costs be recovered from ratepayers when they appear to be a direct consequence of generators attaching to distribution and transmission systems?

b) Some or all of these costs appear to have been unforeseeable at the time renewable generators started connecting to the distribution and transmission systems. Now that Hydro One has experience with the consequences of these connections, why shouldn't it levy a charge against all new generators to offset the foreseeable costs of necessary protection modification in the future?

Response

a) Of the three items listed on page 11 of Exhibit A, Tab 14, Schedule 1, two are for maintaining the correct operation of schemes that are in place for the reliability of the transmission system. These investments are needed to accommodate changing load and generation patterns across the system. They are not attributable to any particular generators and become necessary only after an aggregate of load and/or generation changes have taken place at the distribution level. Hydro One submits that these costs should be pooled as they are driven primarily by system needs and not by the needs of any specific customers.

The third item, pertaining the mitigation of power distance limitations was approved for pool funding in the previous EB-2010-0229 proceeding.

b) As stated in part a), these investments are needed to accommodate changing load and generation patterns across the system. For this reason, Hydro One believes it would be both impractical and inappropriate to allocate these costs to specific generators.

It is a fact that some expenditure on the transmission system will always be required due to the incremental effects of many connected customers, both load and generation, which aggregate over time resulting in a sufficient material impact that triggers the need for upgrades or modifications. Certain types of Network Pool investments, such as capacitors and reactors, already fall into this category.

Energy Probe (EP) INTERROGATORY #66 List 1

Issue 22 Are the OM&A and capital amounts in the Green Energy Plan appropriate and based on appropriate planning criteria?

Interrogatory

Ref: Exhibit C1, Tab 3, Schedule 3, Attachment 1 - Smart Grid Development Plan

This exhibit discusses research and development projects undertaken in 2011 and 2012 to support smart grid development. Many projects were undertaken in conjunction with various Ontario Universities, governments and international standards organizations. Absent from the discussion are any results from the projects. Please provide an analysis of the projects completed in 2011 focusing on results and their application to the development of the smart grid.

Response

An analysis of the 2011 projects focusing on results and applications are detailed below;

1) Ontario University Program:

   As outlined in Exhibit C1, Tab 3, Schedule 3 it entails multi-year partnership programs with Ontario universities to assess, evaluate and confirm the viability of emerging technologies, products and approaches related to power systems.

   - University of Waterloo-Wise (Waterloo Institute of Sustainable Energy) has undertaken several studies to focus on modeling and optimization of Distributed Generation connections related to fuel mix; assessment and mitigation of Power Quality issues; and development of sustainable Energy Hubs in collaboration with external partners and Ontario Centre of Excellence.

   - University of Western Ontario research has focused on Power System protection, control and communication aspects with results that support the Transmission Station infrastructure and Hydro One's Smart Grid. The Solar integration project completed in 2011 has resulted in novel applications and patents to maximize the connection of distributed generation facilities and potentially increase the transmission capacity.

   - Ryerson University-UCE (Urban Energy Centre) has undertaken studies in micro-grids and energy storage, and intelligent control systems for integration of Wind and Solar generation in support of the Smart Grid evolution. Additional studies include assessments in the reduction of Carbon Footprint at Hydro One, implementation of clean energy initiatives with potential to mitigate the burden of air conditioning loads on electrical grid, and assessments of the potential impact of electric vehicles on Greater Toronto Area grid infrastructure.

2) Energy Storage Project:

As outlined in Exhibit C1, Tab 3, Schedule 3 this is a multi-year partnership project. In 2011 the focus of this project was on the assessment and development of large scale Lithium-Ion storage technology and the identification of performance requirements of a prototype fabrication for potential application to transmission systems.

This applied research will allow a large scale performance testing and validation of the storage technology with focus on support of the grid voltage in order to mitigate issues of Distributed Generation intermittency.

3) CEATI Program:

As outlined in Exhibit C1, Tab 3, Schedule 3 this is also another multi-year program. In 2011 the focus was on intelligent devices and applications to improve system performance, reliability and power quality for the transmission system. Results of this research will allow reinforcement, enhancement and utilization of the transmission system infrastructure and manage integration of renewables in support of smart grid evolution.

4) Large Scale PV Integration:

As outlined in Exhibit C1, Tab 3, Schedule 3 this was a 3 year partnership project undertaken in collaboration with the industry partners and Ontario Center of Excellence that concluded in 2011. The project produced multiple novel applications and patents which will support Hydro One’s grid infrastructure allowing increased connections of renewable generation as well as maximum utilization of interface devices which will potentially emulate storage devices.

5) Inverter Performance:

This research is part of a two year term study initiated in 2011, and focuses on assessment, evaluation and performance testing of commercially available inverter devices deployed in a number of renewable generation facilities. The results of this research are expected to provide Hydro One with the knowledge to potentially mitigate the impact generators have on power quality as well as development of standards criteria which may be applied in evaluation of future renewable generators.

6) Relay Alternative:

This project was undertaken in 2011 to focus on assessment and evaluation of protection and control options for renewable generation facilities. The result of the study identified a potential cost effective protection approach to isolate renewable generators, which may be applicable under specific circumstances based on the grid configuration, in support of the Smart Grid evolution.

School Energy Coaliton (SEC) INTERROGATORY #40 List 1

Issue 22 Are the OM&A and capital amounts in the Green Energy Plan appropriate and based on appropriate planning criteria?

Interrogatory

[A-15-6/p.3]
Please provide the findings of the Owen Sound smart grid pilot project.

Response

As noted in Exhibit A, Tab 15, Schedule 6, page 3, the Owen Sound smart grid pilot project is still underway. Findings are not yet available.

Association of Major Power Consumers in Ontario (AMPCO) INTERROGATORY #12 List 1

Issue 22 Are the OM&A and capital amounts in the Green Energy Plan appropriate and based on appropriate planning criteria?

Interrogatory

Ref: A-14-1, Page 2, lines 6 – 9

a) Please provide a summary of the planning work by Hydro One, the OPA and the Ministry of Energy and Infrastructure related to renewable initiatives since Hydro One' last Transmission Rate Application (EB-2010-0002) to the present. Please include a summary of the ongoing work by the three parties.
b) Please provide any written correspondence between the above parties.

Response

a) Since Hydro One's last rate submission, both the OPA and Hydro One have conducted significant planning work on projects related to renewable initiatives. Hydro One has been working with the OPA on the planning and development of two priority projects in the governments Long Term Energy Plan, namely the installation of a SVC at Miton SS and the reconductoring of the Lambton TS to Longwood TS 230kV circuits (development projects D5 and D6 respectively). The OPA has provided supporting evidence for the installation of a SVC at Milton (as documented in Exhibit D1, Tab 3, Schedule 3, Appendix C), as well as supporting evidence in the Leave to Construct application of the Lambton TS to Longwood TS (EB-2012-0082) filed by Hydro One.

   The third priority project in the LTEP is primarily for the purpose of incorporating additional renewable generation and involves a new transmission line west of the London area. This project is currently being studied by the OPA.

   Hydro One is also actively planning for the connection of 37 FIT and 12 non-FIT renewable generators to the Hydro One transmission system. On March 1, 2011, the government directed the OEB to amend Hydro One's Transmission License to upgrade up to 15 transformer stations to facilitate the connection of small scale generation. Subsequently, Hydro One worked with the OPA, to identify the stations to be upgraded and following the April 7, 2011 letter from the OPA, Hydro One has conducted the planning and development for the upgrades and is in the process of implementing this work.

In addition, Hydro One has conducted the required planning work related to protection and control upgrades needed to connect renewable generators to the distribution system.

b) Please refer to Exhibit A, Tab 14, Schedule 1, Appendix C and Exhibit D1, Tab 3, Schedule 3, Appendices C and D for correspondence related to some of the planning work described above.

Association of Major Power Consumers in Ontario (AMPCO) INTERROGATORY #13 List 1

Issue 22 Are the OM&A and capital amounts in the Green Energy Plan appropriate and based on appropriate planning criteria?

Interrogatory

Ref: A-14-1, Page 4, lines 6-9

a) Please provide copies of the studies Hydro One is relying on to support this statement.

Response

a) To clarify the referenced statement, Hydro One is not aware of any studies or assessments by Hydro One, IESO or the OPA that has identified a specific need for any of these projects to date.

<u>Association of Major Power Consumers in Ontario (AMPCO) INTERROGATORY #14 List 1</u>

Issue 22 Are the OM&A and capital amounts in the Green Energy Plan appropriate and based on appropriate planning criteria?

<u>Interrogatory</u>

Ref: A-14-1, Page 4, lines 22-24

a) Please provide an update on the small scale and larger size distributed generation and also medium and large sized transmission connected generation connections expected in the central and downtown areas of Toronto.

<u>Response</u>

a) Please refer to Toronto Hydro's "THESL 2012 GEA Plan" document in proceeding EB-2011-0144 Exhibit G1, Tab 2, and Schedule 2, Section 3.1.1 for details on the expected distributed connection generation in the downtown area of the City of Toronto.

At this time, Hydro One is only aware of one project at 50MW expressing an interest in connecting at the transmission level in central and downtown Toronto.

Association of Major Power Consumers in Ontario (AMPCO) INTERROGATORY #15 List 1

Issue 22 Are the OM&A and capital amounts in the Green Energy Plan appropriate and based on appropriate planning criteria?

Interrogatory

Ref: A-14-1, Page 5

a) Please explain the increased costs for the turn-key GIS station and the increased costs for P&C facilities.
b) Please explain why the property purchase negotiations took longer than expected.
c) Please confirm the expected in-service dates for lSD# D7, D8 and D9.

Response

a) The cost of $84.9M provided in Proceeding EB-2010-0002 was based on preliminary scopes and estimates. Since the last filing: (i) an open tender was undertaken for the turn-key GIS station. The cost for the contracted work came in $12M higher than originally forecasted in the preliminary estimate; (ii) detailed engineering commenced and revealed that protection modifications and removal work was more extensive than initially anticipated resulting in a $7M cost increase.

b) Property acquisition was delayed due to concerns of electrical grounding issues by the property owner. Additional grounding studies were required to satisfy the property owner before the purchase could be completed.

c) The expected in-service dates for Project D7 and D8 is Q4 2014, and for Project D9 is Q4 2013 as outlined in Exhibit D1, Tab 3, Schedule 3, Appendix A, Table 3 updated on August 15th, 2012.

<u>Association of Major Power Consumers in Ontario (AMPCO) INTERROGATORY #16 List 1</u>

Issue 22 Are the OM&A and capital amounts in the Green Energy Plan appropriate and based on appropriate planning criteria?

<u>Interrogatory</u>

Ref: A-14-1, Page 9, lines 11- 14

a) Please provide a detailed breakdown of the costs that make up the $1 million expenditures.

<u>Response</u>

a) Lines 11-14 of the referenced exhibit does not refer to such expenditures. However, we assume that AMPCO was referring to lines 15-18 instead of 11-14.

The $1M expenditure is a preliminary estimate and a detailed breakdown is not available at this time. However, this expenditure level is typical for projects similar in magnitude and at this early stage of potential development.

These expenditures would be for project development work to support the Ontario Power Authority (OPA) to develop and screen transmission options. Such development work can include: technical studies, preliminary work to identify suitable corridors, conceptual level engineering, preliminary environmental screening work, real estate work to identify potentially impacted land owners, and initial consultation work with potentially affected stakeholders including municipalities and first nations.

Association of Major Power Consumers in Ontario (AMPCO) INTERROGATORY #17 List 1

Issues 22 Are the OM&A and capital amounts in the Green Energy Plan appropriate and based on appropriate planning criteria?

Interrogatory

Ref: A-14-1, Page 14, Lines 21-24

a) Please provide a detailed description and breakdown of costs for the development work that Hydro One out sourced.

Response

a) During 2010 Hydro One outsourced the following services while developing the transmission projects in support of renewable energy projects:

- Engineering: Conceptual engineering, development of options and study level cost estimates and mapping.
- Environmental: Early stages of the environmental assessment process as required by the EAA and includes customer consultation.

The following is a breakdown of the costs associated with the out sourced work;

Engineering	$1.5M
Environment	$0.9M
Total	$2.4M

Association of Major Power Consumers in Ontario (AMPCO) INTERROGATORY #18 List 1

Issues 22 Are the OM&A and capital amounts in the Green Energy Plan appropriate and based on appropriate planning criteria?

Interrogatory

Ref: A-14-1, Page 16, line 10

a) Please provide a detailed description and breakdown of the $4.6 million costs and show the division of work between internal labour and contract work.

Response

a) For a description of contract work, please refer to Exhibit I, Tab 22, Schedule 13.06 AMPCO 17.

During 2010, internal labour included project management, conceptual engineering and development of options, cost estimates and environmental assessment of the study area including customer consultation. Much of this work was in concert with the contractors.

Breakdown of Green Energy Project Costs ($M)

Project Name	Internal Labour	Contract Work	Other	Total
Goderich Area Enabler	0.1	0.1	-	0.2
Northwest Transmission Line	0.6	0.7	0.1	1.4
Manitoulin Island Enabler Line	0.1	0.1	-	0.2
East-West Tie TX Development	0.2	0.2	-	0.4
North South Transmission Expansion	0.4	0.8	-	1.2
Hamner x Mississagi	0.2	0.3	-	0.5
West of London TX Line Development	0.3	0.2	0.2	0.7
Total	**1.9**	**2.4**	**0.3**	**4.6**

Association of Major Power Consumers in Ontario (AMPCO) INTERROGATORY #19 List 1

Issue 22 Are the OM&A and capital amounts in the Green Energy Plan appropriate and based on appropriate planning criteria?

Interrogatory

Ref: D1-3-3 Appendix A, Page 3

a) Please provide the 2012 Year to Date totals for projects 07, D8 and D9.

Response

a) Please see the following table for the 2012 Year-to-Date Gross actual expenditures (as of June 30, 2012) for Projects D7, D8, and D9.

ISD#	Investment Description	YTD June 2012 Gross Cost ($M)
D07	Toronto Area Station Upgrades for Short Circuit Capability: Leaside TS Equipment Uprate	4.5
D08	Toronto Area Station Upgrades for Short Circuit Capability: Manby TS Equipment Uprate	0.9
D09	Toronto Area Station Upgrades for Short Circuit Capability: Re-build Hearn SS	4.8

Ontario Energy Board (Board Staff) INTERROGATORY #84 List 1

Issue 23 What is the appropriate level for Export Transmission Rates in Ontario?

Interrogatory

Ref: Exhibit H1-5-2/Appendix B/p 8

In the 6th bullet point on this page, it is noted:
"None of the tariff changes studied has a material impact on the volume of baseload exports during the SBG periods;"

a) It is Board staff's understanding that exports are undertaken during SBG periods, in part, to maintain reliability of the Ontario grid. Does the above imply that there is therefore no impact on reliability of the Ontario grid under different export tariffs?

b) Is the reason that there is little effect on exports under the various rates because the level of exports is constrained by the capacity of the interties, as shown in Appendix E at p. 56? If there are other reasons, please explain.

Response

a) There is no potential impact on reliability of the Ontario grid under different export tariffs.

b) There is little impact on baseload exports. The reason for this, as stated on page 22 of the same reference, is that "the differentials in baseload variable costs between Ontario sources and US baseload generation, which is mainly coal based, are so large that none of the proposed tariff changes would alter export decisions during SBG events". Moreover, sensitivity analyses were run with varied intertie capacities during low-load periods. The conclusion from these analyses is that the export tariff itself does not impact the level of SBG, regardless of the intertie capacity assumption.

Ontario Energy Board (Board Staff) INTERROGATORY #85 List 1

Issue 23 What is the appropriate level for Export Transmission Rates in Ontario?

Interrogatory

Ref: Exhibit H1-5-2/Appendix B/p 10
In the first paragraph on this page, it is stated:

"Charles River Associates ("CRA") was engaged by the Ontario Independent System Operator ("IESO") to perform an analysis of four different Export Transmission Service ("ETS") tariff scenarios for the years 2013, 2015 and 2017."

a) Who picked the tariffs to be modelled and how were they determined?

b) Was reciprocity with the connected regions considered as a tariff? i.e. charging the exporter at the interconnection the exact fee that an importer at the connection would be charged.

i. If so, why was it not modelled?
ii. If not, why not?

c) Appendix B, page 49 (Page 40 of the study) footnote # 11 mentions the study "Review of Rates in Neighbouring Markets". Is this study included in the record of this proceeding, or a previous proceeding? If neither, please provide this study.

Response

a) The ETS study approach and methodology, including various tariff options, were discussed as part of the IESO's Export Transmission Tariff Study Stakeholder Engagement (SE-94) process. The specific tariff options studied and modeled by CRA were selected as the result of that process. The selection of the tariff options is documented in the meeting minutes from SE-94. Please refer to Attachment 2 of this Interrogatory for the document.

b) As indicated in answer a) above, the tariff options were selected as part of SE 94. Reciprocity with connected regions was not selected as an option to be studied. As noted in Hydro One's 2011-12 rate proceeding EB-2010-0002, reciprocity requires the agreement of all neighbouring jurisdictions and in the past few neighbouring jurisdictions have expressed interest.

c) The “*Review of Rates in Neighbouring Markets*” is not included in the record of this proceeding or in a previous proceeding. Please refer to Attachment 1 of this Interrogatory for the study.

CRA Charles River Associates

Export Transmission Service Tariff Study

Review of Rates in Neighbouring Markets

Prepared for:

The Independent Electricity System Operator

May 16, 2012

Table of Contents

1. Executive Summary

Charles River Associates (CRA) was retained by the Independent Electricity System Operator (IESO) to conduct a review of export transmission tariff designs and rates in the electricity markets adjacent to Ontario as part of an evaluation of potential export tariff rates and structures.

This study considers five electricity market jurisdictions in the United States (US) and Canada, namely the New York ISO (NYISO), Pennsylvania-New Jersey-Maryland (PJM) ISO, ISO New-England (ISO-NE), Midwest ISO (MISO) and TransÉnergie in Québec. In each of these jurisdictions a single entity is responsible for providing transmission services to market participants, for collecting transmission service charges and for allocating the collected transmission revenues to the various transmission owners whose transmission facilities make up the combined transmission grid. The information presented in this report was obtained through a review of the Open Access Transmission Tariffs (OATT) posted by each of the above jurisdictions on their respective websites and where necessary through telephone discussions.

The essence of the current study is to review how export transmission tariffs are determined, to provide comments on any significant changes that have taken place over the last five years, and to report the numerical values for charges applicable to export service.

Table 1.1 below summarizes the 2011 rates in each jurisdiction for Firm Point-to-Point (PTP) Export Transmission Services (ETS). Also shown for comparative purposes is the approved ETS tariff for Ontario. The rates are provided on an annual, monthly, weekly and daily basis and are shown in Canadian dollars.[1] Please see Section 5 of this report for the definition of the different rate periods indicated in the table. It should be noted that $/kW rates are capacity-type tariffs (used in PJM, ISO-NE, MISO, TransÉnergie), i.e., they are assessed on the basis of reserved capacity, whereas $/MWh rates are usage (energy) type tariffs (used in NYISO and Ontario), assessed on the basis of energy scheduled or transmitted. A capacity-based tariff may be converted to a volume based tariff making certain assumptions about usage.

[1] The average rate of exchange during 2011 was C$1.0 = US $1.0117; Source: Bank of Canada.

TABLE 1.1 - SUMMARY OF FIRM POINT-TO-POINT TRANSMISSION RATES FOR EXPORT TRANSMISSION SERVICE					
	ANNUAL SERVICE $/kW-year	**MONTHLY SERVICE $/kW-month**	**WEEKLY SERVICE $/kW-week**	**DAILY ON-PEAK SERVICE $/kW-day**	**DAILY OFF-PEAK SERVICE $/kW-day**
MISO	29.3756	2.4480	0.5649	0.1130	0.0805
PJM	18.6696	1.5558	0.3590	0.0718	0.0513
NYISO	The energy-based rate for the Firm PTP service is different for each transmission company at the seam of NYISO, and it ranges between $2.9233 per MWh to $5.5056 per MWh.				
ISO-NE[2]	63.135				
TransÉnergie[3]	72.45	6.04	1.39	0.28	
Ontario	Energy based rate currently set at $2/MWh				

It should be noted that bilateral exemptions to reduce inter-market PTP transmission charges to zero have been agreed to and implemented between NYISO and ISO-NE and between PJM and MISO.

Export Transmission Service may also be provided as a Non-Firm PTP transmission service, which is also available in each of the jurisdictions considered in this study. This Non-Firm service is available on a monthly, weekly, daily, and hourly basis (see Section 5 for how these rate periods are derived). The primary difference between Firm and Non-Firm services is that export transactions using the latter are the first be recalled or curtailed by the ISO at any time and at its discretion, for example, when outages reduce transfer capability, or when power backed by installed capacity is called by the receiving ISO under shortage conditions. The rules that specify the circumstances under which an ISO may recall Non-Firm service vary from ISO to ISO.

The nominal rates for Non-Firm PTP service are generally similar or identical to the corresponding rates for the Firm PTP service for the same duration; Section 5 provides more detail to that effect. An ISO may, however, offer discounts on these nominal rates. The current study generally supports previous observations made in the 2006 R.J. Rudden (Rudden) Report[4] that discounting occurs infrequently and is not prevalent in most ISOs.

[2] ISO-NE does not distinguish between Firm and Non-Firm transactions and does not offer monthly, weekly or daily transmission services. It offers hourly transmission service and this is noted in Table 5.1 of Section 5 of this report.
[3] TransÉnergie offers the same daily transmission service irrespective of time of day.
[4] "A Jurisdictional Survey of Export and Wheel-through Service Rates", R.J. Rudden, June 26, 2006.

2. Introduction

Background

As part of its decision in proceeding EB-2010-0002[5], the Ontario Energy Board (OEB) directed the Independent Electricity System Operator (IESO) to undertake a comprehensive study to identify a range of proposed Export Transmission Service (ETS) tariffs and their pros and cons. The range of proposed tariffs to be examined was identified through the IESO's stakeholder engagement process[6]. The data provided in this report serves two purposes: 1) to support modeling of export transactions with each neighbouring market for each identified ETS tariff structure/rate; and 2) to provide comparable data for the assessment of the proposed rates/rate structures for consistency with rates/rate structures in adjacent markets. As part of its response to its directions from the OEB, the IESO requested a review of tariff designs and rates in electricity markets adjacent to Ontario, and a summary of how those tariffs are determined[7]. CRA has carried out this review in order to provide an up-to-date set of factual data pertaining to ETS rates and related information with respect to ETS transactions in selected jurisdictions around Ontario. In this respect, the following five transmission providers were selected for the purpose of this study:

- The PJM Interconnection (PJM)[8]
- The New York Independent System Operator (NYISO)[9]
- The Independent System Operator of New England (ISO-NE)[10]
- The Midwest Independent System Operator (Midwest ISO), including the province of Manitoba[11]
- TransÉnergie (the transmission affiliate of Hydro Québec)[12]

Table 2.1 below provides a high level summary of the key statistics for each one of these jurisdictions. For comparative purpose information is also provided for Ontario.

[5] EB-2010-0002 – Hydro One Networks Inc., "2011 and 2012 Transmission Revenue Requirement and Rate" - OEB Decision with Reasons, December 23, 2010.
[6] Export Transmission Service Tariff Study (SE94), IESO, 2011.
[7] Export Transmission Service Tariff Study, IESO Request for Proposal, October 7, 2011.
[8] www.pjm.com (PJM OATT).
[9] www.nyiso.com/public/markets (NYISO OATT).
[10] www.iso-ne.com (ISO-NE OATT).
[11] https://www.midwestiso.org/Library/Tariff/Pages/Tariff.aspx.
[12] www.oatioasis.com/HQT/HQTdocs/OATT_2011.pdf.

TABLE 2.1 - KEY STATISTICS							
	UNITS	MISO	PJM	NYISO	ISO-NE	TransÉnergie	ONTARIO
Generating Sources	#	1181	1365	291	>350	60	61
Generating Capacity	MW	145,966	164,895	40,685	32,000	36,671	34148
Peak Demand	MW	108,904	163,848	33,452	28,130	37,717	25,450
Transmission Owners	#	35	>65	8	>25	1	4
Transmission Line Length	km	92,459	90,924	17,530	13,084	33,453	29,631
States/Provinces Served	#	13	14	2	6	1	1
Customers/Population Served	Million	40	51	19	14	4	5
Area Served	Km^2	1,980,443	436,389	126,757	176,110	1,541,971	681,680
Market Participants	#	>300	>750	~397	400	n/a[13]	242

The provision of equal access to transmission services is now well established throughout the various electricity markets in the US and Canada that are administered by the respective ISOs. Furthermore, in the interest of improving the efficiency of the electricity markets, rate pancaking[14] between adjacent markets for some jurisdictions has been eliminated as per Federal Energy Regulatory Commission (FERC) requirements[15] and as noted in the Rudden report. Notably agreements to reduce transmission service charges to zero for inter-market transactions are in place between NYISO and ISO-NE, and between PJM and MISO. However, only inter-market transmission service charges *per se* have been eliminated in those agreements, while ancillary service and market administration charges applicable to export transactions remain in place.

Scope of Study

In reviewing the transmission tariff designs and ETS rates used in the above jurisdictions CRA examined the following topics:

- Transmission services offered in each jurisdiction;
- Rates for the provision of Firm and Non-Firm ETS, and the method used to derive ETS rates;

[13] Although there are a number of independent power producers in Québec, there is not a centrally-coordinated market *per se* as in the regions with ISO/RTOs.
[14] Rate pancaking refers to the cumulative addition of transmission service charges for electricity transactions that cross over several different transmission zones, each of which has an approved transmission tariff, between the point of initiation of the transaction and the point of termination of the transaction.
[15] FERC Order No. 2000.

- Rate surcharge adders that may be applicable, in addition to the nominal ETS rates in those jurisdictions, and how the revenue from such adders is distributed among the transmitters, and;
- Discounting provisions, if applicable, to ETS Rates.

All rates in this Report are presented in Canadian dollars. Rates for US jurisdictions were converted in this report at $CAN 1.00 = $US 1.0117, this being the average exchange rate during 2011[16].

The purpose of this study is to provide a succinct summary of the findings by combining the information gathered from each of the above jurisdictions to create an overall view from the perspective of how transmission service is provided, how rates are determined and how ETS rates are derived from those transmission rates. To this end, Section 3 of this report provides a summary of the general nature of transmission services in each jurisdiction, while Section 4 provides a summary of the main characteristics of ETS services offered in each jurisdiction. Section 5 provides a summary of how the ETS rates are determined in each jurisdiction. Finally, Section 6 concludes with some remarks on the review carried out in this study. Appendices I through V provide additional detail on transmission rates and rate adders for each jurisdiction.

[16] Source - Bank of Canada.

3. Transmission Services

The markets administered by the US ISOs are typically served by a transmission grid that is comprised of transmission facilities that are owned by several different transmission companies. In each case the transmission owners need to recover their approved revenue requirement. At the same time, in order to ensure market efficiency within a single marketplace, costs for transmission services are recovered in a way that avoids "pancaking" of charges, i.e., where transmission owners charge cumulatively for energy transactions flowing over their respective transmission facilities. In Canada, the Ontario grid is owned by multiple companies--with Hydro One owning about 97% of Ontario transmission assets--and TransÉnergie (in Quebec) and Manitoba Hydro (in Manitoba) are the only transmission service providers in their respective provinces. Whereas TransÉnergie is solely responsible for administering transmission services and collecting transmission revenues from market participants in Quebec, MISO administers and settles the transmission services on behalf of Manitoba Hydro as the latter is a member of MISO and has signed a coordinating agreement with MISO to that effect[17].

In general, when market participants who are located in, and operate within, each of the above jurisdictions, they are required to take network transmission service and pay a corresponding Network Service charge, designed to recover the transmission owners' approved net annual transmission revenue requirement. Network Service (also known as Network Integration Service) covers the transmission facilities that collectively make up the transmission grid that is operated by an ISO and which enables the seamless transfer of electricity from a variety of designated generation sources scattered across the integrated system to a variety of load (demand) centres located within the single market.[18] In this respect, Network Service charges recognize the fact that transmission facilities are provided to serve native load[19] within the transmission grid and as such these load serving entities should have the responsibility to pay their fair share of the costs of those facilities. To the extent that the same transmission

[17] Manitoba Hydro – Open Access Transmission Tariff Business Practices Manual.

[18] Network service typically also provides for designated network resources outside a market area to serve network load inside the area, although this is not a prevalent use of the service.

[19] Native load is widely understood to mean a transmission owner's or ISO's own load, vs. e.g., transmission load, which may include PTP transmission customers.

facilities are used to provide other than Network Service, ratepayers who pay for the embedded costs of the transmission facilities within a single market should benefit from contributions to transmission revenue requirements that accrue from charges for transmission services other than Network Service. Indeed, the typical tariff design for U.S. and Canadian transmission owners is that the Network Service rate is designed to recover the transmission owner's annual net revenue requirement, which is calculated as the annual gross revenue requirement less revenue from non-Network Service transactions.

Typically a system of Network Service charges is applicable to transactions within a given ISO's market jurisdiction, which may span multiple transmission owners. This can be done using either "postage stamp" or "license plate" rate structures. Under a postage stamp rate structure, every transmission customer pays a single rate for any transmission transaction within a defined region, regardless of the contractual origin and contractual destination of the electricity transmitted. That rate is the same for every customer. Under a license plate rate (also called zonal rate) structure, every transmission customer pays a single rate for any transmission transaction within a defined service territory, regardless of the contractual origin and contractual destination of the electricity transmitted, as with a postage stamp rate. Unlike the postage stamp rate, however, the license plate rate is not the same for every customer in the region. Instead, each customer's rate reflects the cost of transmission facilities within that customer's service territory.

Most US ISOs included in this report use license plate rate structures. The one exception is the New England market, where in addition to zonal transmission rates a pool transmission rate (postage stamp) is also applicable. In all cases the corresponding transmission charges ensure that the respective transmission owners recover the approved net transmission revenue requirements. For the most part, transmission Network Service charges are generally levied on a long-term basis, i.e. annual or longer periods, which is typically associated with serving the embedded or native load customers in each jurisdiction. In Canada, TransÉnergie uses postage stamp rates, as does Ontario.

Under the FERC's (and Régie de l'énergie in Québec) pro forma Open Access Transmission Tariffs (OATT), Network service is deemed a Firm category of service, in that all users who pay for this service are assured of continuous access to all resources to meet their load requirements without undue discrimination. In this respect those who pay for this service have top, and equal, priority in obtaining access. It is this Network Service charge that is for the most part used as the starting point for deriving the Non-Network Service charges (Please see Section 5 of this report).

4. Export Transmission Services

Electricity market participants also make use of non-network transactions (not involving integration of network resources to serve native load) which must also be scheduled over the same transmission systems that serve the native load customers in each marketplace. Typically these types of transactions allow market participants to transmit power from less expensive markets to those where the power is more valuable, or from a generator not located in one market jurisdiction to supply load customers located in a different market jurisdiction. These types of transactions may entail periods that are annual, monthly, weekly, daily or hourly. Such transactions typically make use of the so-called Point-to-Point (PTP) transmission service, of which ETS and/or Wheeling or "Through and Out" transmission services are particular examples.

PTP transmission service entails reserving service between a designated Point of Receipt (POR – generally associated with injection of electricity from generation resources) and a designated Point of Delivery (POD – generally associated with delivery of energy at a load centre). This service supports three types of transactions, namely

- **"Into," "In," or "Import" Transactions** - where external resources located in another market jurisdiction are scheduled to supply a load located within the receiving home market jurisdiction;
- **"Out" or "Export" Transactions** - where a given internal resource in a home market jurisdiction is scheduled to deliver to a load located in an external market jurisdiction; or
- **"Wheel Through" or "Through and Out" Transactions** - which originate outside the home market jurisdiction, pass through the home market jurisdiction and are destined for delivery into a third market jurisdiction

PTP transmission services can be Firm or Non-Firm. Firm PTP transmission services can be offered on an annual (or longer), monthly, weekly and daily basis, and these would have the same priority as Firm Network Service. Non-Firm PTP services are typically offered for shorter periods, e.g. monthly, weekly, daily or hourly, and have a lower priority than Firm PTP. The primary difference is that an ISO may, at its discretion, recall transactions using Non-Firm service, for example, when outages reduce transfer capability. Thus to a large extent, for ETS in an ISO market, Non-Firm PTP service differs from Firm PTP service in that Non-Firm service has a greater chance of being curtailed, and can be reserved by the hour20. Non-Firm PTP transmission service is available when there is available transmission capacity in excess of that needed for reliable service to an ISO's firm service customers, i.e., Network Service customers and customers taking Long-Term (duration of a year or longer) and Short-Term (less that year in duration) Firm PTP Service. Non-Firm PTP Service must be reserved, but scheduled transactions have lower priority than Firm Service transactions. For either Firm or Non-Firm PTP service, some ISOs provide for automatic or de facto reservation of transmission service when a transaction is scheduled. Table 4.1 below summarizes the PTP services in each jurisdiction reviewed herein in terms of those that are applicable to ETS.

TABLE 4.1 – EXPORT (PTP) TRANSMISSION SERVICE SUMMARY					
PERIOD	**MISO**	**PJM**	**NYISO Note 1**	**ISO-NE Note 2**	**TransÉnergie**
ANNUAL - FIRM	x	x		x	x
ANNUAL – NON-FIRM	x				
MONTH – FIRM	x	x			x
MONTH - NON-FIRM	x	x			x
WEEKLY – FIRM	x	x			x
WEEKLY – NON-FIRM	x	x			x
DAILY - FIRM	x	x			x
DAILY – NON-FIRM	x	x			x
HOURLY – NON-FIRM		x		x	x

Notes:

1. NYISO PTP transmission services are consumption based and so services based on different time periods don't have any meaning, i.e. there is no annual, monthly, weekly or daily service per se. However, NYISO offers both Firm and Non-Firm PTP services.
2. ISO-NE does not distinguish between Firm and Non-Firm transmission services.

In Ontario, the ETS provided to requesting market participants is not a PTP transmission service utilizing the concept of transactions between PORs and PODs, and there is no distinction between Firm and Non-Firm transactions. As per Section 4 of Chapter 10 of the Market Rules[21]

[20] For transactions internal to an ISO market, customers typically do not reserve transmission service, as all internal transactions are financial rather than physical.
[21] IESO Market Rules, Chapter 10 – "Transmission Service and Planning".

an exporting market participant is required to register with the IESO a boundary entity[22] to which the export transmission service will relate. The IESO determines the available transmission capability at each interconnection with a neighbouring transmission system for exports out of the IESO control area and manages congestion over such interconnections in accordance with the market rules. Exporters from Ontario whose transactions have been accepted by the IESO will be levied an ETS transmission charge based on the amount of energy scheduled for the corresponding boundary entity.

In most other markets, PTP transmission service requests are made through OASIS (Open Access Same Time Information System) and can be capacity based or usage (volume) based. Capacity based reservations entail reserving capacity with the ISO, where the said capacity reflects the maximum amount of capacity required to support the requested transaction. Once approved by the ISO, the market participant may schedule a transaction up to the approved capacity level.[23] PJM, ISO-NE, MISO and TransÉnergie offer this type of service for various term periods. Usage based PTP transmission service does not require capacity reservation and is based on the transaction MWh scheduled. NYISO offers such a usage-based PTP transmission service on a $/MWh basis only.

As a result of the need to improve the efficiency of inter-market transactions, FERC has mandated, to the extent practicable, that all inter-market transmission charges should be eliminated, thus removing the "pancaking" of rates which tends to discourage export or wheeling transactions. To date the NYISO and ISO-NE,[24] as well as PJM and MISO, have signed bilateral agreements to that effect.[25] Consequently inter-market transactions that are scheduled between NYISO and ISO-NE, and those scheduled between PJM and MISO, do not attract ETS transmission charges. As stated above, however, the elimination of rate pancaking

[22] Boundary entity means the capacity of one or more resources, including but not limited to generation facilities or load facilities, located at a point or points external to the IESO control area which a market participant is entitled to inject into or withdraw from the IESO-controlled grid and which shall be deemed to be located in an intertie zone in accordance with section 2.2.7.2 of Chapter 7; - Market Rules Chapter 11 – Definitions.

[23] In some cases (e.g., PJM), scheduling an import or export transaction also requires reservation of ramp space for time periods when the MW level of the transaction changes, such as when it starts or ends.

[24] The NYISO/ISO-NE agreement has been in effect since 2004.

[25] FERC Press Release, 11/18/04, Docket Nos. ER05-6-000, et al. and ER04-375-007 "Key Ruling Furthers Midwest ISO, PJM Integration, Proposal Boosts Electric Market Efficiency".

does not apply to Ancillary Service or Market Administration Service charges. Discussions have been ongoing between NYISO and PJM since 2005 but to date there is no agreement to eliminate ETS charges for inter-market transactions between these jurisdictions, although recent proposals are under consideration.[26] In addition, discussions are going on between ISO-NE and PJM regarding this subject matter.[27]

[26] http://www.nyiso.com/public/webdocs/committees/bic_miwg/meeting_materials/2011-07-18/CEE_proposal_for_NYISO_PJM_Export_Charges.pdf.
[27] www.iso-ne.com/regulatory/seams/2011/seams_current_2011-q2_7-8-2011.pdf.

5. Export Transmission Service Rate Design

Rate Design

PTP Service (ETS service) capacity rates ($/kW-period) are for the most part derived for the various terms of service (hourly, daily, weekly, monthly and in some cases annual) starting from the Firm Network Service rate and dividing that rate by the appropriate time portion of a year to obtain the different period rates[28]. In addition to the above term delineation, Daily and Hourly PTP services can also be distinguished into Peak and Off-Peak rates.

Typically the Network service rate is calculated as an annual rate whereby the transmission owners total annual transmission revenue requirement is divided by the annual peak demand served by that transmission owner's transmission system. Table 5.1 below summarizes the Firm and Non-Firm ETS service rates (in $C) provided in the various jurisdictions in 2011. Appendices I through V provide more detail of how those rates are arrived at for each jurisdiction. It should be noted that these transmission rates do not include Ancillary Services or Market Administration Services rates which will also be levied on ETS transactions in each jurisdiction.

The process used to calculate the transmission rates illustrated in table 5.1 has not changed from that described in the 2006 Rudden Report. The calculation process is governed by the FERC approved OATT requirements, and for the most part these calculation processes are similar across the jurisdictions. The principles that underlie these transmission charge calculations originate from FERC's Rate Orders 888[29], 889[30] and 2000[31] in which the common theme is the provision of non-discriminatory access to market participants using the

[28] Monthly Rate = Annual Rate /12;
Weekly Rate = Annual Rate/52;
Daily Peak Rate = Weekly Rate/5; or Annual Rate/260 (=5 x 52); (weekly peak period = 5 days);
Daily Off-Peak Rate = Annual Rate/365;
Hourly Peak Rate = Daily Peak Rate/16 or Annual Rate /4160 (=260 x 16); (daily peak period = 16 hrs);
Hourly Off-Peak Rate = Annual Rate/8760.

[29] FERC Order 888 - "Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities", April 24, 1996.

[30] FERC Order 889 – "Open Access Same-Time Information System (formerly Real-Time Information Networks) and Standards of Conduct", April 24, 1996.

[31] FERC Order 2000 – "Regional Transmission Organization", December, 29, 1999.

transmission systems of the various transmission owners operating within any given market jurisdiction. This led to the development of the OATT that specifies the terms and conditions under which access is obtained, and the methodology for calculating the corresponding transmission charges. The information required to develop these charges is submitted by transmission owners to FERC using a common format. Thus was established a standard format for the OATT and transmission charge calculations which continues to this day. The broad principles that fall out from this process are transparency, uniformity, non-discrimination and equal treatment for market participants, and reasonable expectation of cost recovery for transmission owners.

As indicated in the Rudden report, and continues to be the case today, there is commonality in the rate structures for the various term periods that might apply for an ETS transaction in most jurisdictions. The notable exception is the transmission rate applicable in the NYISO, which is a usage rate ($/MWh) rather than a capacity rate. As this is an hourly rate there is no need for specific term period consideration. Charges to transmission customers are determined by multiplying the amount of energy scheduled by the appropriate export transmission rate of which one component is specific to the given source and sink, as explained in Appendix III[32]. The NYISO rates shown in Table 5.1 represent the lowest and highest values in the range of actual transmission charges levied by the NYISO in 2011 to spot market export transactions, where the specific value depends on which neighbouring region the transaction is sinking.

Compared to the rates posted in the 2006 Rudden Report, the main changes appear in the MISO, ISO-NE and TransÉnergie rates, which have increased over 2006 values. In addition, the ISO-NE does not distinguish between Firm and Non-Firm transactions, as all scheduled transactions have the same priority. Furthermore, ISO-NE now only offers annual and hourly transmission services. Inasmuch as the basic transmission service rates developed by the Transmission Owners in NYISO based on their respective transmission revenue requirements

[32] For either spot market exports or wheel-through transactions, if the receiving control area is not adjacent to the New York Control Area, NYISO deems the sink to be the neighboring area that is next in the transaction path, for purposes of determining the applicable charges. For spot market exports, the source is deemed to be the NYISO Reference Bus; for wheel-through transactions, the source is the proxy bus for the prior adjacent control area in the transaction path

(and any applicable adjustments) and billing quantities have not changed from those discussed in the Rudden Report, the recognition that these rates are further adjusted by weighting factors to reflect source and sink locations is the main difference from the Rudden Report. The rates for the PJM jurisdiction are approximately the same as previously reported in the Rudden Report. Other than the NYISO, there do not appear to be any substantial changes in the form of the transmission charges, nor in the methods used to calculate them.

TABLE 5.1 – EXPORT (PTP) TRANSMISSION SERVICE RATE SUMMARY

	MISO		**PJM**		**NYISO**	**ISO-NE**[33]		**TransÉnergie**	
PERIOD	**Firm**	**Non-firm**	**Firm**	**Non-Firm**		**Firm**	**Non-Firm**	**Firm**	**Non-Firm**
ANNUAL $/kW-year	29.3756		18.669		**$2.9233/MWh - $5.5056/MWh**	63.135		72.45	72.45
MONTH $/kW-month	2.448	2.448	1.556	1.556				6.04	6.04
WEEK $/kW-week	0.5649	0.5649	0.3590	0.3590				1.39	1.39
DAY –Peak $/kW-day	0.1130	0.1130	0.0718	0.0718				0.28[34]	0.20[35]
DAY – Off-peak $/kW-day	0.0805	0.0805	0.0513	0.0513					
HOUR–Peak $/MWh		7.0608		4.4875		7.207			8.24
HOUR – Off-peak $/MWh		3.3531		2.1350					

(The shaded cells in the above table indicate that the specific term rates are not available in that jurisdiction.)

[33] ISO-NE does not provide time differentiated transmission services other than annual and hourly.
[34] In Québec the Firm and Non-Firm Daily rates do not distinguish between peak and off-peak periods.
[35] The same is also true for the Non-Firm hourly rate.

Rate Adders

All jurisdictions require surcharges to be added to the posted transmission rates in order to recover costs of the Ancillary Services (AS) and Market Administration Service (MAS) that are required for reliable power system and market operation. The assignment of AS and MAS to ETS transactions varies from jurisdiction to jurisdiction and there is the wide variation in the application of AS and MAS in each of the jurisdictions. Appendices I through V provide additional detail for each jurisdiction regarding the actual AS and MAS rate adders that are applicable for ETS related transactions.

Although there appears to be considerable variation in the assignment of AS and MAS to ETS transactions, it is quite possible that in some instances some of the AS are inclusive of other AS. For example Scheduling, System Control and Dispatch may include, as uplift, energy imbalance services. Also, some AS may be included in the posted transmission service rate as is the case in TransÉnergie where Scheduling, System Control, and Dispatch is included in the OATT, rather than being a stand-alone charge.

Discounting Provisions

The OATT contains provisions for discounting of transmission services that relies on the following principles:

1. Any offer of a discount made by the transmission provider must be announced to all eligible customers solely by posting on the OASIS;
2. Any customer-initiated requests for discounts (including requests for use by one's wholesale merchant or an affiliate's use) must occur solely by posting on the OASIS; and
3. Once a discount is negotiated, details must be immediately posted on the OASIS. For any discount agreed upon for service on a path, from point(s) of receipt to point(s) of delivery, the transmission provider must offer the same discounted transmission service rate for the same time period to all eligible customers on all unconstrained transmission paths that go to the same point(s) of delivery on the transmission system.

These principles have not changed since 2006 and there does not appear to be any public information available to ascertain the amount of discounting that takes place, nor the frequency of occurrence.

6. Concluding Remarks

Based on the review carried out in this study, there does not appear to be any evidence to suggest that the process for calculating transmission service charges has changed since 2006, when Rudden reported its review on the subject matter. The underlying principles appear to be the same and these are governed by Open Access Transmission Tariffs, which are approved by FERC in US and Régie de l'énergie in Québec, Canada.

Export Transmission Service continues to be provided under the Firm and Non-Firm Point-to-Point transmission service categories, the rates for which have not changed over the past five years in PJM. Rate changes were noted for the MISO, ISO-NE and TransÉnergie transmission tariffs. Furthermore, the rates applicable in NYISO are different from those described in the Rudden Report to reflect the application of weighting factors that adjust the rates to reflect the usage of different transmission facilities within the New York control area.

Furthermore, there does not appear to be any progress in eliminating transmission rate pancaking for inter-market transactions, apart from those that were noted in 2006, i.e., between NYISO and ISO-NE, and between PJM and MISO. Discussions are continuing between the various parties to ascertain what can be done to move forward to improve inter-market transaction efficiency. Thus ETS rates continue to apply for transactions between NYISO and IESO, between NYISO and PJM, between TransÉnergie and IESO, between TransÉnergie and NYISO, between TransÉnergie and ISO-NE, and between MISO and IESO.

The scope and variety of Ancillary Services and Market Administration Services and their application to ETS transactions varies considerably across the different jurisdictions. Even though transmission tariffs are no longer levied on ETS transactions between some jurisdictions, charges for Ancillary Services and Market Administrative Services continue to be levied on ETS transactions in all jurisdictions.

Appendix I – MISO Transmission Rates

Transmission Service Charges Design

In accordance with Schedule 7 of the MISO OATT[36], the ETS transmission service is a PTP service which is called the Drive-Out and Drive-Through ISO transmission service. This rate is calculated as an average annual rate that is developed from the gross sum of the transmission revenue requirement of all transmission owners in MISO less the sum of any applicable credits, the net value then being divided by a demand factor that accounts for all of the demands of the respective transmission owners as outlined on page 6 of Attachment O to the OATT. The ETS service is also offered on a Firm and Non-Firm basis for different time periods and this is achieved by dividing the annual rate by the appropriate period factors referred to in Section 5 of this report. The rate formula is provided in Attachment O of the OATT. This calculation is similar to that carried for the same type of service in other jurisdictions that use capacity based rates.

Rate Adders

Table I (a) below summarizes the Ancillary Services and Market Administration Services that are levied by the MISO on ETS transactions. These rates are expressed in 2011 $C, and will be added to the posted MISO transmission service rates listed in Table 5.1 in Section 5 of this report to determine the total charges applicable for ETS transactions.

[36] https://www.midwestiso.org/Library/Tariff/Pages/Tariff.aspx

TABLE I (a) – Ancillary and Market Administration Services			
Transmission[37] (Ancillary Service)		Peak $/MWh	Off-Peak $/MWh
	Scheduling, System Control, and Dispatch Service	0.1581	0.0791
	Reactive Supply and Voltage Control	0.4942	0.2372
	ISO Cost Recovery Adder	O.0988	0.0988
	Network Upgrade Charge for Transmission Expansion Plan	0.5634	0.2669
Market[38]	FTR-related	0.0099	0.0099
	Market administration	0.0890	0.0890
	Local Balancing Authority Cost Recovery	0.0099	0.0099
	Total	1.4233	0.7907

[37] These are 2011 values obtained from https://www.midwestiso.org/Library/Repository/Report/Rates/Zonal%20Pricing.pdf.
[38] These are 2012 values obtained from https://www.midwestiso.org/_layouts/MISO/ECM/Redirect.aspx?ID=96170.

Appendix II – PJM Transmission Rates

Transmission Service Charge Design

The process used to develop Network Integration and PTP transmission service charges is the same as previously described in the 2006 Rudden Report and contained in the PJM OATT[39]. Customers that purchase PTP transmission service are entitled to transfer power from a specified POR to a specified POD into, from, or through the PJM Control Area. Both Firm and Non-Firm PTP Service are available for specific needs and term periods. The maximum term of Firm PTP Service is determined based upon available transfer capability for future periods and is specified. In scheduling transactions, Firm PTP Service has priority over Non-Firm PTP Service. The charge for Firm PTP Service is based on the reserved capacity and not on actual usage.

For transactions within the PJM control area only one set of zonal transmission charges apply, typically in the zone where the load is located thus preventing pancaking of rates. For ETS transactions the applicable transmission charges are set based on a PJM Border Rate which is the weighted average of the zonal Network Service rates for all PJM zones. The current values for the Network Integration and PTP transmission rates in the PJM Control Area remain unchanged from those previous presented in the 2006 Rudden Report, as does the Border Rate that applies to ETS transactions.

Rate Adders

ETS transactions are eligible for additional charges that are levied by the ISO in the PJM Control Area. Table II (a) below summarizes the Ancillary Services and other related charges that are applicable to ETS transactions out of the PJM control area. All rates are $/MWh shown in 2011 $C. The total charges would be added to the posted PJM transmission service rates shown in table 5.1 to arrive at the total charges assigned to ETS transactions.

[39] http://www.pjm.com/~/media/documents/agreements/tariff.ashx.

TABLE II (a) Ancillary Services and Other Charges Applicable to ETS Transactions in PJM - $/MWh		
Scheduling, System Control and Dispatch Service	PJM Administrative Fees	0.3756
	NERC/RFC	0.0198
Ancillary Services	Voltage Control	0.3756
	Black Start	0.0198
	Operating Reserve	0.8896
	Regulation & Frequency Control	0.3558
	Synchronized Reserve	0.0890
Transmission Related	Transmission Owner (Schedule 1A)	0.0890
	Transmission Enhancement Cost Recovery	0.2768
	Total AS and Other Charges	2.4909

Appendix III – NYISO Transmission Rates

Transmission Service Charge Design

Transmission Service provided in NYISO includes Network Service, Firm PTP and Non-Firm PTP. Charges for all three types of service are based on actual transmission use with billing units measured in MWh. Pricing for Network Service and Firm PTP Service includes the components listed below.

Transmission $ = TSC + TUC + NTAC

TSC = Transmission Service Charge, to recover the embedded costs of the Transmission Owners; assessed based on the zone in which load is located. In the case of exports, it is based upon the zone at the point of exit.

TUC = Transmission Usage Charge, is a market-based charge that includes:

- Congestion charges
- Marginal loss charges

NTAC = NYPA (an agency of the state of NY) Transmission Adjustment Charge, to recover the portion of NYPA's Transmission Revenue Requirement that is not recovered through the transmission owners TSC.

Of these three components, the TSC and NTAC are the two which are the focus of this study. Of these, the TSC is considerably larger.

As per the NYISO OATT Schedule H[40], the wholesale TSC recovers each Transmission Owner's embedded costs, as well as the transmission component of their control area costs, and is determined separately for each load zone.. The TSC is adjusted to account for revenues from grandfathered agreements, financial transmission rights (TCCs), and congestion payments. The net of all these quantities for each Transmission Owner is divided by the total annual billing quantities (MWh) to give a $/MWh rate.

TSCs for ETS are specific to the locations of a transaction's source and sink. The purpose of this rate design, developed by the Transmission Owners during the formation of the NYISO, was to

[40] http://www.nyiso.com/public/webdocs/documents/tariffs/oatt/oatt_attachments/att_h.pdf.

allocate charges and revenues for exports and wheel-through transactions in a way that reflected the use of multiple Transmission Owners' facilities by a single transaction, as well as the divergence of revenue requirements for each Transmission Owner.

For either spot market exports or wheel-through transactions, if the receiving control area is not adjacent to the New York Control Area, the NYISO deems the sink to be the neighbouring area that is next in the transaction path, for purposes of determining the applicable charges. For spot market exports, the source is deemed to be the NYISO Reference Bus; for wheel-through transactions, the source is the proxy bus for the prior adjacent control area in the transaction path.

The TSC for an export transaction is calculated as a weighted average of the wholesale TSCs of the Transmission Owners whose facilities are deemed to be used by the transaction. For this purpose, loop flows through neighbouring control areas other than the sink control area are ignored. For example, an export to PJM is deemed to use only facilities making up the NYISO-PJM interface, even though some of the actual flow will go through Ontario. The weighting factor used to calculate the export TSC component for a particular Transmission Owner facility is the distribution factor for flows between the source and sink on that facility.[41] These distribution factors are determined and published in advance, in accordance with the NYISO Transmission Services Manual[42] which discusses the New York transmission system, the scope of transmission services provided and billing for the various transmission services. Effectively, paying the weighted average export TSC requires Transmission Customers to pay the sum, for each Transmission Owner, of the product of the applicable adjusted wholesale TSC and the associated flow in MWh as determined by the distribution factors.[43]

As per the Transmission Services Manual the four external zones are HQ (Zone M), ISO-NE ("NEPEX", Zone N), Ontario (Zone O) and PJM (Zone P). The analysis performed by the NYISO to determine ETS rates based on the distribution factors is summarized in spreadsheets that are made available to the public. These files include distribution factors on each transmission facility used by a

[41] For example, if half of the flow between the source and sink flows on a particular transmission line, the corresponding distribution factor would be 0.5.
[42] NYISO Transmission Services Manual; Rev 2.0; January 20, 2005.
[43] *Ibid*; Section 4.2.7

given source and sink location, the owner of that facility and TSC for that owner, and the charges applied against a transaction between the source and sink locations. Based on this information the following average wholesale TSC charges were applicable for ETS transaction in 2011:[44]

	$/MWh		
Transmission Charge	NYISO-ONTARIO	NYISO-PJM	NYISO-TransEnergie
TSC	3.3088	4.7470	2.1647
NTAC	0.7586	0.7586	0.7586
Total TSC	4.0674	5.5056	2.9233

The NTAC charge is based on NYPA's revenue requirement adjusted for revenues from other sources. No charges appear in relation to transactions between NYISO and ISONE as these entities have agreed not to assign transmission charges for export transactions.

TUC is the cost of congestion and losses (the differences between locational prices of energy between PORs and PODs).[45] The total transmission rate is the sum of the three components above. The calculations for the basic wholesale transmission service charges have not changed from those detailed in the 2006 Rudden Report.

ETS service includes Firm PTP Service and Non-Firm PTP Service, and is provided for term periods of varying duration. Charges are based on actual transmission use with billing units measured in MWh. Firm PTP Service is substantially the same as Network Service and has the same priority on the system. Non-Firm PTP Service is similar to Network Service and Firm PTP

44 http://mis.nyiso.com/public/P-62list.htm

45 In the case of a spot market export transaction, the TUC is zero, as energy is purchased at the external proxy bus Locational Based Market Price (LBMP), which includes congestion and losses implicitly.

Service, but does not include congestion charges in the TUC, and has a lower priority on the system. The service provision details remain the same as previously reported by Rudden.

Rate Adders

ETS transactions out of NYISO are subject to payment of Ancillary Services. Provided in Table III (a) below is a summary of the actual charges applied by the NYISO for transactions out of the control area to TransÉnergie, to Ontario and to PJM. The rates are expressed as $C/MWh. These are the average rates applied during 2011

TABLE III (a) – Ancillary Service Charges $/MWh			
	NYISO-TransÉnergie	**NYISO-ONTARIO**	**NYISO-PJM**
ISO Annual Budget Charges[46]	0.6919	0.6919	0.6919
Charges for Voltage Support Services[47]	0.3657	0.3657	0.3657
Operating Reserve Services[48]	0.3460	0.3460	0.3460
Regulation Services	0.1186	0.1186	0.1186
Uplift (market related services)[49]	0.4744	0.4744	0.4744
Total Ancillary Service Charge	1.9966	1.9966	1.9966

These rate adders would be added to the posted NYISO ETS transmission charges shown in Table 5.1 of Section 5 of this report to obtain the total charge applicable to ETS transactions.

[46] http://www.nyiso.com/public/market_data/pricing_data/rate_schedule_1.jsp.
[47] ibid.
[48] http://www.nyiso.com/public/documents/studies_reports/monthly_reports.jsp.
[49] Uplift costs include such things as Recovery of Day-Ahead Margin Assurance Payment Costs, Recovery of Import Curtailment Guarantee Payment Costs, Recovery of Bid Production Cost Guarantee Payment and Demand Reduction Incentive Payment Costs and others as per Schedule 1 of NYISO OATT.

Appendix IV – ISO-NE Transmission Rates

Transmission Service Charge Design

In New England, transmission open access provides the ability to make use of existing transmission facilities that are owned by others, in this case the Pool Transmission Owners (PTO) that make their Pool Transmission Facilities (PTF) available under the Transmission Operating Agreement (Agreement) and the OATT. The PTF are operated as part of a single New England Control Area (NECA).

As per Schedule 8 of the OATT[50], the ETS transactions are made under a Point-to-Point transmission service called the "Through or Out" service, and these are scheduled by the ISO-NE over the PTF. Each Transmission Customer that takes "Through or Out Service" is required to pay to the ISO-NE a charge per kilowatt of Reserved Capacity based on an annual rate which is the Pool PTF Rate. The Pool PTF Rate is determined annually and is equal to: (i) the sum for all PTOs of Annual Transmission Revenue Requirements plus the Forecasted Transmission Revenue Requirements and Annual True-ups determined in accordance with Attachment F of OATT, divided by; (ii) the sum of the coincident Monthly Peaks of all Local Networks. The rate per hour for "Through or Out Service" is the annual Pool PTF Rate divided by 8760. No other term rates are offered under the OATT.

All Through or Out Service offered under this OATT are deemed to have the same transmission priority. Through or Out Service have transmission priority equal to Native Load Customers, Network Customers and customers for Excepted Transactions. Therefore there is no distinction between Firm and Non-Firm transactions.

Through or Out Service by the Transmission Customer is set forth in the schedule submitted in accordance with the ISO System Rules. When a Real-Time External Transaction that exports energy out of or wheels energy through the New England Control Area is submitted by the Transmission Customer and is scheduled in the Real-Time Energy Market, the submission is deemed a request for Through or Out Service and the ISO will generate a reservation for

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[50] http://www.iso-ne.com/regulatory/tariff/sect_2/oatt/sect_ii.pdf.

Through or Out Service equal to the Real-Time External Transaction's maximum scheduled flow during the operating hour; this reservation amount is the basis for the Reserved Capacity.

Rate Adders

ETS transactions that do not have any load obligations in NECA are required to pay for two Ancillary Services as shown in Table IV (a) below. The costs are expressed in 2011 $C.

TABLE IV (a) – Ancillary Service Charges		
	$/kW-year	$/MWh
Scheduling, System Control and Dispatch Service[51]	1.5638	0.1785
Reactive Supply and Voltage Control Service[52]	1.7298	0.1977
Total AS Charges	3.2936	0.3762

These values would be added to the posted EST transmission charges in Table 5.1 of Section 5 of this report to arrive at the total charges applicable for EST transactions.

[51] http://www.iso-ne.com/trans/services/types_apps/rto_bus_prac_sec_2.doc .
[52] http://www.iso-ne.com/regulatory/tariff/sect_4/_sect_iva.pdf.

Appendix V – TransÉnergie Transmission Rates

Transmission Service Charge Design

In Québec the transmission service rates are derived on the same basis as in other jurisdictions that use capacity related rates, i.e. $/kW of reserved capacity. The annual rate is calculated using the transmission owner's annual transmission revenue requirement which is divided by the peak load during the year served from the transmission system. The other period rates are derived in a similar manner to that shown in Section 5 in this report and consistent with other jurisdictions that use capacity based rates.

The provision of transmission services is governed by the OATT[53] which is approved by Régie de l'énergie, the regulator in Québec. ETS transactions are provided under Firm and Non-Firm PTP transmission Services as described in Part II of OATT. Firm PTP Transmission Service always has a reservation priority over Non-Firm PTP Transmission Service under the provisions of the OATT, which is unique in this respect when compared to the other jurisdictions. ETS transactions are defined as Third-Party Sales that entail any sale in interstate, interprovincial or international commerce to a Power Purchaser that is not designated as supplying either Network Load under the Network Integration Transmission Service or the Distributor's Native Load.

Rata Adders

All ETS transactions are subject to the Ancillary Services which are listed in Table V (a) below. All rates are in 2011 $CAN.

[53] Hydro-Québec – OATT, May 5, 2011.

TABLE V (a) List of Ancillary Service Rates Applicable to ETS Transactions						
Ancillary Services	**Yearly per kW reserved**	**Monthly per kW reserved**	**Weekly per MW reserved**	**Daily Firm per MW reserved**	**Daily Non-Firm per MW reserved**	**Hourly per MW reserved**
System Control Service	Currently this is not a separate rate and is included in transmission charge					
Voltage Control Service	$0.32/kW	$0.03/kW	$6.15/MW	$1.23/MW	$0.88/MW	$0.04/MWh
Frequency Control Service	$0.33/kW	$0.03/kW	$6.35/MW	$1.27/MW	$0.90/MW	$0.04/MWh
Energy Imbalance Receipt - shortfall						¢0.011/MWh
Energy Imbalance Delivery - excess						¢0.011/MWh
OR – Spinning Reserve	$1.20/kW	$0.1/kW	$23.08/MW	$4.62/MW	$3.29/MW	$0.14/MWh
OR – Non –Spinning Reserve	$0.60/kW	$0.05/kW	$11.54/MW	$2.31/MW	$1.64/MW	$0.07/MWh
Total Ancillary Service charge	$2.45/kW	$0.21/kW	$47.12/MW	$9.43/MW	$6.71/MW	$0.29/MWh

The total Ancillary Service rate would then be added to each of the annual, monthly, weekly, daily and hourly transmission service rates thus giving the total charge for ETS transactions out of Québec.

Export Transmission Service (ETS) Tariff Study

SE-94

ieso Power to Ontario. On Demand.

Meeting Notes

Date: September 19, 2011	**Time:** 2:00 pm	**Location:** Conference call
Invited/Attended:	**Constituency Represented or Company Name:**	**Attendance Status:** (A)ttended; (R)egrets; (S)ubstitute
Ackerman, Dennis	Bruce Power	A
Butters, Dave	APPrO	A
Calic, Petar	Manitoba Hydro	A
Cary, Rob	Rob Cary & Associates (for Goreway)	A
Chintapalli, Raj	Customized Energy Solutions	A
Cormier, Pascal	Brookfield Renewable Power	A
Cowan, Allan	Hydro One Networks	A
Coyle, Emma	TransCanada	A
Dorey, Steve	Charles River Associates	A
Fraiture, Christian	RBC Capital Markets	A
Hamlyn, Alexander	Hydro One Networks	A
Harper, Bill	Econalysis Consulting Services	A
Keizer, Charles	Torys LLP	A
Kerr, Paul	Shell Energy	A
Kidane, Bayu	Elenchus on behalf of PWU	A
Maddix, Melanie	Goreway	A
McCuaig, Paul		A
Mehrabi, Neema	Bruce Power	A
Miles, Tony	Hydro One Networks	A
Pavo, Mike	Constellation Energy	A
Peterson, David	Ontario Power Generation	A
Plante, Matthieu	Hydro Quebec Energy Marketing	A
Shavel, Ira	Charles River Associates	A
Thiessen, Harold	Ontario Energy Board	A
Vennes, Yannick	Hydro Quebec Energy Marketing	A
Urukov, Vlad	Ontario Power Generation	A
Doyle, Declan	IESO	A
Ng, Hok	IESO	A
Rivard, Brian	IESO	A
Savage, Jessica	IESO	A

All meeting material is available on the IESO web site at:
http://www.ieso.ca/imoweb/consult/consult_se94.asp

Field

Item 1 – Introduction and Review of Agenda

Declan Doyle (IESO) welcomed the group and summarized the meeting agenda. He noted that the purpose of this meeting is to come to a decision on the proposed rate structures for inclusion in the ETS Tariff Study Request for Proposals (RFP). The IESO is also seeking input on specific rates to be studied.

Item 2 – Recap from Previous Stakeholder Session

Jessica Savage (IESO) summarized the key messages from stakeholders at the previous ETS session and described how that input was considered in framing the scope of the ETS tariff study. The IESO received seven written submissions. In response to that feedback, Jessica confirmed that the ETS Tariff Study will include a comparative assessment of the ETS tariff with respect to the following rate-making principles: simplicity; consistency with rates in other jurisdictions; fairness in apportioning costs of service among different consumers (i.e. cost causality); and efficiency. David Peterson (OPG) suggested that the accepted rate-making principles should be driving which rates to study rather than the other way around. Jessica responded that the purpose of the study is to perform an objective, analytical study on a range of tariffs, the results of which will serve as an input to the more subjective exercise of evaluating each option in terms of how they support specific rate making principles.

In response to other questions of clarification, Jessica confirmed that the efficiency assessment will consider the incremental changes in Global Adjustment and that the change in revenues associated with IESO wholesale market service charges under each ETS tariff will also be quantified.

Item 3 – Proposed ETS Tariffs: Structures and Rates

Jessica noted that the study will include two types of ETS tariffs: flat rate tariffs and two-tiered tariffs (on peak/off-peak). It was agreed that the options to be studied are:

- Three distinct flat rate tariffs: $0/MWh, $2/MWh, equivalent average network charge.
- Two distinct scenarios under the two-tiered tariff: $0/MWh off-peak and equivalent average network charge on-peak; $1/MWh off-peak and $3.50 on-peak.

Bill Harper (Econalysis Consulting Services) inquired if modeling only two scenarios under the on-peak/off-peak option provides will be sufficient for extrapolating a full range of likely results. Brian Rivard (IESO) responded that other rates under the on-peak/off-peak tariff design may be considered recognizing the need to contain costs.

Rob Cary (Rob Cary & Associates) inquired about the assumptions regarding OPA contracts that will be used in the study. For example, he cited that the Floor Price Focus Group discussions under SE-91: Renewable Integration could result in market rule amendments that may trigger contract changes. He also expressed concern that the Floor Price discussions need to happen sooner than later so that the assumptions underlying the ETS Tariff Study are valid. A discussion paper on Dispatch Order for Baseload Generation has since been published by the IESO in November. The discussions on dispatch order are on-going. As such, the study of tariff options will be conducted under two scenarios:

- Wind/solar can be dispatchable under SBG in advance of nuclear, and
- Wind/solar is non-dispatchable under SBG.

Yannick Vennes (Hydro Quebec Energy Marketing) suggested that the ETS Tariff Study should also consider costs that are not under contract, i.e. private costs. Brian Rivard responded that the study needs to be tractable and that private costs can only be considered to the extent they are reflected in bids and offers. Brian noted that net Ontario benefit will be measured as the sum of consumer surplus and producer surplus accounting for transmission revenue earned whereas regional efficiency is a measure of the generation cost required to satisfy demand in the region.

Rob Cary inquired how import and export revenues factor into Ontario producer and consumer surplus. [The calculation of producer and consumer surplus will be discussed in presentation on the Approach to the ETS Tariff Study on January 19th 2012.]

Paul McCuaig and Paul Kerr (Shell Energy) emphasized the importance of considering the extent to which transmission services provided to export customers differs from those provided to domestic customer, and if so, the extent to which each rate option reflects the relative cost differences incurred to provide these services. Brian Rivard responded that study will include an assessment of the extent to which each rate option is consistent with the principle of cost causality.

Paul McCuaig also inquired how the study would reconcile regional versus Ontario efficiency as those two concepts may be diametrically opposed. Brian Rivard responded that it can be done from a modeling standpoint. However, if there is tension between the two measures, the relative importance of these competing measures in determining the preferred ETS tariff is a decision for the Ontario Energy Board.

Rob Cary inquired whether baseload generation (SBG) assumptions will be based on historical patterns or forward-looking projections to which Brian Rivard responded that the SBG forecast assumptions will largely be determined by the IESO in consultation with the Ontario Power Authority (OPA) so that the assumptions are consistent with the OPA's Integrated Power System Plan. David Peterson (OPG) expressed concern about transparency of the inputs and Brian advised that there will be an opportunity for stakeholder comment on the inputs.

In the interest of producing a robust study that will not have to be repeated in the near future, Rob Cary suggested that the study should consider impacts over the next five years to ten years. Any study results beyond that time frame may not be reliable given that the underlying assumptions are less certain. Brian Rivard proposed that the study should model impacts up to six years out.

Rob Cary also asked if the study will consider the impact of various ETS tariffs on greenhouse gases/cost of carbon, and the role of the Western Climate Initiative. Brian Rivard committed to review if and/or how environmental policy was considered in the previous study.

Yannick Vennes inquired if the input data will be made available to market participants. Brian Rivard responded that seems unlikely due to confidentiality considerations.

Item 4 – Path Forward and Adjournment

The RFP for the ETS Tariff Study was posted in October 2012. Charles River Associates (CRA) was the successful bidder in a public request of proposal process to complete the ETS study.

Ontario Energy Board (Board Staff) INTERROGATORY #86 List 1

Issue 23 What is the appropriate level for Export Transmission Rates in Ontario?

Interrogatory

Ref: Exhibit H1-5-2/Appendix B/pp 22&23
In the bullet list on the bottom of page 22 and first paragraph on 23, a list of high-level calibration metrics are noted and it is stated:

"In our judgement, the calibration was reasonably close to actuals. In particular, generation by type, wholesale prices, and the relative pattern of export closely aligned with actuals. This gave us comfort in the starting point for the ETS study."

Given those calibration metrics, has CRA calculated the confidence level of the study conclusions? Alternatively, is there a confidence interval around the main conclusions, eg. the change in total surplus?

Response

CRA conducted a deterministic modeling rather than a statistical analysis. As such, no confidence intervals were calculated. A statistical analysis would first require development of probability distributions for key inputs and estimation of correlations among the inputs, followed by a Monte Carlo simulation in which key inputs are sampled and outputs calculated. Calculation of confidence intervals around key outputs using this methodology would require a large number of iterations for the *status quo* and for each ETS scenario. Given the amount of time required to prepare, run, and process a single iteration, the cost of calculating confidence intervals would vastly exceed the costs of the current study.

CRA modeled each ETS scenario plus the *status quo* for three separate years - with each year having different assumed generating unit capacities (for renewable, nuclear, and natural gas-fired generation); different energy demands in Ontario; different energy prices and generation capacities in neighboring markets; differing natural gas prices, etc., under two sets of assumptions about the implementation of the Western Climate Initiative, and two sets of dispatch scenarios under SBG events (nuclear first and wind first). Thus the CRA model results that have been reported already reflect a broad range of possible market conditions. In addition, in order to ensure the reliability of its results, CRA conducted internal (unreported) sensitivity analyses, including running the model under two sets of assumptions about the appropriate proxy for the HOEP and also under various plausible assumptions about the effective capacity at interties during SBG events. Furthermore, based on its extensive experience in applying the NEEM model, CRA also considered (internally) the effects of varying other key model assumptions on the *change* in outcomes between the *status qu*o and each ETS scenario, and concluded that it was comfortable with the reasonableness of the deltas predicted by the model. CRA notes that varying certain assumptions can have material effects on outcome *levels* without having a material effect on changes between the status quo and the modeled scenarios, which were the focus of CRA's analysis.

Ontario Energy Board (Board Staff) INTERROGATORY #87 List 1

Issue 23 What is the appropriate level for Export Transmission Rates in Ontario?

Interrogatory

Ref: Exhibit H1-5-2/Appendix B/p 30

In the section labelled **Intertie Congestion Revenue** related to the scenario Unilateral Tariff Elimination, the study defines this revenue as the difference between the price the IESO sells power for on congested transmission lines and the price it pays Ontario producers.

a) How does the IESO determine each of these prices?

b) Is the price determined on an hourly basis, or on some longer-term basis?

c) Please confirm that the congestion revenue is in addition to the "Uplift" that is charged by the IESO.

Response

a) When considering the response to this interrogatory and other interrogatories related to intertie congestion revenue, it should be noted that there is a difference between the Intertie Congestion ***Revenue*** as reported by CRA in the ETS study, and the Intertie Congestion ***Rent*** as calculated by the IESO as per the Market Rules.

In the CRA model, electricity is exported from a low price jurisdiction (i.e., Ontario) to a higher priced jurisdiction (the export market) until the prices in the two jurisdictions (net of any transactions costs) are equilibrated or until the transfer limit of the intertie connecting the two jurisdictions is reached. When the transfer limit of the intertie is reached, there is congestion and Intertie Congestion ***Revenue*** is calculated. The Intertie Congestion ***Revenue*** is calculated as the price in the export market less the price in Ontario and associated transactions costs (friction costs, the ETS tariff, and the uplift), multiplied by the volume of energy flowing over the export intertie. More specifically, the components of this calculation are as follows:

- The price in the export market is determined in the model as the cost of satisfying one additional MW of demand in the export market;
- The Ontario market price is determined in the model as the cost of satisfying one additional MW of demand in Ontario (a proxy to HOEP);
- The friction costs, as estimated by CRA, are meant to reflect market participant behaviour and the lack of full integration across markets that results in transactions that appear to be economic not occurring;

- The ETS tariff is set at the rate for the scenario being considered;
- The uplift is assumed to be a uniform (across all scenarios and all model years) $3.33/MWh, which is consistent with historical averages.

The IESO operates 14 pricing zones in the Ontario wholesale market; an Ontario zone and 13 intertie zones, one each for Manitoba, Michigan, Minnesota and New York, and 9 for Quebec. The IESO schedules exports in an intertie zone in the hour-ahead unconstrained pre-dispatch schedule whenever the bid price of the export exceeds the hour-ahead Ontario zone pre-dispatch price. When the amount of exports that bid into an intertie zone above the Ontario zone pre-dispatch price exceeds the transfer limits of the intertie, the intertie zone is congested and an Intertie Congestion Price (ICP) is calculated as per the IESO Market Rules, Chapter 7, Section 8.1.1A. The ICP is the difference between the intertie zone price which is equal to the bid value of satisfying one additional MW of demand in the intertie zone, and the Ontario zone pre-dispatch price. When an ICP is calculated, the IESO recovers an Intertie Congestion ***Rent*** which is equal to the ICP multiplied by that volume of exports scheduled in the intertie zone.

b) The ICP is calculated on an hourly basis in the one hour ahead pre-dispatch. The real-time energy market price in Ontario is determined as the cost of satisfying one additional MW of demand in Ontario and is computed on a 5-minute basis. The intertie zone price in real-time is determined by adding the ICP to the 5-minute energy market price in Ontario as defined in the IESO Market Rules, Chapter 9, Section 3.1.3[1]. Exports scheduled in an intertie zone pay the real-time intertie zone price.

c) As described in a) the Intertie Congestion ***Rent*** as calculated by the IESO is not charged as an uplift amount to consumers. For further clarification, Intertie Congestion ***Rents*** are not related to Congestion Management Settlement Credits (CMSC) which are paid (and charged as uplift) in respect of congestion on the internal IESO-controlled grid.

[1] ICP+MCP for the calculation of the real-time 5-minute intertie price is capped at +/-MMCP.

Ontario Energy Board (Board Staff) INTERROGATORY #88 List 1

Issue 23 What is the appropriate level for Export Transmission Rates in Ontario?

Interrogatory

Ref: Exhibit H1-5-2/Appendix B/p 33
In the section labelled **Intertie Congestion** Revenue related to the Equivalent Average Network Charge scenario, the study states:

"Whenever an intertie connected to Ontario is export congested, the price at that intertie zone is higher than the Ontario price. Exporters end up paying the IESO a higher price to take away power than what the IESO pays Ontario generators to supply the power. This price difference between the intertie zone and Ontario times the export quantity flowing over the constrained intertie is the congestion rent accrued to the IESO."

a) Does the IESO keep the revenue generated by the Intertie Congestion Revenue? If so, does it lower the amount that Ontario customers pay to the IESO to fund activities?

b) Did the study consider internal Ontario congestion and the payment of congestion management settlement credits caused by export flows or wheel-through transactions between the Ontario zones identified or within the zones?

Response

a) The Intertie Congestion ***Rent*** (not to be confused with Intertie Congestion ***Revenue***) described in the response to Interrogatory Response filed at Exhibit I, Tab 23, Schedule 1.04 Staff 87, is not kept by the IESO. It is for the most part, paid out to transmission rights holders, and any residual surplus accumulated above a certain pre-determined threshold set by the IESO Board is disbursed to Ontario consumers and exporters on a MWh basis.

b) CRA modeled the internal constraints for three Ontario sub-regions. Analysis of the constrained three-region model results indicated that internal congestion in the unilateral elimination tariff scenario would not lead to significant marginal cost differences in an unconstrained vs. constrained dispatch model run. This was also true for the Equivalent Average Network Charge (EANC) scenario. The EANC and unilateral elimination are the extreme cases. Therefore, it follows that the CMSC payments in all model runs would be relatively small. Consequently, the changes in CMSC payments between ETS scenarios would be negligible.

<u>Ontario Energy Board (Board Staff) INTERROGATORY #89 List 1</u>

Issue 23 What is the appropriate level for Export Transmission Rates in Ontario?

Interrogatory

Ref: Exhibit H1-5-2/Appendix B/p 52
In the first bullet of the section of the table labelled Consistency, it is stated:

"Consistent with ETS rates between NYISO and ISONE and between MISO and PJM (Note that these are bilateral deals, not unilateral actions)."

a) What would be the benefits if the Board were to direct the IESO to negotiate bilateral deals with interconnected jurisdictions that vary from an established ETS down to a level of $0/MWh?

b) Could the IESO accomplish this at the same time as it determines the amount of *Intertie Congestion* Revenue?

Response

a) As indicated in response to Interrogatory Response filed at Exhibit I, Tab 23, Schedule 1.02 Staff 85, specific bilateral deals (ranging from an established ETS down to $0/MWh) with interconnected jurisdictions were not selected by stakeholders as tariff options to be studied. As such, it is not known what the benefits of specific bilateral deals would be.

b) Discussion of intertie congestion revenue is covered in the answer to Interrogatory Response filed at Exhibit I, Tab 23, Schedule 1.04 Staff 87.

Ontario Energy Board (Board Staff) INTERROGATORY #90 List 1

Issue 23 **What is the appropriate level for Export Transmission Rates in Ontario?**

Interrogatory

Ref: Exhibit H1-5-2/Appendix B/pp 41, 46 & 92
In Table 13 of the main study and in the Addendum (assuming the Ontario joins the Western Climate Initiative before 2015 and does not join it before 2018, respectively), the option "Two-tiered Scenario B" shows consistently positive Total Ontario Surplus and Class B Consumer Surplus relative to the status quo scenario. Further, this option has only a small effect on ETS revenue and the summary at p. 46 appears to contain no serious drawbacks.

Why does Hydro One not recommend this option, rather than continuing with the status quo (single tier @ $2/MWh)?

Response

The Export Transmission Service (ETS) Tariff Study does not make a recommendation as to the preferred option. Hydro One believes it would be premature to put forward a recommendation until the study has been fully examined in this proceeding.

Hydro One will update the ETS revenue amounts as part of its Draft Rate Order to reflect the Board's Decision with Reasons once it is released and the continuation of the approved variance account will track volume variances.

Ontario Energy Board (Board Staff) INTERROGATORY #91 List 1

Issue 23 What is the appropriate level for Export Transmission Rates in Ontario?

Interrogatory

Ref: Exhibit H1-5-2/Appendix B/pp 51 & 56
Please confirm that there is no intertie between the Ontario Northeast Sub-Region and Michigan. Please confirm that the transfer limits between Michigan and the "Rest of Ontario" are expected to decline in future relative to the current capacity, and describe what is causing the decline.

Has Hydro One or IESO filed for the record of this proceeding the Responses to Stakeholder Comments and Questions that were distributed on June 22, 2012?

If or when this document is available, there are two questions relating to item # 8 (p 6):

a) Please describe what is meant by "friction cost", and how is it determined?

b) Is the assumption that CRA has used concerning allocation of Intertie Congestion Revenue reasonably accurate – i.e that the revenue accrues to Ontario when the intertie is congested by exports and none accrues to Ontario when the intertie is congested by imports?

Response

The Ontario Northeast Sub-Region and Michigan are not connected by an intertie. Limits for flows into Ontario through the Michigan intertie are based on those described in the Ontario Transmission System report published by the IESO: http://www.ieso.ca/imoweb/pubs/marketReports/OntTxSystem_2011nov.pdf

The Responses to Stakeholder Comments and Questions distributed on June 22, 2012 were not filed for this proceeding. The responses have been published on IESO's website: http://www.ieso.ca/imoweb/pubs/consult/se94/se94-20120622-Responses_to_Stakeholder_Questions.pdf

a) Friction Costs are meant to reflect market participant behaviour and lack of full integration across markets that results in transactions that appear to be economic not occurring. These are generally higher for interfaces that involve RTOs and non-RTO regions than between RTOs. In addition to open markets, RTOs often make an attempt to coordinate dispatch and operations across seams, which reduces the Friction Costs. Nevertheless, there are always imperfections in market operations across seams which CRA models as Friction Costs. As discussed with stakeholders during the assumptions conference call (January 2012), the frictions are CRA estimates.

b) Prices on congested interties, which determine the allocation of the Intertie Congestion ***Revenue***, will typically fall between prices in the exporting and importing markets. There is no practical way of forecasting the precise allocation of this Intertie Congestion ***Revenue*** between the exporting and importing markets. A reasonable model of competition at interties and historical data on transaction prices at interties and/or margins for exporters and importers would be required to test and calibrate the model. The information required to estimate the historical allocation of Intertie Congestion *Revenue* is not publically available. The assumption that all the intertie congestion revenue accrues to the exporting jurisdiction and none to the importing market may slightly overstate the net benefit to Ontario when Ontario is a net exporter (2013 and 2015) and understate the net benefit when Ontario is a net importer (2017).

Ontario Energy Board (Board Staff) INTERROGATORY #92 List 1

Issue 23 What is the appropriate level for Export Transmission Rates in Ontario?

Interrogatory

Ref: Exhibit H1-5-1/p 4 Next Steps
Does the IESO and/or Hydro One have a recommendation for when the CRA study should be repeated so that ETS tariffs could potentially be revised?

Response

The participating stakeholders in IESO Stakeholder Engagement 94 agreed that it was appropriate for the purposes of the study to model 2013, 2015, and 2017. It may therefore be appropriate to repeat the study sufficiently in advance of 2017; or before then if there is a material change in the assumptions which underlie the study.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #41 List 1

Issue 23 What is the appropriate level for Export Transmission Rates in Ontario?

Interrogatory

Reference: Exhibit H1, Tab 5, Schedule 2, Appendix B, page 7

(Note- Appendix B page references are with respect to the page numbering as shown at the top of each page out of 1 02)

a) The third bullet under Quantitative Results states that "the net impact on consumers' bills .... is generally small". Please clarify what is meant by "consumers' bills" - is it the total bill or the energy portion of consumers' bills?

Response

a) The statement “the net impact on consumers’ bills…is generally small” refers to the total change in electricity bills Ontario consumers face, which is measured by the change in consumer surplus.

Vulnerable Energy Consumers Coalition (VECC)INTERROGATORY #42 List 1

Issue 23 **What is the appropriate level for Export Transmission Rates in Ontario?**

Interrogatory

Reference: Exhibit H1, Tab 5, Schedule 2, Appendix B, pages 5, 10 and 48-50

a) What are the assessment criteria that Hydro One uses in establishing the cost allocation policies for transmission and designing the uniform transmission rates?

b) In Hydro One's view, to what extent are the criteria used in the IESO report for assessing ETS rate options consistent with the criteria Hydro One uses for cost allocation and rate setting for uniform transmission rates.

c) With respect to the first paragraph on page 1, is there a difference between "net economic benefits to groups in Ontario" and the evaluation done based on "efficiency"?

Response

a) The assessment criteria used in proceeding RP-1999-0044, which largely established the design of Transmission rates, took into account cost causality, efficiency and fairness (Decision with Reasons, pg.43) as well as administrative simplicity and cost (Decision with Reasons, pg.36). Hydro One’s Transmission application EB-2005-0501, Exhibit G1, Tab 1, Schedule 1, pg.5-6 also identified a number of ratemaking criteria used in establishing transmission rates.

b) The criteria used in the IESO report include the criteria referenced by the OEB in their Decision in RP-1999-0044 and are among the criteria referenced in Hydro One’s EB-2005-0501 application.

c) No. Net economic benefit to groups in Ontario is measured by the change in total surplus, which is the standard measure of the effects of a policy on economic efficiency.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #43 List 1

Issue 23 What is the appropriate level for Export Transmission Rates in Ontario?

Interrogatory

Reference: Exhibit H1, Tab 5, Schedule 2, Appendix B, pages 8 and 13-14

a) Please provide a schedule that sets out the overall Ontario supply/demand situation for each of three years modelled and indicate the extent to which there is surplus capacity in each. As part of the schedule, please show the amount of "contracted supply" in each of the three years.

Response

a) The table below shows the overall supply/demand balance for each model year. Total Ontario contracted supply and peak demand for each year are also reported.

	2013	2015	2017
Nuclear	12,946	12,946	9,540
Coal	2,291	0	0
Natural Gas	7,651	7,626	7,733
Biomass	422	508	512
Other	2,826	3,071	3,071
Total Dispatchable	**26,136**	**24,151**	**20,856**
Hydro	8,312	8,872	8,874
Wind (Nameplate)	2,681	6,054	6,964
Solar	1,467	2,302	2,868
Total Energy Limited	**12,460**	**17,228**	**18,706**
TOTAL Supply	**38,596**	**41,379**	**39,562**
Non-Contracted Supply	***3,684***	***3,684***	***3,684***
Total Contracted Supply	***34,912***	***37,695***	***35,878***
Peak Demand	**25,571**	**25,819**	**25,764**

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #44 List 1

Issue 23 What is the appropriate level for Export Transmission Rates in Ontario?

Interrogatory

Reference: Exhibit H1, Tab 5, Schedule 2, Appendix B, pages 48-49

a) The text describes a range of views regarding fairness. Is there any jurisdiction that bases its transmission rates on an equal sharing of cost recovery between all users of the transmission infrastructure, irrespective of how often that infrastructure is used? If so, please outline the jurisdiction and tariff used.

b) Why should users whose transactions "go through" 93%- 95% of the time be viewed as "infrequent users" as the text on page 49 appears to suggest?

Response

a) As part of the SE 94 process, CRA produced and posted an "Export Transmission Service Study Review of Rates in Neighbouring Markets" (Please see Attachment 1 in response to Exhibit I, Tab 23, Schedule 1.02 Staff 85). That study provides details on the various approaches to ETS rate setting in five neighbouring markets.

b) The term "infrequent user" refers to the frequency with which the transmission system is used, not the frequency with which transactions fail or go through.

Vulnerable Energy Consumers Coalition (VECC)INTERROGATORY #45 List 1

Issues 23 What is the appropriate level for Export Transmission Rates in Ontario?

Interrogatory

Reference: Exhibit H1, Tab 5, Schedule 2, Appendix B, pages 9, 10 and 48-49

a) Please provide a copy of the document "Review of Rates in Neighbouring Markets" for the current proceeding's record.

b) For each of the five jurisdictions surveyed, is the derivation of the both the Network Service Rate (typically used for domestic network customers) and the PTP Rates used for exports based on the FERC approved OATT requirements as described at page 15 of the Review ? If not, what is the overall basis for the rate derivation?

c) Please confirm that under the FERC approved OATT requirements, the rates for PTP service are generally derived by translating the annual Network Service rate into equivalent rates for shorter periods of time? If not, please indicate where a different approach is used.

d) Please comment on the extent to which the export tariffs in each of the surveyed jurisdiction are based on i) a sharing of the costs of transmission infrastructure with other users based on frequency of usage, vs. ii) a marginal cost of usage approach as discussed on page 49.

Response

a) Please refer to Interrogatory Response filed at Exhibit I, Tab 23, Schedule 1.02 Staff 85, Attachment 1.

b) Yes, for most of the jurisdictions surveyed, both the Network Service Rate and the PTP rate are based on FERC approved OATT requirements. In the case of Quebec, the OATT is approved by the Régie de l'energie.

c) Confirmed.

d) None of the export tariff rate structures surveyed are based on a marginal cost of usage approach.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #46 List 1

Issue 23 What is the appropriate level for Export Transmission Rates in Ontario?

Interrogatory

Reference: Exhibit H1, Tab 5, Schedule 2, Appendix B, pages 9 and 48-49

Preamble: The main report state that 7% of on-peak and 5% of off-peak export transactions fail and more than half are due to operator actions.

a) Please provide a schedule that sets out the total number of successful and failed export transactions for each of the most recent 24 months where data is available.

b) When export transactions fail, are the "potential" exporters provided any compensation? If so, please outline under what circumstances compensation is provided and how it is determined. Also, please revise the schedule provided in response to part (a) to indicate the number of failed transactions in each month where compensation was provided and the total amount of compensation provided in each month.

Response

a) The table below shows the number of successful export transactions and export transactions coded as failed in the most recent 24 months. The coding of failed transactions is described in Table 1-1 of IESO Market Manual 4.3, Section 1.7.

Year	Month	Number of Successful Export Transactions	Number of Failed Export Transactions	Total Number of Export Transactions
2010	September	13784	599	14383
	October	10453	425	10878
	November	10782	435	11217
	December	20604	954	21558
2011	January	16281	3203	19484
	February	12500	1239	13739
	March	11698	1406	13104
	April	12973	922	13895
	May	19295	1219	20514
	June	12678	830	13508
	July	15941	918	16859
	August	14100	870	14970
	September	10053	594	10647
	October	11936	488	12424
	November	11324	287	11611
	December	11850	700	12550
2012	January	16503	581	17084
	February	14613	1327	15940
	March	16256	1397	17653
	April	17309	1349	18658
	May	15161	982	16143
	June	16235	673	16908
	July	18743	485	19228
	August	17525	476	18001

b) When export transactions fail, the exporter is compensated according to IESO Market Manual 4.3, Section 1.7, principle 6, which states: "The *market participant* whose transaction is affected by the *IESO* manual intervention shall be eligible for the same market compensation and be subject to the same risks as if the transaction was scheduled in the hour ahead *pre-dispatch schedule*."

The table below shows the number of failed export transactions compensated based this principle.

Year	Month	Total Number of Failed Transactions	Total Number of Failed Transactions Due to IESO Manual Intervention and Compensated	Total Amount of Compensation
2010	September	599	77	$62.6k
	October	425	41	$13.1k
	November	435	64	$14.3k
	December	954	87	$38.2k
2011	January	3203	41	$5.5k
	February	1239	130	$28.2k
	March	1406	131	$82.5k
	April	922	325	$168.7k
	May	1219	125	$214.2k
	June	830	43	$82.6k
	July	918	82	$45.8k
	August	870	47	$15.0k
	September	594	33	$22.8k
	October	488	12	$2.3k
	November	287	16	$4.1k
	December	700	29	$2.2k
2012	January	581	20	$5.1k
	February	1327	38	$72.4k
	March	1397	127	$77.9k
	April	1349	22	$6.1k
	May	982	103	$84.8k
	June	673	153	$78.4k
	July	485	63	$32.9k
	August	476	63	$44.1k

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #47 List 1

Issue 23 **What is the appropriate level for Export Transmission Rates in Ontario?**

Interrogatory

Reference: Exhibit H1, Tab 5, Schedule 2, Appendix B, pages 9 and 49-50

a) In order to help put the changes in Consumer and Ontario surplus in to context, please provide the total Consumer and Total Ontario surplus under the Status Quo scenario for each of the three years modelled.

Response

a) CRA did not calculate the levels of consumer surplus or total surplus.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #48 List 1

Issue 23 What is the appropriate level for Export Transmission Rates in Ontario?

Interrogatory

Reference: Exhibit H1, Tab 5, Schedule 2, Appendix B, pages 10 and 22-23

Preamble: The calibration assessment appears to indicate that one of the areas where the model is most inaccurate is in terms of modeling export volumes.

a) The Report (page 14) looks at generation type, wholesale prices and pattern of exports when concluding that "the calibration was reasonably close to actuals". However, given that the focus of the study is export tariffs, their impact to export volumes and the ensuing impact on market prices, etc.; why shouldn't the ability of model to predict export volumes be the prime consideration when assessing the accuracy of the model?

b) Given the variation in actual vs. modeled export volumes, what degree of certainty (or alternatively range of uncertainty) should be associated with the level of export volumes modelled for 2013, 2015 and 2017?

Response

a) As explained in the report, the model was well calibrated on multiple dimensions. While the overall export levels were low in the model, the distribution of exports was quite realistic. CRA expects that the changes in the model due to changes in the ETS tariff (i.e., policy impacts) are realistic.

b) Please see above response.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #49 List 1

Issue 23 What is the appropriate level for Export Transmission Rates in Ontario?

Interrogatory

Reference: Exhibit H1, Tab 5, Schedule 2, Appendix B, page 14

a) The analysis undertaken by CRA assumed that the Ontario load is inelastic (i.e., does not change in response to a change in price). If one was to take into account that price does affect demand, please comment (directionally) on the impact this would have on the results set out in Table 12 and Table 13. In doing so, please assume that price has a greater impact on the demand levels for Class A load (i.e., typically industrial customers).

Response

a) While changes in ETS rates and structure have a meaningful impact on market price, the impact on demand and on the total energy price Ontario consumers see would differ due to the role of the Global Adjustment and the impacts on the welfare of different consumer classes could move in opposite directions, making the direction of the aggregate impact on Consumer Welfare (as shown in Table 12) uncertain. CRA has not carried out the analysis requested, but one would expect to see:

- Increased demand by Class A customers when HOEP falls (EANC) and lower demand when it increases (Unilateral Elimination).
- Modest reduction in demand by Class B customers when HOEP falls, since GA increase more than offsets the market price reduction in EANC case. Slightly higher demand by this Class when HOEP increases in the Unilateral Elimination case.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #50 List 1

Issue 23 What is the appropriate level for Export Transmission Rates in Ontario?

Interrogatory

Reference: Exhibit H1, Tab 2, Schedule 2, Appendix B, pages 17 and 101

a) Assuming Ontario is not part of the WCI for 2015 and 2017, please indicate those jurisdictions to which it exports and that are assumed to be participating in the WCI and therefore would apply a charge for carbon intensity to imports from Ontario in each of those years.

b) Assuming Ontario is part of the WCI for 2015 and 2017, please indicate those jurisdictions from which it imports and that are assumed not to be participating in the WCI and therefore Ontario would apply a charge for carbon intensity in each of those years.

c) To whom would the revenues that Ontario would make (as a participant in the WCI) through carbon intensity charges on imports from jurisdictions that are not part of WCI accrue?

d) How are revenues that Ontario would make (as a participant in the WCI) through carbon intensity charges on imports from jurisdictions that are not part of WCI treated in the analysis?

e) Please provide a schedule similar to Table 3 (page 29) that sets out the change in imports for each of the alternatives considered and also details (assuming Ontario is part of WCI) the change in the volumes that would be subject to a charge for carbon intensity and the associated revenues.

Response

a) If Ontario is not part of the WCI in 2015 and 2017, a carbon import charge would apply to Ontario exports into Quebec, and possibly Manitoba, if it implemented carbon pricing. The charge applied to exports from Ontario to Quebec would be substantially smaller than the charge on imports into Quebec from other neighbouring markets, due to the lower carbon intensity of the Ontario power sector, once coal is eliminated from the Ontario fuel mix.

b) The jurisdictions that Ontario would apply a charge to would be NY, PJM, NE and MISO.

c) Since Ontario has not designed a carbon pricing regime, it is premature to speculate on how any proceeds might be employed.

d) Carbon import charge revenue would contribute to consumer surplus. However, virtually all of the import changes resulting from changes in ETS rates in the non-WCI case were from Quebec and Manitoba. Since Quebec is a participant in the WCI carbon pricing regime and the carbon intensity in Manitoba's power sector is extremely low, this revenue source contributes virtually nothing to consumer welfare changes.

e) The following table shows the change in total imports to Ontario relative to the status quo by scenario and model year, for each region. The only neighbouring regions from which there is a change in Ontario imports are Quebec and Manitoba. There is no carbon charge on imports from Quebec, which is part of the WCI. The carbon content of imports from Manitoba is minimal and the annual change in carbon charges is less than $10,000 in any year.

Change in Ontario Imports (Scenario - Status Quo), Total and by Region

	Unilateral Elimination Scenario			Equivalent Average Network Charge Scenario			Two-Tier Scenario A			Two-Tier Scenario B		
	2013	2015	2017	2013	2015	2017	2013	2015	2017	2013	2015	2017
New York	0	0	0	0	0	0	0	0	0	0	0	0
Michigan	0	0	0	0	0	0	0	0	0	0	0	0
Manitoba	0	49,750	51,278	0	1	-162,731	0	0	-42,370	0	0	14,744
Minnesota	0	0	0	0	0	0	0	0	0	0	0	0
Quebec	3	610,373	128,323	3	-272,300	-411,736	4	-179,685	-227,519	3	-106,980	-139,151
Total Imports (MWh)	**3**	**660,123**	**179,601**	**3**	**-272,299**	**-574,467**	**4**	**-179,685**	**-269,889**	**3**	**-106,980**	**-124,407**

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #51 List 1

Issue 23 What is the appropriate level for Export Transmission Rates in Ontario?

Interrogatory

Reference: Exhibit H1, Tab 5, Schedule 2, Appendix B, page 32

a) The analysis assumes that the uplift rate stays constant ($3.33/MWh) and that a change in export volumes leads to a corresponding change in uplift revenues to the benefit of Ontario consumers. Is this how it works in reality?

b) If there are no additional costs associated with an export volume increase, why wouldn't the uplift charge go down - such that previously existing exports also benefit? Alternatively, if there are additional costs such that the uplift rates stays the same why wouldn't some (all) of the increased revenue go towards covering these cost with no resulting benefit to consumers? Please discuss.

Response

a) There are many components in uplift costs (i.e. administration fees, ancillary services, congestion management, etc). The uplift components vary according to a range of factors. Also, some are calculated hourly and others on a monthly basis. As such, a simplifying assumption of an average uplift rate of $3.33/MWh based on 2011 values was used. For each tariff scenario, the estimated impact to consumer surplus is the change in export volume relative to the status quo scenario multiplied by the average uplift rate.

b) The assumption is that with increased exports, the uplift would be distributed to all users, via a rate reduction, probably with a lag.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #52 List 1

Issue 23 What is the appropriate level for Export Transmission Rates in Ontario?

Interrogatory

Reference: Exhibit H1, Tab 5, Schedule 2, Appendix B, page 33

a) Is the lntertie congestion revenue discussed here different than the payments that are made to either importers to Ontario or exporters out of Ontario due to transactions that are limited by congestion internal to Ontario?

b) Will the changes in exports/import volumes in the four scenarios considered impact the level of payments to importers/exporters due to internal congestion (e.g., CMSC payments)? If yes, how does the analysis account for the changes in such payments and where (if at all) are they included in the results reported - in terms of both a cost and a benefit?

c) Please comment on who pays the costs of such payments and who receives the benefit in terms of both producers vs. consumers in Ontario and whether the recipients are inside or outside Ontario.

d) If not captured in the analysis, please comment on how the recognition of such payments would affect the results as reported in Tables 12 and 13 (pages 49 & 50).

e) Please provide a schedule sets out the internal congestion payments/revenues (e.g. CMSC) related to imports and exports over the past three 'years. In doing so please report separately those related to imports versus exports and also indicate (in each case) the extent to which those paying/benefitting were in Ontario.

Response

a) In the CRA ETS Study, the Intertie Congestion Revenue on export interties reflects congestion revenue measured by the difference between prices in export markets and Ontario prices adjusted for transaction costs. These payments are not the same as any payments made to generators because of transactions that are limited by congestion internal to Ontario.

b) It was requested that CRA model internal constraints for three Ontario regions. Analysis of the constrained three-region model results indicated that internal congestion in the unilateral elimination scenario would not lead to significant marginal cost differences in an unconstrained vs. constrained dispatch model run. This was also true for EANC (EANC and Unilateral Elimination are the extreme cases.) Therefore, it follows that the CMSC payments in our model runs would be relatively small. Consequently, the changes in CMSC payments between ETS scenarios would be negligible.

c) CRA did not address this issue because, as indicated in b), it found that there was likely to be no material changes in CMSC payments associated with the scenarios examined.

d) See c) above.

e) When internal congestion occurs resulting in CMSC, it cannot be determined if imports and exports have been contributing factors.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #53 List 1

Issue 23 What is the appropriate level for Export Transmission Rates in Ontario?

Interrogatory

Reference: Exhibit H1, Tab 5, Schedule 2, Appendix B, page 33 & 34
Exhibit H1, Tab 5, Schedule 2, page 2 (IESO Response to Stakeholder Questions, June 22, 2012, page 6- posted on IESO web-site)

a) The analysis assumes that all of the lntertie Congestion Revenue related to exports accrues to Ontario. Pleased provide a schedule that for each of the past three years sets out the total intertie Congestion Revenue related to exports and the portion of it that actually accrued to Ontario (producers and/or consumers) as opposed to parties outside of Ontario.

b) Is there intertie congestion revenue/cost associated with imports? If so, how does it arise, who pays and who receives payments and how is it treated in the analysis?

c) If applicable, please indicate what has been the intertie congestion revenue/cost over each of the past three years related to imports and what portion of it was revenue to/costs paid by Ontario producers and/or consumers.

d) If applicable, please estimate the change in intertie congestion revenues/costs related to imports for each alternative for each of the three years analysed.

Response

a) Please see Exhibit I, Tab 23, Schedule 1.04 Staff 87 for an explanation of the difference between Intertie Congestion **Revenue** and Intertie Congestion **Rent.** The table below shows the total Intertie Congestion **Rents** related to imports and exports collected by the IESO for the past three years. Monthly totals are published in IESO's Monthly Market Report.

Year	Total Congestion Rents Collected
2009	$34.6M
2010	$22.9M
2011	$31.2M

b) There is an Intertie Congestion **Revenue** associated with imports. CRA made the assumption that all the Intertie Congestion **Revenue** accrues to the exporting jurisdiction, the Intertie Congestion **Revenue** associated with import congestion was not measured.

c) See table in part a) that shows the total Intertie Congestion **Rents** collected by the IESO for the past three years.

d) See part b)

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #54 List 1

Issue 23 What is the appropriate level for Export Transmission Rates in Ontario?

Interrogatory

Reference: Exhibit H1, Tab 2, Schedule 2, Appendix B, pages 26-27 and 29

a) Is the analysis able to identify that portion of exports that is sourced from imports (i.e, "wheel through transactions")? Is yes, please provide a schedule that for the Status Quo Scenario identifies the total exports in each of the three years modelled and the amount of export sales sourced from imports.

b) Please provide a schedule that breaks down the "changes" in exports per Table 3 showing how much of each change is sourced from a change in Ontario production as opposed to imports.

Response

a)

MWh

Scenario		2013	2015	2017
Status Quo *Nuclear Curtailment*	Total Exports	20,977,195	22,234,111	6,833,429
	Exports sourced from Imports	1,928,395	2,584,043	2,399,606
	Exports less Wheel-Throughs	19,048,800	19,650,068	4,433,823

b)

Exports less Wheel-Throughs (MWh)

Scenario	2013	2015	2017
Status Quo *Nuclear Curtailment*	19,048,800	19,650,068	4,433,823
Unilateral Elimination *Nuclear Curtailment*	24,692,695	19,729,741	4,623,132
Equivalent Average Network Charge *Nuclear Curtailment*	14,179,802	19,639,264	3,868,360
Two-Tiered Scenario A *Nuclear Curtailment*	18,772,678	19,764,320	4,553,078
Two-Tiered Scenario B *Nuclear Curtailment*	20,331,572	19,701,651	4,561,635

Change in Exports, excluding wheel-throughs (MWh)

Scenario	2013	2015	2017
Unilateral Elimination ***Nuclear Curtailment***	5,643,895	79,672	189,309
Equivalent Average Network Charge ***Nuclear Curtailment***	-4,868,997	-10,804	-565,463
Two-Tiered Scenario A ***Nuclear Curtailment***	-276,121	114,252	119,255
Two-Tiered Scenario B ***Nuclear Curtailment***	1,282,772	51,583	127,812

HQ Energy Marketing Inc. (HQEM) INTERROGATORY #1 List 1

Issue 23 What is the appropriate level for Export Transmission Rates in Ontario?

Interrogatory

Reference: General Interrogatory to IESO and Hydro One.

i. The IESO is asked to confirm whether any of the generation capacity currently in operation or in construction in Ontario is, or is expected to be, exported as firm capacity to any neighbouring jurisdiction, tagged as such in NERC e-Tags, and possibly designated as an external network resource or an equivalent installed capacity designation by the external control area. If so, please indicate the quantity of firm exports and to which control area(s).

ii. The IESO and/or Hydro One are asked to advise whether Hydro One has built or plans to build transmission capacity to serve any given level of firm exports and, if so, please advise the cost of this capacity and the level of firm exports served by it.

iii. Please advise of an estimate of the short run marginal cost of transmission service (for clarity, other than marginal losses).

Response

i. There is no generation capacity currently in operation that is exported as firm capacity to any neighbouring jurisdictions. The IESO is not aware of any generation capacity in construction that is expected to be exported as firm capacity to any neighbouring jurisdiction.

ii. The IESO is not aware of any plans to build transmission capacity to serve firm exports.

iii. The IESO has not conducted any analysis of the short run marginal cost of transmission service.

HQ Energy Marketing Inc. (HQEM) INTERROGATORY #2 List 1

Issue 23 What is the appropriate level for Export Transmission Rates in Ontario?

Interrogatory

Reference: Letter from IESO to Hydro One, Exhibit H1-5-2 Appendix B, p. 1 of 102.

i. Please provide all protocols and practices of the IESO with respect to the provision of export service and, in particular, those that address when export services may be curtailed. More specifically, the IESO is asked to provide its emergency operating practices (or references in the relevant market rules and market manuals) when internal transmission constraints or resource adequacy issues require the curtailment of either exports or internal loads.

ii. The IESO is asked to confirm that it has authority to, and does, curtail export and wheelthrough transactions that may create or exacerbate constraints on internal transmission interfaces, such as the ones listed in section 3 of the IESO's *Ontario Transmission System* report (ref.: http://www.ieso.ca/imoweb/pubs/marketReports/OntTxSystem_2012jun.pdf). The IESO is further asked to confirm that it would curtail export and wheel-through transactions before it would curtail loads if doing so would help relieve the internal transmission constraints.

Response

i. Emergency operating practices of the IESO are described in Market Manual 4.3,Sections 2 and 3, and Market Manual 7.4, Appendix E, found at the following:
   - http://www.ieso.ca/imoweb/pubs/marketOps/mo_RealTimeScheduling.pdf
   - http://www.ieso.ca/imoweb/pubs/systemOps/so_GridOpPolicies.pdf

   Market Manual 7.4, Appendix E, lists the actions taken in advance of and during the IESO controlled grid emergency operating state. The curtailment of exports is item #30 on this list and would be undertaken in advance of item #43, which is curtailing non-dispatchable load.

ii. The IESO curtails exports in advance of and during an emergency operating state, as indicated in the above referenced appendix. The appendix also indicates that the IESO may curtail a linked wheeling transaction where the transaction contributes to transmission security concerns or overloads causing either global or local reliability concerns.

HQ Energy Marketing Inc. (HQEM) INTERROGATORY #3 List 1

Issue 23 What is the appropriate level for Export Transmission Rates in Ontario?

Interrogatory

Reference: Export Transmission Tariff Study ("Study"), Exhibit H1-5-2.

i. Please file the responses to questions not addressed in the IESO stakeholder meeting on May 24th, 2012, dated June 22, 2012, (IESO's consultation process SE-94).

Response

i. Responses to questions that were raised but not answered in the IESO stakeholder meeting on May 24th, 2012 were subsequently published on the IESO website on June 22nd, 2012. Please refer to Attachment 1 of this Interrogatory.

Export Transmission Service (ETS) Tariff Study

Responses to Stakeholder Comments and Questions

ieso
Power to Ontario.
On Demand.

Responses to questions not addressed in the stakeholder meeting on May 24th, 2012

1. Can CRA provide friction costs?

   Response:

   Friction costs typically range up to $3/MWh for exports to the regions of interests for this study.

2. What would the impact on the analysis be if Ontario does not join WCI?

   Response:

   Results assuming no carbon pricing in Ontario has been calculated and summarized in an addendum to the report, *Export Transmission Service (ETS) Study*.

3. Are the regional production costs differences material relative to the absolute costs?

   Response:

   In all scenarios and model years, the change in regional production costs is less than 0.15%.

4. Sensitivity of results with respect to:

   a) Participation of Ontario in WCI.

   b) Ability of imports and exports to set prices vs. real time prices set by domestic resources.

   c) Flexibility of hydro to shift.

   d) Changes in natural gas prices.

   e) Expanded ability of nuclear units to maneuver during periods of SBG.

   f) Offer price of nuclear generation.

Response:

In considering sensitivity, one needs to consider both the likelihood that an alternate assumption will be more probable and the likely impact of the alternate assumption on the results of the analysis.

a) Participation of Ontario in WCI

After the presentation of the results of our May 16 report stakeholders asked that alternate model runs be undertaken to determine the impacts of ETS rate and structure changes under the assumption that Ontario does not institute carbon pricing before 2018. The results of this analysis are summarized in an addendum to the report, *Export Transmission Service (ETS) Study*.

In broad terms, the removal of carbon-pricing for Ontario gas-fired generators and of border adjustments for imports from non-WCI markets makes the results more sensitive to changes in ETS rates and structures. Thus, unilateral tariff elimination results in larger export increases in 2015 and 2017, relative to the runs that incorporated carbon pricing. Conversely, an increase in the ETS tariff rate to \$5.80/MWh results in a larger reduction in exports. In terms of impact on net Ontario welfare, the unilateral elimination case becomes more positive in each year, reflecting further increases in producer surplus and export congestion revenue. The results of the Equivalent Average Network Charge (EANC) cases become negative in each year.

b) Exports and Imports Setting Price

CRA examined two possible proxies for HOEP:

- The marginal cost of the resource that is on the margin in each block.
- The equilibrium price reflecting total demand in Ontario, including exports, and supply, including imports.

While the former is, in theory, closer to the price setting process in Ontario, the latter approach provided a closer fit to actual HOEP in Ontario.

The latter approach is similar to, but not identical to, the process through which pre-dispatch prices are set in Ontario. Pre-dispatch prices over the recent past have broadly tracked HOEP and have not shown a consistent bias.

With the former approach and coal-fired generation removed from the mix, prices reflect the marginal cost of the resource on the margin: usually either nuclear at approximately \$8/MWh or CCGT at approximately \$30/MWh. For a variety of reasons including contract structures in Ontario and strategic bidding, this binary pattern is not reflective of the historical pattern of market clearing prices in Ontario.

CRA therefore decided to use the former approach, allowing exports and imports to influence prices in Ontario, fully recognizing that in practice real time prices in Ontario treat exports and imports and fixed and non-dispatchable.

c) Hydro shift assumptions

A range of 17% to 27% of total monthly hydro capacity is assumed to be freely optimizable. With less hydro flexibility, we would not see as much difference between the on-peak and off-peak generation, exports, and HOEP in the Two Tier scenarios.

d) Changes in natural gas prices

CRA used NYMEX futures gas prices for 2013 and EIA forecasts for later years. In our judgment, this approach reflects the best information available at the time. In the time frame of this analysis, gas price movements are likely to affect both base case and scenario outcomes in similar ways. As a result, we do not see significant added value in undertaking further analysis using different gas price assumptions.

e) Additional Nuclear Maneuvering Capability

CRA understand that, subsequent to the analysis, Bruce Power has identified additional maneuvering capability for its nuclear units. In our view, examining the value of these proposals is more properly addressed in the SE-91 Renewable Integration process.

f) Offer Price of Nuclear Units During SBG Events

CRA carried out analysis of two alternate dispatch scenarios under SBG events: nuclear first and wind first. As a result, changing nuclear offer prices would not affect dispatch. CRA also examined the implications of allowing HOEP to fall to zero during SBG events and found that this had very little impact on average HOEP levels.

While sensitivity analysis does provide value, it is important to recognize that there are a limitless number of permutations and combinations that could be modeled and given the complexity of modeling three regions in Ontario and entire North American power system, the cost associated with extensive sensitivity analysis could be prohibitive.

5. Can CRA supply total surplus values? How can consumer surplus values be translated into per MWh amounts?

   Response:

   Only the relative change in surplus between cases could be calculated. To provide an indication of the magnitude and materiality of the impacts of the tariff scenarios relative to the status quo:

   - Producer surplus changes between -0.5% to 0.2% or -\$0.30/MWh to \$0.20/MWh of Ontario generation, and
   - Consumer surplus changes between -0.3% to 0.5% of total payments by consumers or -\$0.20/MWh to \$0.40/MWh of Ontario load

6. How was the EANC of $5.80 determined?

   Response:

   The EANC is based on Hydro One's estimate of the transmission cost of service divided by a forecast of the annual market consumption: $860M divided by 150TWh and rounded up to the nearest dime.

Responses to questions submitted after the stakeholder meeting on May 24th, 2012

1. On page 13 of the report, CRA states that the model was calibrated using 2011 data and it showed that exports were 24.7% less than actual. Given that the purpose of the study is notably to simulate export levels under different price scenarios, isn't CRA concerned by this degree of inaccuracy in the NEEM?

   Response:

   As explained in the report, the model was well calibrated on multiple dimensions. While the overall export levels were low in the model, the distribution of exports was quite realistic. We expect that the changes in the model due to changes in the ETS tariff (i.e., policy impacts) are realistic.

2. Has CRA ever calibrated the model's future year's result against what actually happened in studies for other clients, in order to test the accuracy of the model?

   Response:

   We have not compared past (forward-looking) analyses to actuals (after time elapse). If we did, it wouldn't shed much light on the ETS analysis because we have highly tailored the NEEM model for the current Ontario ETS analysis.

   Instead, we have conducted a calibration to ensure reasonable simulation of the year 2011. Therefore, the future years' analyses are predicated on a calibrated model and assumptions that were vetted with stakeholders.

3. On page 36 of the report, it is stated that in evaluating the Two Tier options, it is assumed that for weekdays 12 hours are peak hours and 12 hours are off-peak hours, and weekends are off-peak. What about holidays? Were they also taken into consideration as being off-peak hours?

   Response:

   We applied the 5x12 definition based on the shape of the load duration curve. Therefore, this question assumes greater specificity than we have the in the load-duration curve model.

4. As part of Proceeding EB-2010-002, the IESO referred to a previous study from CRA on ETS in Exhibit H, Tab 5, Schedule 2 of Hydro One Transmission pre-filed evidence. In that study, it appears the same NEEM was used by CRA. What are the major differences between the study conducted by CRA then and this study, besides that the alternatives explored now include two-tiered options? Are the conclusions of the two studies similar? Is the current NEEM producing more reliable results?

   Response:

   The previous study also had a two-tier option. A difference in the analysis design is that the current study does not have any reciprocal options.

   The current study includes many modeling improvements relative to the previous study, which include:

   - While the overall export levels were better calibrated in the previous study, the distribution of the exports to Ontario's neighbours (both on peak and off peak) are better calibrated in the current study.
   - The HOEP is better calibrated in the current study, including intra-month patterns across load blocks.
   - Our calibration in the current study reflects SBG event patterns (maneuvers and shutdowns) in a realistic manner. For a variety of reasons including the chosen load forecast, we did not detect SBG in the previous calibration or analysis.
   - Our modeling of Ontario hydro is more sophisticated in the current analysis (we have three tranches of hydro in three different Ontario regions).
   - Our current study reflects internal transmission constraints while the previous study did not.
   - The current analysis reflects Ontario's planned renewables build.
   - Our current analysis includes the impact of the Global Adjustment in the welfare calculations, while the previous analysis did not.

5. On page 22, the report mentions: "SBG is invariant to all the ETS Tariff scenarios". Please define SBG, as used in this context.

   Response:

   In this context we have used SBG to refer to the amount of baseload generation in excess of total Ontario demand, inclusive of exports. These SBG events require curtailment to manage the gap between baseload generation and market demand. (Note that this definition of SBG differs from the current IESO definition which refers only to baseload generation in excess of domestic demand in Ontario.)

6. The price (offer) assumptions for all generation that would be called in response to SBG (nuclear, hydro spill, wind curtailment, etc).

   Response:

   Wind an nuclear are assumed to offer at their short-run marginal cost; wind's marginal cost is assumed to be $0/MWh, and the marginal cost of nuclear generation is $8/MWh. Optimizable hydro and run-of-river hydro are assumed to bid their opportunity costs.

   Non-dispatchable run-of-river hydro, NUGs, and solar are assumed to be at the bottom of the stack and are not curtailed in any of the situations studied.

7. Was any compensation included for spilled hydro at OPG's regulated hydro assets in determining the producer surplus?

   Response:

   Yes. The assumption with respect to OPG's regulated assets is that the rates prescribed by the Ontario Energy Board for generation from these assets compensate OPG for its costs, including costs associated with spilled hydro.

8. Clarification of Intertie Congestion Revenue: The Intertie Congestion Revenue calculation as described on page 24 of the report includes subtraction of the ETS tariff, uplift charges and a friction cost. Strictly speaking, these subtracted components should not be included in the intertie congestion revenue if this term is meant to represent the additional rent collected by the IESO when an intertie is congested. Although this may not matter when showing changes in intertie congestion rent since the model assumed these 3 subtracted components are constant, when total intertie congestion rent is reported, the 3 subtracted items should be removed from the calculation of intertie congestion rent.

   Response:

   CRA has used the difference between prices in destination markets and Ontario supply costs (Ontario HOEP plus ETS tariff plus uplift plus friction) as a proxy for Intertie Congestion Revenue in Ontario. As the question above suggests should be done, to calculate the Intertie Congestion Revenue we net the sum of the ETS tariff, uplift, and friction from the difference between the price in the destination market and the Ontario HOEP.

   CRA did not have a ready way of modeling the allocation of the rent associated with such transactions, and consequently considered two approaches: arbitrarily attribute 50% of the intertie congestion revenue associated with both exports and imports to each of the importing and exporting markets, or; allocate all of the revenue to the exporting market, whether it be Ontario exporting into other markets or other markets exporting into Ontario. CRA made the assumption that 100% of congestion revenues at interties accrues to the exporting market; thus when Ontario's export interties are congested, 100% of the associated congestion rents are allocated to Ontario as a benefit, while when Ontario's import interties are congested, 100% of the associated congestion rents are assumed to accrue to the exporting market (and 0% accrues to Ontario).

9. Treatment of Change in Uplift Costs

   Response:

   There are many components in uplift costs (i.e. administration fees, ancillary services, congestion management, etc). Since many of these components vary according to a range of factors, an average uplift rate of $3.33/MWh based on 2011 values was used. Uplift costs are shared by Ontario consumers and exports. With an increase in exports, more uplift revenue would be collected from exporters and reduce the proportion of total uplifts Ontario consumers would pay. Conversely, the opposite happens with Ontario consumers paying a larger proportion of total uplifts when there is a decrease in exports. For each tariff scenario, the estimated impact to consumer surplus is the change in export volume relative to the status quo scenario multiplied by the average uplift rate.

HQ Energy Marketing Inc. (HQEM) INTERROGATORY #4 List 1

Issue 23 What is the appropriate level for Export Transmission Rates in Ontario?

Interrogatory

Reference: Export Transmission Tariff Study ("Study"), Exhibit H1-5-2, Appendix B, p. 5 of 102.

The exhibit states that the author of the Study has assessed proposed options "on the basis of conformance with generally accepted rate-making principles (consistency with neighbouring markets, simplicity, fairness and efficiency)."

i. Please advise who the author of the Study is.

ii. Please provide authority for the statement that "consistency with neighbouring markets, simplicity, fairness and efficiency" are the components of generally accepted rate-making principles. In particular, please advise of an authoritative text where these principles are identified.

iii. Please advise whether the author of the Study agrees that cost causality is a generally accepted rate-making principle.

iv. Please advise whether the author of the Study agrees with the following statement from Bonbright's *Principles of Public Utility Rates* (1988): "Interruptible customers are charged lower rates since they do not have any demand or capacity costs." (at p. 403).

v. Please advise whether the author of the Study agrees with the following statement from Kahn's *The Economics of Regulation* (1998) (Vol. 1): "In the presence of excess capacity, utility companies ought to make every effort to design rates, down to SRMC [i.e., short run marginal cost], to put it to use." (at p. 106).

Response

i. CRA was the author of the Export Transmission Tariff Study.

ii. The four generally accepted rate-making principles were identified in the IESO RFP for this study.

iii. CRA agrees that cost causality is a generally accepted rate making principle.

iv. The scope of the RFP for this study does not require CRA to provide such opinions.

v. The scope of the RFP for this study does not require CRA to provide such opinions.

<u>HQ Energy Marketing Inc. (HQEM) INTERROGATORY #5 List 1</u>

Issue 23 What is the appropriate level for Export Transmission Rates in Ontario?

<u>Interrogatory</u>

Reference: Export Transmission Tariff Study ("Study"), Exhibit H1-5-2, Appendix B, p. 48 of 102.

i CRA describes Vertical Fairness as "ensuring that consumers who impose different costs and derive different benefits are treated in a way that reflects those costs and benefits". Does the IESO agree with CRA's description of Vertical Fairness? If not, please explain.

<u>Response</u>

i. The IESO believes this is an accurate description of the concept of vertical fairness.

HQ Energy Marketing Inc. (HQEM) INTERROGATORY #6 List 1

Issue 23 What is the appropriate level for Export Transmission Rates in Ontario?

Interrogatory

Reference: Export Transmission Tariff Study ("Study"), Exhibit H1-5-2, Appendix B.

i Please confirm that CRA has not made a quantitative comparative assessment of the various criteria considered in the Study (consistency with neighbouring markets, simplicity, fairness and efficiency), that is all criteria were given the same weight.

Response

i. CRA confirms the above statement.

HQ Energy Marketing Inc. (HQEM) INTERROGATORY #7 List 1

Issue 23 What is the appropriate level for Export Transmission Rates in Ontario?

Interrogatory

Reference: Export Transmission Tariff Study ("Study"), Exhibit H1-5-2, Appendix B, pp. 8-14 of 102.

The evidence states that "Where Ontario has excess supply capacity and costs that are competitive with neighbouring markets as in 2013, impacts of changes in the ETS tariff tend to be large" (p.8 of 102). To understand the assumptions used about excess capacity, it is necessary to understand assumptions about both supply and demand. The supply assumptions for 2013, 2015 and 2017 are said to be based on those contained in the Long Term Energy Plan and used by the OPA. (see p.13 of 102). The demand assumptions for 2013, 2015 and 2017 were provided by the IESO (see p. 14 of 102).

i. Please advise of the differences, if any, of the supply assumptions of the LTEP/OPA and those used in the Study.

ii. The LTEP set a target of 10,700 MW of non-hydro renewable energy generation capacity for 2018. The Government's Two-Year FIT Review Report dated March 19, 2012 recommended that the 10,700 MW target be accelerated to 2015.

   a. Please advise which non-hydro renewable energy target is used in the Study.
   b. If the Study uses the 2018 target instead of the 2015 target, please advise why.
   c. Please redo the Study using the 2015 target. If it is not practical to redo the Study, please provide an estimate of the impact of using the 2015 target instead of the 2018 target.

iii. Please provide the demand assumptions provided by the IESO.

iv. Please provide, for 2013, 2015 and 2017 the total nuclear production assumptions, with a breakdown between the Bruce, Darlington and Pickering units, along with the basis for those assumptions.

v. The IESO has provided demand forecasts to the North American Electric Reliability Corporation "NERC") for the periods 2013-2017. The link to this information is at: http://www.nerc.com/files/2011LTRA_Final.pdf.

a. Please advise whether the NERC demand forecasts (or energy usage derived from or consistent with the demand forecasts) were used in the Study.

b. If the Study does not use the NERC demand forecasts (or energy usage derived from or consistent with the demand forecasts), please advise why.

c. Please redo the Study using the NERC demand forecasts (or energy usage derived from or consistent with the demand forecasts). If it is not practical to redo the Study, please provide an estimate of the impact of using the NERC demand forecasts (or energy usage derived from or consistent with the demand forecasts).

Response

i. The supply assumptions used by CRA for the ETS Study are consistent with those used by the OPA and contained in the LTEP.

ii.

a. The non-hydro renewable energy targets used in the ETS Study are consistent with those used by the OPA and contained in the LTEP.
b. CRA's modeling analysis was largely completed by the time of the announcement of the Government's Two-Year FIT Review Report in March 19, 2012. Furthermore, it is unclear from the announcement whether the recommended 2015 target is for supply to be contracted or in-service. Also, given the fact that no new FIT contracts are likely to be tendered until 2013, it is unlikely that FIT projects will be in-service by 2015.
c. CRA did not undertake such an analysis.

iii. The demand information used by CRA was provided by the OPA.

iv. The supply assumptions used by CRA are those used by the OPA in the LTEP. CRA assumed the following total nuclear capacities:

Year	2013	2015	2017
Nuclear Capacity	12,946MW	12,946MW	9,540MW

.

In year 2017, Bruce B and Darlington units would undergo refurbishment.

v.

a. Please note that the NERC forecasts in question are from the 2011 report. The information used in the ETS is more recent, but would be consistent with the NERC forecasts.
b. Please see above response to v) part a).
c. Please see above response to v) part a).

HQ Energy Marketing Inc. (HQEM) INTERROGATORY #8 List 1

Issue 23 What is the appropriate level for Export Transmission Rates in Ontario?

Interrogatory

Reference: Export Transmission Tariff Study ("Study"), Exhibit H1-5-2, Appendix B, p. 28 of 102.

The evidence here and elsewhere identifies the specific drivers for changes in model results for 2015 and 2017 as driven by carbon pricing (in 2015) and nuclear production (in 2017).

i. Please confirm that these factors are the largest drivers in the change in modeling results in 2015 and 2017.

ii. If there are different or additional factors that account for changes in model results in 2015 and 2017, please specify what they are.

iii. Please provide an estimate of the surplus changes that are attributable to nuclear production and other factors identified in the responses to (i) and (ii)

Response

i. This study was conducted within the context of a range of changing circumstances over the 5 year period. While it is impossible to quantify the impact of individual changes in policy or the impacts of specific developments in the external environment, the assumed introduction of carbon pricing in 2015 and taking nuclear plants out of service for refurbishment by 2017 appear to have the greatest impact over the 3 years studied.

ii. Continued expansion of renewable energy investment and the expected implementation of more stringent environmental standards in neighbouring markets also appear to have had a major impact on the results.

iii. As noted above, this study examines the impact of ETS tariff options within an evolving policy environment. It is not a study of the impacts of those policies. As such, it is not feasible to quantify the impacts of such measures.

HQ Energy Marketing Inc. (HQEM) INTERROGATORY #9 List 1

Issue 23 **What is the appropriate level for Export Transmission Rates in Ontario?**

Interrogatory

Reference: Export Transmission Tariff Study ("Study"), Exhibit H1-5-2, Appendix B

i. It is HQEM's understanding that the IESO is proposing to eliminate negative $0/MWh (see IESO's Market Rule amendment proposal MR-00393 at http://www.ieso.ca/imoweb/pubs/mr2012/MR-00393-Q00.pdf). If this proposed change is implemented by the IESO, would it have any impact on the analysis conducted by CRA on the various ETS alternatives? Please explain.prices at external nodes by limiting the settlement value of exports to a net

Response

i. The bidding assumptions used by CRA in the ETS Study precluded negative bids by generators. A policy to eliminate negative bids would therefore not change the results of the analysis.

HQ Energy Marketing Inc. (HQEM) INTERROGATORY #10 List 1

Issue 23 **What is the appropriate level for Export Transmission Rates in Ontario?**

Interrogatory

Reference: Export Transmission Tariff Study ("Study"), Exhibit H1-5-2, Appendix B, pp. 24 and 25 of 102

The CRA study states that the definition of on-peak used in the analysis is 5x12, that is, 12 hours a day, 5 days a week.

i. Please provide the hours comprised in the CRA definition of 5x12 (for example, hour ending 8 to hour ending 19 ; or hour ending 7 to hour ending 18, etc.).

Response

i. CRA applied the 5x12 definition based on the shape of the load duration curve. Therefore, this question assumes greater specificity than CRA had in the load-duration curve model. For a month with four weeks, the top 5x12x4 = 240 hours are considered on-peak. Typically, this meant that one block in each month was comprised of both on-peak and off-peak hours, while all other blocks were exclusively on-peak or exclusively off-peak.

HQ Energy Marketing Inc. (HQEM) INTERROGATORY #11 List 1

Issue 23 What is the appropriate level for Export Transmission Rates in Ontario?

Interrogatory

Reference: Export Transmission Tariff Study ("Study"), Exhibit H1-5-2, Appendix B, pp. 34 to 44 of 102

The CRA study states on page 34 that "[t]he Intertie Congestion Revenue is reported separately, and is allocated to neither producers nor consumers. It is, however, assumed to accrue to Ontario, and is therefore included in the calculation of the change in total surplus in Ontario."

i. The IESO is requested to:
   a. confirm that in the current IESO market design, Intertie Congestion Revenue can be both direct congestion revenues accruing to the IESO (i.e., absent transmission rights sold to market participants) and revenues from the sale of transmission rights by the IESO to market participants.
   b. confirm that in the current IESO market design (see Market Rules, chapter 8, section 4.18 (TR Clearing Account) and chapter 9, section 4.7 (TR Clearing Account Disbursments)), Intertie Congestion Revenue, when redistributed to market participants, is redistributed on the basis of MWh withdrawn from the network.
   c. provide the actual MWh withdrawn from the network in 2010 and 2011by Ontario loads and by exporters respectively.

ii. Given the IESO's answers to 23.0-HQ-11 i-a through i-c above, CRA is requested to:
   a. advise whether Intertie Congestion Revenue should be more appropriately re- classified as a Consumer Surplus component, as opposed to a stand-alone item of the total surplus.
   b. notwithstanding CRA's answer to the interrogatory 23.0-HQ-11-ii-a above, provide updated tables 7 to 10 with Intertie Congestion Revenue re-classified as a Consumer Surplus component, under the WCI and the no-WCI assumptions.

Response

i.

a. Please see response to Exhibit I, Tab 23, Schedule 1.04 Staff 87 for the difference between the Intertie Congestion **Revenue** as calculated in the CRA model and the Intertie Congestion **Rent** as recovered by the IESO.

b. Please see response to Exhibit I, Tab 23, Schedule 1.05 Staff 88, part a).

c. The actual MWh withdrawn by Ontario loads and exporters in 2010 and 2011 are summarized in the table below:

Year	Ontario Load (TWh)	Scheduled Exports (TWh)
2010	139.1	15.2
2011	138.4	12.8

ii.

a. Exhibit I, Tab 23, Schedule 1.05 Staff 88, part a) explains that a portion of the Intertie Congestion **Rent** collected by the IESO is re-distributed to Ontario Consumers. As such it would be appropriate to allocate a portion of the Intertie Congestion **Revenue** to Ontario consumers as Consumer Surplus in the model years and scenarios considered in the CRA study. However, CRA did not estimate how much of the congestion **Revenue** would be allocated to consumers in any of the scenarios considered for the model years 2013, 2015, and 2017.

b. It would only be appropriate to re-classify all of the Intertie Congestion Revenue as a Consumer Surplus component if all of the Intertie Congestion Revenue was forecasted to be re-distributed to consumers in the model years considered in the CRA study. As indicated in the response to a), CRA did not attempt to quantify how much of the Intertie Congestion Revenue has historically been re-distributed to Ontario consumers by the IESO.

HQ Energy Marketing Inc. (HQEM) INTERROGATORY #12 List 1

Issue 23 **What is the appropriate level for Export Transmission Rates in Ontario?**

Interrogatory

Reference: Export Transmission Tariff Study ("Study"), Exhibit H1-5-2, Appendix B, pp. 34 to 44 of 102

On page 33, the notion of "Producer Surplus" is presented as "the change in revenue received by generators less production costs", count taken of the Global Adjustment. CRA is requested to:

i. confirm its understanding that a significant sub-set of the generation capacity in Ontario does not receive compensating Global Adjustment revenues in case of lower prices, and is therefore exposed to real time prices.
ii. confirm its view whether a negative change in producer surplus would fall disproportionately, if not only, on the sub-set of generators which are exposed to low real time prices.

Response

i. CRA confirms the above statement.
ii. CRA confirms the above statement.

HQ Energy Marketing Inc. (HQEM) INTERROGATORY #13 List 1

Issue 23 What is the appropriate level for Export Transmission Rates in Ontario?

Interrogatory

Reference: Export Transmission Tariff Study ("Study"), Exhibit H1-5-2, Appendix B, p. 40 of 102, table 8.

i. CRA is requested to explain the jump in increased consumer surplus from 2013 to 2015 and its fall from 2015 to 2017. Please explain the corresponding variations in producer surplus between 2013 and 2015 and between 2015 and 2017.

Response

i. Table 8 of the ETS Study reports CRA's results for the Equivalent Average Network Charge ("EANC") scenario. With continuing increases in renewable generation between 2013 and 2015, Ontario experiences an increasing number of periods where baseload production exceeds Ontario demand. This excess low-cost supply is exported when possible. In the EANC case, the higher export tariff has little impact on the volume of exports but produces a large increase in export tariff revenue. This is the main component of the increase in consumer welfare in 2015, relative to the status quo case. In 2017, with two nuclear units off-line for refurbishment, exports are substantially lower, in both the base case and the EANC case. In the EANC case the tariff is higher but it applies to a smaller volume of exports, resulting in a smaller increase in ETS tariff revenue and a smaller net gain for consumers. The higher tariff also has a greater negative impact on the volume of exports in 2017 because the exports are primarily higher priced gas-fired generation. This drop in export volumes offsets the gain in ETS tariff revenue.

With respect to producer surplus, the large increase in the ETS tariff in the EANC case leads to a large drop in the market clearing price in Ontario and a corresponding reduction in producer surplus. In the 2017 EANC case, the increased tariff has a smaller impact on Ontario prices and a correspondingly smaller impact on producer surplus.

HQ Energy Marketing Inc. (HQEM) INTERROGATORY #14 List 1

Issues 23 What is the appropriate level for Export Transmission Rates in Ontario?

Interrogatory

Reference: Export Transmission Tariff Study ("Study"), Exhibit H1-5-2, Appendix B, p. 17 of 102.

In its Study, CRA states that "For our analysis, it was assumed that Ontario would join the WCI by 2015. CRA is requested to :

i. confirm that, in CRA Study, the assumption that Ontario would "join the WCI" is actually equivalent to Ontario would "adopt carbon pricing".
ii. confirm that the Government of Ontario has not, to this date, officially announced the implementation of the WCI cap-and-trade regime nor adopted the necessary legislation or regulations to that effect.
iii. given the absence of legislation or regulation from the Province of Ontario officially implementing carbon pricing in Ontario (by formally implementing the WCI cap-and-trade regime or by adopting any other carbon pricing mechanisms), explain the basis for the assumption that Ontario would adopt carbon pricing by 2015.
iv. confirm whether CRA's model takes into account the minimum cost adder of \$2.31/MWh (which would vary depending on the market price of a CO2 ton) that will be charged by the Government of Québec to any purchase of energy from Ontario for import into Québec as per the *Regulation respecting a cap-and-trade system for greenhouse gas emission allowances* decreed by the Government of Québec in December 2011.[1]

Response

i. CRA confirms above statement.
ii. CRA confirms above statement.
iii. Based on consultation with government and stakeholders, it was agreed that assuming a carbon pricing regime in Ontario by 2015 was a reasonable assumption. Recognizing the uncertainty around this assumption and its importance to the analysis, it was agreed that CRA run the model assuming no cap-and-trade before 2018. Both sets of results have been filed with the OEB.
iv. The analysis takes account of the Quebec carbon adder for 2013 in the carbon-pricing case and for all years in the no-carbon-pricing case. The level of this adder in the latter years reflects the carbon intensity of the Ontario electricity sector once the coal-fired plants are closed and projected carbon prices.

HQ Energy Marketing Inc. (HQEM) INTERROGATORY #15 List 1

Issue 23 What is the appropriate level for Export Transmission Rates in Ontario?

Interrogatory

Reference: Export Transmission Tariff Study ("Study"), Exhibit H1-5-2, Appendix B, p. 20 of 102.

In its SE-91 initiative (Renewables Integration), the IESO published a document explaining its propositions regarding floor prices for flexible nuclear resources (ref.: http://www.ieso.ca/imoweb/pubs/consult/se91/se91-20120808-FloorPricesUpdate_r1.pdf). On slide 12 of this document, the IESO lists "Technical Limitations" on flexible nuclear resources.

i. CRA is requested to explain if the technical limitations listed in the above-mentioned document are taken into account in the CRA Study. In particular, CRA is referred to the concept of "average number of units manoeuvred" in Table 1 (p. 20 of 102) of its Study. If the technical limitations listed above are not fully modelled, please explain why, and what the directional impacts of those limitations would be in all ETS Tariff scenarios.

Response

i. CRA's modeling reflects minimum maneuver (4 hours) and shutdown periods (72 hours) as well as the lumpy nature of the nuclear maneuvering (300 MW per unit – maximum of 4 units) and shutdowns (full units). (See page 11 of the report.)

HQ Energy Marketing Inc. (HQEM) INTERROGATORY #16 List 1

Issue 23 What is the appropriate level for Export Transmission Rates in Ontario?

Interrogatory

Reference: Export Transmission Tariff Study ("Study"), Exhibit H1-5-2, Appendix B

i What is the IESO's recommendation with respect to which ETS tariff scenario should be approved by the OEB in this Proceeding ? Please explain the basis for your recommendation.

Response

Please see response to Exhibit I, Tab 23, Schedule 11.01 APPrO 01

Power Workers Union (PWU) INTERROGATORY #18 List 1

Issue 23 What is the appropriate level for Export Transmission Rates in Ontario?

Interrogatory

Ref (1): Independent Electricity System Operator (IESO) News Release, August 23, 2012. IESO to Recommend Limiting Payments to Exports during Negative Prices.

http://www.ieso.ca/imoweb/news/newsItem.asp?newsItemID=6165

The news release advises that the IESO's management will present on September 7, 2012 to its Board of Directors, a market rule amendment to limit payments to exporters during periods of negative energy prices. The proposal would limit the settlement price for energy as well as congestion management settlement credits for export transactions when the intertie zonal clearing price in the applicable zone is negative and the intertie is not import congested.

Ref (2): IESO Export Transmission Service Study, prepared for the IESO by Charles River Associates (Exhibit H1/Tab 5/Sch 2/Appendix B).

a) Please discuss how the assumptions, analyses, and findings of the IESO Export Transmission Service Study in Ref (2) above would be impacted by the recommended market rule amendment Ref (1).

Response

a) Please see response to Exhibit I, Tab 23, Schedule 6.09 HQ 9

School Energy Coalition (SEC) INTERROGATORY #41 List 1

Issue 23 What is the appropriate level for Export Transmission Rates in Ontario?

Interrogatory

[H1-5-1]
Why is the Applicant not seeking to change the ETS Rates?

Response

See the response to interrogatory Exhibit 1, Tab 23, Schedule 1.07 Staff 90.

School Energy Coalition (SEC) INTERROGATORY #42 List 1

Issue 23 What is the appropriate level for Export Transmission Rates in Ontario?

Interrogatory

[H1-5-2]
Please provide any analysis conducted by the Applicant regarding the *Export Transmission Service Tariff Study*, released May 16, 2012.

Response

Hydro One did not conduct any analysis regarding the *Export Transmission Service Tariff Study*.

School Energy Coalition (SEC) INTERROGATORY #43 List 1

Issue 23 What is the appropriate level for Export Transmission Rates in Ontario?

Interrogatory

[H1-5-2-B/p.48]
Please provide a copy of the document titled *Review of Rates in Neighbouring Markets.*

Response

Please refer to Interrogatory Response filed at Exhibit I, Tab 23, Schedule 1.02 Staff 85, Attachment 1.

Consumers Council of Canada (CCC) INTERROGATORY #42 List 1

Issue 23 What is the appropriate level for Export Transmission Rates in Ontario?

Interrogatory

(Hl/T5/S2) Please provide HONI's views on the ETS Tariff Study undertaken by the IESO. From HONI's perspective what is the appropriate level for the ETS Tariff?

Response

The ETS Tariff Study undertaken by the IESO identifies a range of proposed ETS rates and the pros and cons for each proposed rate as directed by the Board in its Decision with Reasons under EB-2010-0002.

Given that export revenues reduce Hydro One’s revenue requirement to be collected through Uniform Transmission Rates, Hydro One recognizes that a higher ETS tariff could reduce Ontario consumer’s transmission delivery costs, if the benefit from a higher ETS tariff is not offset by a decrease in export volumes. However, the ETS Tariff Study demonstrates that changing the ETS tariff will have broader impacts on Ontario consumers, producers and the Ontario electricity market as a whole, and that these impacts can change over time.

Please also refer to response to Exhibit I, Tab 23, Schedule 1.07 Staff 90.

Association of Power Producers of Ontario (APPrO) INTERROGATORY #1 List 1

Issue 23 What is the appropriate level for Export Transmission Rates in Ontario?

Interrogatory

Ref: EB-2010-0002, Exhibit H1, Tab 5, Schedule 2, Pages 5-7
EB-2012-0031, Exhibit H1, Tab 5, Schedule 2, Pages 1-2

In its 2011/2012 transmission rate application, Hydro One Networks Inc. stated the following in its evidence:

> "As the deployment of renewable electricity resources become more prevalent in Ontario, supply is expected to become more variable and exports can help manage such variability through capturing the benefits of resource diversity in the region, as well as potentially contributing to short, intermediate and long-term energy balancing (e.g., by way of better sharing of reserve and regulation through the interties).
>
> In view of this, the IESO concluded that greater value or weighting should be placed on tariff design principles, or an ETS tariff, which will maximize the benefits of integrated regional electricity markets and trades with our neighbours. Accordingly, the IESO found that implementing an ETS tariff such as Option 2 (EANC), while appearing to be attractive from the perspective of increased export revenues, would place downward pressure on export volumes in a climate of lower electricity demands and a future faced by potentially significant increases in variable renewable generation. In the IESO's view, this would not be a prudent decision considering the new reality of the electricity market in Ontario."

The IESO ultimately recommended maintaining the ETS tariff at $1/MWh.

Does the IESO have a recommendation as to the ETS tariff level that would best respond to the Ontario electricity market for the period from January 1, 2013 to December 31, 2014, taking into account the objects of the IESO as set out in the *Electricity Act, 1998* (as amended) and accompanying regulation?

Response

In accordance with the Board's direction, the IESO procured and administered the ETS study. As administrator of the ETS Study, the IESO has not made and is not making a recommendation. The IESO intends to review and consider the evidence – including the evidence to be filed by intervenors – following which the IESO may advocate one of the ETS tariff options.

Association of Power Producers of Ontario (APPrO) INTERROGATORY #2 List 1

Issue 23 What is the appropriate level for Export Transmission Rates in Ontario?

Interrogatory

Ref: Exhibit H1, Tab 5, Schedule 2, Appendix B, Page 22 (Page 13 of Export Transmission Service Tariff Study (ETS Tariff Study))

In the ETS Tariff Study, Charles River Associates (CRA) states:

> "The calibration run detected SBG in 8 months in 2011, while SBG occurred in all 12 month is actuality. The calibration run found nuclear shutdowns in May and June, while in actuality they occurred in May, June, but also August."

a) Please explain the reason(s) why SBG is understated in the calibration run versus the actual SBG occurrences. Please provide the frequency and magnitude of the discrepancy.

b) Please provide the difference between the load block demand and the lowest forecast value in each of the 120 load blocks for the three years included in the ETS Tariff Study.

c) If corrective action is taken to align the model to actual SBG in the calibration run, can its effects on SBG be extrapolated in the forecast results in terms of frequency and magnitude?

Response

a) The table below shows the MWh of energy actually maneuvered or shut down during SBG events in 2011 by month and the 2011 calibration. It is difficult to know why there are discrepancies, however actual power system operation is more complicated than its representation in any model. In real world operation:

- RTOs experience planned and unplanned outages of both transmission lines and generating units. CRA models generator outages but not transmission outages, which tends to overstate transmission capacity;
- internal transmission constraints play a role in limiting total export capacity; and
- there is a lack of coordination between markets in terms of different market time frames (IESO does not have a day-ahead market, while other RTOs do) and in the market pricing at the seams between RTOs.

Some of these factors are captured by the use of friction costs, but the friction costs deal mostly with market participant behavior, not different scheduling procures and physical limitations.

A notable discrepancy is the August 2011 nuclear shutdown. CRA's analysis shows none, however there were actually 64 hours of nuclear shutdown. During the 64 hours, net exports averaged 178 MW, and ranged from import of 853 MW to export of 1,846 MW. Thus CRA modeling with an export limit of 3,000 MW for the lowest blocks and 5,804 MW for other blocks would make it possible to avoid the shutdown of one unit (the data indicates one unit was shutdown).

Nuclear Maneuvers and Shutdowns During SBG Periods
2011 Actual data vs Calibration Results
(MWh)

	Actual		Calibration	
	Maneuver	Shutdown	Maneuver	Shutdown
Jan	14,432	0	0	0
Feb	420	0	0	0
Mar	5,383	0	2,400	0
Apr	24,020	0	38,400	0
May	33,153	111,200	43,200	172,800
Jun	19,612	87,200	43,200	115,200
Jul	4,278	0	0	0
Aug	12,264	51,200	0	0
Sep	103	0	0	0
Oct	21,168	0	4,800	0
Nov	12,840	0	0	0
Dec	5,977	0	7,200	0
TOTAL	**153,650**	**249,600**	**139,200**	**288,000**

b) Attachment 1 shows the maximum load block demand and maximum forecast value as well as the minimum load block demand and minimum forecast value by month for Ontario.

c) Yes - if there was a method for improving the SBG results in the 2011 calibration. However, any improvement would have to be based on basic principles and data, not on particular circumstances of 2011.

Maximum Load Block Demand and Maximum Forecast Value by Month

	2013		2015		2017	
	Forecast Value	**Load Block Value**	**Forecast Value**	**Load Block Value**	**Forecast Value**	**Load Block Value**
Jan	21,562	21,109	21,594	21,333	21,633	21,331
Feb	21,093	20,746	21,202	20,963	21,242	20,956
Mar	19,134	19,807	20,705	20,015	20,520	20,010
Apr	18,389	18,250	18,305	18,442	18,266	18,437
May	20,567	23,808	17,419	24,039	18,695	23,989
Jun	22,105	21,981	22,060	22,196	21,839	22,153
Jul	23,139	24,823	23,010	25,063	22,938	25,007
Aug	20,277	25,571	22,627	25,819	22,419	25,764
Sep	20,747	19,257	20,802	19,454	20,624	19,437
Oct	19,075	17,935	19,492	18,123	19,217	18,121
Nov	20,883	19,032	20,389	19,231	20,967	19,227
Dec	21,844	21,697	21,926	21,920	21,956	21,907

Minimum Load Block Demand and Minimum Forecast Value by Month

	2013		2015		2017	
	Forecast Value	**Load Block Value**	**Forecast Value**	**Load Block Value**	**Forecast Value**	**Load Block Value**
Jan	14,298	13,186	14,278	13,329	14,330	13,339
Feb	14,167	14,186	14,435	14,337	14,360	14,337
Mar	11,874	12,712	13,089	12,849	13,109	12,852
Apr	11,516	11,560	11,897	11,684	11,760	11,684
May	10,703	11,327	10,878	11,445	10,899	11,439
Jun	10,891	11,380	11,088	11,496	11,100	11,487
Jul	11,968	12,347	11,861	12,473	11,844	12,461
Aug	11,912	12,142	12,138	12,267	12,161	12,255
Sep	11,309	11,575	11,960	11,697	11,989	11,691
Oct	11,553	11,613	11,584	11,733	11,609	11,722
Nov	12,633	13,493	12,412	13,635	12,915	13,632
Dec	11,935	12,220	12,084	12,352	12,119	12,357

<u>Association of Power Producers of Ontario (APPrO) INTERROGATORY #3 List 1</u>

Issues 23 What is the appropriate level for Export Transmission Rates in Ontario?

<u>Interrogatory</u>

Ref Exhibit H1, Tab 5, Schedule 2, Appendix B, Page 16 (Page 7 of ETS Tariff Study)

In the ETS Tariff Study, CRA states:

> "Thus, while neighbouring regions do experience the equivalent of SBG, in 2011 limitations on exports do not appear to have been the result of these types of conditions in most SBG hours"

a) Please provide a summary of the likely presence of SBG equivalent conditions in 2013, 2015 and 2017 for the following neighbouring jurisdictions: MISO, NY-ISO, NE, Quebec and PJM.

b) Please provide a detailed summary of the pricing of baseload resources in neighbouring jurisdictions as used in the model for each of the three years modelled (2013, 2015 and 2017).

c) Please provide a histogram of neighbouring markets forecast clearing prices for 2013, 2015 and 2017.

d) What is the IESO's estimate of Ontario's SBG in each year from 2013 to 2017 and what is the IESO's opinion of the SBG conclusions reached by CRA in the ETS Tariff Study?

<u>Response</u>

a) In 2013, equivalent SBG in the neighbouring jurisdictions are primarily projected to occur in May, September and October as the baseload coal capacity in PJM and MISO has to drop to minimum generation levels in the deep off-peak. This is seen to a small extent with baseload natural gas capacity in NY and the Northeast decreasing generation during the deep off-peak times in these months as well. When US environmental regulations beginning in 2015, force the retirement of some baseload coal capacity, CRA modeling anticipates fewer periods of minimum generation levels for the surviving baseload units in the regions neighbouring Ontario, but still occurring in the same low-load months as 2013. Minimum generation periods of baseload capacity in the US will be similar in 2017 as in 2015. CRA does not anticipate SBG equivalent conditions for Quebec.

a) Attachment 1 shows the model bid prices of generating resources with potential to be curtailed under SBG equivalent events, in 2011$ CAD, in each region, in each load block, in each model year. Attachment 1 is available in electronic form only at http://www.hydroone.com/RegulatoryAffairs/Pages/2013-2014Tx.aspx.

b) As part of the ETS Stakeholder Engagement process, stakeholders were consulted and given the opportunity to provide input on the tariff scenarios to be modeled, the metrics to be assessed and the information to be generated. The nature and scope of CRA's ETS study was the result of this process. This interrogatory request would require significant time and effort and it is unlikely CRA could complete this in accordance with the Board's timeline for answering interrogatories. In addition, the information requested is considered by CRA to be proprietary in nature. For these reasons, this and similar interrogatory questions will not be answered.

c) The IESO has conducted SBG analysis for Stakeholder Engagement SE-91-Renewable Integration. The IESO estimate of SBG impacts relates to the over-curtailment of nuclear units by 6.5-8.0 TWh in 2014. No estimates were done for years 2015 to 2017. The IESO considers the SBG conclusions reached by CRA in the ETS Tariff Study to be reasonable.

<u>Association of Power Producers of Ontario (APPrO) INTERROGATORY #4 List 1</u>

Issues 23 What is the appropriate level for Export Transmission Rates in Ontario?

Ref: Exhibit H1, Tab 5, Schedule 2, Appendix B, Page 31 (Page 22 of ETS Tariff Study)

In the ETS Tariff Study, CRA states:

> "It appears that the differentials in baseload variable costs between Ontario sources and US baseload generation, which is mainly coal based, are so large that none of the proposed tariff changes would alter export decisions during SBG events"

Please provide the price of energy for each of Ontario, NY-ISO, MISO, PJM, NE, in each of the load blocks for each year, for each ETS case, for each of the 2 SBG management assumptions. Further, please identify which load blocks are on-peak and off-peak as identified in the study.

<u>Response</u>

As part of the ETS Stakeholder Engagement process, stakeholders were consulted and given the opportunity to provide input on the tariff scenarios to be modeled, the metrics to be assessed and the information to be generated. The nature and scope of CRA's ETS study was the result of this process.

CRA has advised the IESO and HONI that the requested information – i.e., price for energy for each of Ontario, NY-ISO, MISO, PJM, NE, in each of the load blocks for each year – is information which CRA considers to be proprietary and commercially sensitive information. CRA has devoted significant time and effort to compile this information and CRA sells this information to clients (e.g., buyers, sellers of assets) and uses it for the purpose of undertaking various studies for clients (e.g., ETS study). Public disclosure of this information would potentially cause commercial harm to CRA by, among other things, eroding the value of CRA proprietary and adversely affecting CRA's competitive position vis a vis other energy consulting companies.

CRA has advised that it would be willing to produce the requested information, subject to it being filed in confidence with the Board and being made available only to those persons who sign and file Declarations and Undertakings in the form prescribed by the Board's Rules of Practice and Procedure. As such, the requested information has been filed with the Board in confidence.

Association of Power Producers of Ontario (APPrO) INTERROGATORY #5 List 1

Issue 23 What is the appropriate level for Export Transmission Rates in Ontario?

Interrogatory

Ref: Exhibit H1, Tab 5, Schedule 2, page 2
SE-94 – "Responses to questions not addressed in the stakeholder meeting on May 24th, 2012" (June 22, 2012) –
http://ieso.ca/imoweb/pubs/consult/se94/se94-20120622-Responses_to_Stakeholder_Questions.pdf

Upon completing a draft of the ETS Tariff Study, the IESO held a stakeholder meeting on May 24, 2012 where CRA discussed the report's findings and answered questions from stakeholders. Certain stakeholder questions not addressed in this stakeholder meeting were later answered and published on the IESO's website on June 22, 2012. Question #7 and the response read as follows:

> 7. Was any compensation included for spilled hydro at OPG's regulated hydro assets in determining the producer surplus?
>
> Response:
>
> Yes. The assumption with respect to OPG's regulated assets is that the rates prescribed by the Ontario Energy Board for generation from these assets compensate OPG for its costs, including costs associated with spilled hydro.

a) Please provide the hydro energy incrementally spilled relative to the status quo case by month for each of the non status-quo ETS rates.

b) What was the lost revenue to the Ontario Government from reduced Hydro Gross Revenue Charge payments due to spill in the various scenarios and how would these numbers be affected by increased instances of SBG?

Response

a) Attachment 1 shows hydro spillage by month, for each model scenario and model year.

The incremental spill in hydro energy is negligible except for the Equivalent Average Network Charge (EANC) scenario in 2013, where CRA finds an increase in hydro spill of approximately 105,000 MWh. There is a small amount of incremental hydro spillage (vs. status quo) in Ontario in the EANC scenario in 2013 because, with the higher ETS tariff, in some blocks hydro in Northeast Ontario is uncompetitive (after being transmitted through Quebec) with combined cycle gas turbine generation in New York and New England. The charges incurred from Northeast Ontario to Quebec and from Quebec to the northeastern US, together with modeled shadow prices that are incurred along the way (congestion and/or modeled prices in Quebec that exceed variable cost due to netback signals from the US markets), make the Northeast Ontario hydro slightly uncompetitive in New York and New England. In 2015 and 2017, because of higher gas prices, higher demand for electricity, and the closure of coal generation in the US Northeast because of MATS, hydro generation in Ontario becomes more competitive and consequently spillage is reduced (to negligible levels) in these model years.

b) The IESO's data response to questions arising from the stakeholder meeting on May 24, 2012, included the following data on annual hydro spillage by year for each scenario. The revenues lost to government in the form of lower Gross Revenue Charge payments due to incremental spillage in each scenario (relative to the Status Quo), under the assumption that Ontario participates in the WCI by 2015, are shown in the following table (negative values represent losses in GRC payments). Hydro spill may respond to changes in load, but the impact of increased instances of SBG was not modeled by CRA.

Lost Revenue in the Form of Lower Gross Revenue Charge Relative to the Status Quo Scenario (assuming Ontario participates in the WCI)

	2013	2015	2017
Unilateral Elimination	$21	$34	$17
EANC	$(398,832)	$(275)	$61
Two Tier A	$(3)	$22	$32
Two Tier B	$(44)	$(62)	$22

Incremental Hydro Spilling by Month, for each Scenario and Model Year (MWh)
(Assuming Nuclear Curtailment)

		2013	2015	2017
Unilateral Elimination ***Nuclear Curtailment***	**Jan**	2	1	2
	Feb	2	1	0
	Mar	2	9	-2
	Apr	-3	1	5
	May	-1	0	0
	Jun	0	2	1
	Jul	1	0	-3
	Aug	-1	-2	1
	Sep	1	0	2
	Oct	1	-1	0
	Nov	0	-1	-1
	Dec	1	-1	1
Equivalent Average Network Charge ***Nuclear Curtailment***	**Jan**	2	-3	5
	Feb	-6	3	2
	Mar	-2	-49	0
	Apr	-3	4	2
	May	-104,941	-5	1
	Jun	-3	-3	2
	Jul	1	-7	-1
	Aug	0	0	2
	Sep	-1	-2	1
	Oct	-2	-1	0
	Nov	-1	-1	2
	Dec	0	-9	1
Two-Tiered Scenario A ***Nuclear Curtailment***	**Jan**	0	1	0
	Feb	3	2	1
	Mar	-4	-1	-1
	Apr	-1	1	2
	May	0	2	0
	Jun	-2	1	4
	Jul	2	-1	0
	Aug	1	0	2
	Sep	1	0	0
	Oct	-1	0	2
	Nov	1	1	-1
	Dec	-1	1	1
Two-Tiered Scenario B ***Nuclear Curtailment***	**Jan**	-1	-1	1
	Feb	-7	2	0
	Mar	-4	-12	-2
	Apr	-3	0	0
	May	2	-2	0
	Jun	-2	-2	2
	Jul	1	-1	0
	Aug	2	2	1
	Sep	0	3	0
	Oct	0	-1	1
	Nov	0	-1	0
	Dec	0	-3	1

Association of Power Producers of Ontario (APPrO) INTERROGATORY #6 List 1

Issue 23 **What is the appropriate level for Export Transmission Rates in Ontario?**

Interrogatory

Ref: Exhibit H1, Tab 5, Schedule 2, page 2

SE-94 – "Export Transmission Service Tariff Study Review of Rates in Neighbouring Markets" (completed by CRA dated May 16, 2012) - http://ieso.ca/imoweb/pubs/consult/se94/se94-20120516-ETS_Rates_Study-Revised.pdf

In the above-mentioned document completed as part of the SE-94 process, CRA writes:

> "As a result of the need to improve the efficiency of inter-market transactions, FERC has mandated, to the extent practicable, that all inter-market transmission should be eliminated, thus removing the 'pancaking' of rates, which tends to discourage exports and wheeling transactions."

a) In light of the FERC mandate and the actions taken in neighbouring jurisdictions, which ETS tariff rate would most closely match the expected future state of ETS rates in neighbouring jurisdictions?

b) Please provide an update on any actions taken either by the IESO or neighbouring jurisdictions to explore the bilateral elimination of the export tariffs since the decision of the Board in the last Hydro One rate proceeding (EB-2010-0002)?

c) Has the IESO performed any assessment or analysis of the benefit to Ontario when Ontario is importing electricity, if the neighbouring jurisdiction were to have eliminated their export tariff to Ontario?

Response

a) Analysis of which ETS tariff rate would most closely match the expected future state of ETS rates in neighbouring jurisdictions was not done.

b) For the last Hydro One rate proceeding, it was noted that bilateral elimination of the export tariffs requires the agreement of neighbouring jurisdictions and that few neighbouring jurisdictions expressed sufficient interest. Exploring the bilateral elimination of the export tariffs has not been of high priority for the IESO.

c) The IESO has not performed such assessment or analysis.

Association of Power Producers of Ontario (APPrO) INTERROGATORY #7 List 1

Issue 23 What is the appropriate level for Export Transmission Rates in Ontario?

Interrogatory

Ref: Exhibit H1, Tab 5, Schedule 2, Appendix B, Page 32 (Page 23 of ETS Tariff Study)

In the ETS Tariff Study, CRA states:

> "While we have calculated surplus for each group within the economy, it should be recognized that the allocation of that surplus is based on assumptions that are somewhat subjective, particularly in a system with a high degree of government ownership. By way of example, we have treated net income earned by OPG on its non prescribed hydro operations as producer surplus, but that revenue flows to OPG's bottom line, which in turn affects Ontario's fiscal balance to the benefit of Ontario taxpayers/consumers."

Please provide a specific breakdown of the portion of the producer surplus in each of the scenarios that is directly attributable to OPG's non-prescribed hydro production.

Response

For each scenario and for each model year, the change in total Ontario producer surplus is virtually identical to the change in the difference between revenues and production costs for OPG unregulated (ie. non-prescribed) hydro assets. All other generating assets either: i) are contracted at fixed prices with no change in generation between the scenario and the status quo, or; ii) receive a fixed net revenue which is invariant to changes in total generation.

Association of Power Producers of Ontario (APPrO) INTERROGATORY #8 List 1

Issue 23 What is the appropriate level for Export Transmission Rates in Ontario?

Interrogatory

Ref: Exhibit H1, Tab 5, Schedule 2, Appendix B
- Table 7 – Page 36 (Page 27 of ETS Tariff Study)
- Table 8 – Page 40 (Page 31 of ETS Tariff Study)
- Table 9 – Page 43 (Page 34 of ETS Tariff Study)
- Table 10 – Page 44 (Page 35 of ETS Tariff Study)

With respect to the above-mentioned tables:

a) Please provide the results of the study, as shown in Tables 7, 8, 9 and 10, separately for on and off-peak periods as defined in the ETS Tariff Study.

b) Please provide the results of the study, as shown in Tables 7, 8, 9 and 10, separately for on and off-peak periods where on-peak is defined as hours ending 7 to 22.

Response

As part of the ETS Stakeholder Engagement process, stakeholders were consulted and given the opportunity to provide input on the tariff scenarios to be modeled, the metrics to be assessed and the information to be generated. The nature and scope of CRA's ETS study was the result of this process. This interrogatory request would require significant time and effort and it is unlikely CRA could complete this in accordance with the Board's timeline for answering interrogatories. For these reasons, this and similar interrogatory questions will not be answered.

Association of Power Producers of Ontario (APPrO) INTERROGATORY #9 List 1

Issue 23 What is the appropriate level for Export Transmission Rates in Ontario?

Interrogatory

Ref: Exhibit H1, Tab 5, Schedule 2, Appendix B

a) Please provide a cross reference to the study material that supports the following quantities used in the evaluation tables on pages 52 – 55 of Appendix B (pages 43-46 of ETS Tariff Study):

i) On page 52 (page 43 of ETS Tariff Study) under fairness "The net cost to consumers versus the status quo rate in 2013, 2015, and 2017 is $13.5 million, $28.8 million, and $31.5 million, respectively."

ii) On page 53 (page 44 of ETS Tariff Study) under fairness "Reduces costs for Ontario consumers by an annual average of about $50 million per year…"

iii) On page 54 (page 45 of ETS Tariff Study) under fairness "Small net benefit to consumers v. status quo, averaging $3 million per year."

iv) On page 55 (page 46 of ETS Tariff Study) under fairness "Net benefit of $16 million to Ontario consumers in 2013. Little change subsequently."

b) How do the above statements of consumer benefit or cost differ from Consumer Surplus or Net Ontario Benefit?

Response

a) Some of the figures reported on pages 43-46 of the ETS Tariff Study are incorrect. The correct figures are as follows:

i. The last bullet under 'Fairness' on page 43 of the ETS Study should read: "Net cost to consumers versus the status quo rate in 2013, 2015, and 2017 of $16.1 million, $32.6 million and $18.9 million." These figures appear in the *Δ Consumer Surplus* row in Table 7 of the ETS Study.

ii. The last bullet under 'Fairness' on page 44 of ETS Study should read: "Reduces costs for Ontario consumers by an annual average of about $36 million per year…". The average consumer cost reduction referred to in this sentence is calculated as the average of the changes in consumer surplus for the three model years that appear in Table 8 of the ETS Study.

iii. The last bullet under 'Fairness' on page 45 of ETS Study should read: "Small net benefit to consumers v. status quo, averaging $4.4 million per year." The net benefit to consumers referred to in this sentence is calculated as the average of the changes in consumer surplus for the three model years that appear in Table 9 of the ETS Study.

iv. The last bullet under 'Fairness' on page 46 of ETS Study should read: Net benefit to Ontario consumers of $10 million, $4 million and -$0.6 in 2013, 2015 and 2017, respectively." These figures appear in the *Δ Consumer Surplus* row in Table 10 of the ETS Study.

b) These corrected figures represent changes in consumer surplus and are reported in the *Δ Consumer Surplus* rows in Tables 7-10 of the ETS Study.

Association of Power Producers of Ontario (APPrO) INTERROGATORY #10 List 1

Issue 23 What is the appropriate level for Export Transmission Rates in Ontario?

Interrogatory

Ref: Exhibit H1, Tab 5, Schedule 2, Appendix B

Were the additional internal ramp and transmission costs for flowing through one market to inject to another market accounted for in the ETS Tariff Study? For example, the cost to move power from Ontario to PJM via MISO.

Response

Yes. When power is wheeled through a market, CRA imposed all of the transmission charges of the RTO/area providing the wheel through service. These charges are shown in *Export Transmission Service Study Review of Rates in Neighbouring Markets*. Please see Attachment 1 to response of Exhibit I, Tab 23, Schedule 1.02 Staff 85.

Association of Power Producers of Ontario (APPrO) INTERROGATORY #11 List 1

Issue 23 What is the appropriate level for Export Transmission Rates in Ontario?

Interrogatory

Ref: Exhibit H1, Tab 5, Schedule 2, Appendix B

For each of the 3 years covered by the ETS Study, for each of the 5 ETS cases, and for each of the 2 SBG management assumptions, in each of the loads blocks for each year, please provide energy values for: Ontario Demand, Exports, and Supply (Imports, NUGS, Nuclear, Hydro, Non-NUG gas, Coal, Wind, Solar, and Other). Further, please identify which load blocks are on-peak and off-peak as identified in the study.

Response

a) The requested data is contained in Attachment 1, which is is available in electronic form only at http://www.hydroone.com/RegulatoryAffairs/Pages/2013-2014Tx.aspx.

Association of Power Producers of Ontario (APPrO) INTERROGATORY #12 List 1

Issue 23 **What is the appropriate level for Export Transmission Rates in Ontario?**

Interrogatory

Ref: Exhibit H1, Tab 5, Schedule 2, Appendix B

If the Board ordered a change in the ETS tariff level, is it Hydro One's proposal to make any such change effective January 1, 2013?

Response

Yes.

Ontario Energy Board (Board Staff) INTERROGATORY #93 List 1

Issue 24 Are the proposed modifications to the Hydro One transmission connection procedures appropriate?

Interrogatory

Ref: Exhibit A/Tab12/Sch1/p 14
On page 14, Hydro One states:

> *"Connection and integration of renewable generation to the transmission system is relatively new to Hydro One and often requires unique engineering and never done before connection designs which in turn requires significantly more time than traditional load or generator connections to connect. Hydro One requests the Board approve the following typical connection process timeline for new load and generation customers. To this end Hydro One would like to replace the existing table entitled " Hydro One Customer Connection Process Timelines" with the following table:"*

Please identify the number of transmission connections that Hydro One has actually connected since implementation of the Board approved Transmission Connection Procedures, until the date of this Application for the following Transmission Customers ("TCs"):

1) TCs with Conventional Generation Connections
2) TCs with Renewable Generation Connections
3) TCs with Load Connections
4) TCs with mix of 1) and 3)
5) TCs with mix of 2) and 3)

Please comment on the view that for connection of Transmission Customers under categories 1), 3) and 4), it is still workable and appropriate to adhere to the existing Board approved "TIMELINES FOR CONNECTION PROCESS", shown at Section 5 of the Board approved Transmission Connection Procedures for Hydro One Networks Inc.("HONI"), February 12, 2008, (EB-2006-0189).

Response

Table 1 shows all Transmission Connected Load and Generator Connection Projects completed between Feb 2008 and Dec. 2011.

Year	TCs with Conventional Generation Connections (1)	TCs with Renewable Generation Connections (2)	TCs with Load Connections (3)	TCs with mix of 1 and 3 (4)	TCs with mix of 2 and 3 (5)
2008	2	1	6	0	0
2009		2	8	0	0
2010	2	2	8	0	0
2011	1	5	8	0	0

The proposed typical connection timelines are more reflective of the elapsed time for all load and generation connections, than the existing Board approved timelines. The existing timelines as per Table 2 of Exhibit A, Tab 12, Schedule 1 represent only the time for Hydro One activities for each of the phases. These timelines represent best case scenarios. Experience since 2008 with actual connections placed in service or underway has indicated that this is seldom achieved.

The proposed timelines as per Table 3 of Exhibit A, Tab 12, Schedule 1 are more typical elapsed times of each phase including the time taken by connection customers and other parties. It should also be noted that the timelines for some of the phases in Table 2 of the evidence, do not include all the activities that could occur in that phase. For example, in Phase 3 – Connection Estimates, the trigger for the 45 calendar days is from the date that the Electrical Design Package and payment is received; however, there are several steps that take place before this point which can take significant time as it involves several interactions requiring the exchange of both technical and commercial deliverables with the connecting customer.

The proposed typical timelines are expected to cover the majority of connection projects based on the current volume of projects being connected. Experience has shown there will be outliers, with some connections being completed earlier and some later than the typical range. Hydro One submits that providing these typical elapsed timelines will be more helpful to customers to plan for their connections.

Ontario Energy Board (Board Staff) INTERROGATORY #94 List 1

Issue 24 Are the proposed modifications to the Hydro One transmission connection procedures appropriate?

Interrogatory

Ref: Exhibit A/Tab12/Sch1/p12
On page 12, lines 7 to 14, Hydro One states:

> *"In a case where more than one customer triggers the need for a transmission upgrade, a customer may be required to provide an additional security deposit or extend the term of a security deposit after Hydro One has executed Agreements and collected initial security deposits. This would occur when a customer's proportional share of the upgrade cost increases because of other customer projects being delayed or cancelled that would have been contributors to the upgrade as originally planned and calculated in the Agreements".*

(a) Please explain how the modification proposed by Hydro One would be met in a practical and feasible manner by proponents that must arrange for financing well in advance of in-service dates. Has Hydro One considered the implications and added risk that proponents would face under such a new proposed rule?

(b) Please explain how the paragraph proposed to be added under section 2.3 "Additional Security Deposit" would be consistent with section 6.5 of the Transmission System Code.

(c) How does Hydro One confirm by letter (or in some other manner) to proponents/customers that they are the trigger for upgrades? Were more than one customer to trigger an upgrade, does Hydro One confirm for each proponent that additional projects (presumably by size and connection point only) have also been deemed jointly responsible for the same upgrades?

(d) Hydro One addresses the case where projects that share/trigger upgrades are delayed/cancelled, and where Hydro One has proposed collecting an additional security deposit. However, Hydro One has not mentioned if *excess* security deposits would be refunded where *additional* customers seek to connect after the initial customers that triggered made an application and security deposits were estimated. How would Hydro One address this issue?

(e) As an alternative to the proposed new paragraph under the heading *"Additional Security Deposits"*, had Hydro One considered its existing clause of its *Transmission Connection Procedures* under the heading *"Right to Retain All or Part of a Security Deposit"*, which states:

"Hydro One may retain ***all*** *or a part* ***of a security deposit*** *that has been given in relation to the construction or modification of a connection or network facilities in any one or more of the follow circumstances:*

> *(a)* ***Where the customer subsequently fails to connect*** *its facilities to Hydro One's new or modified connection facilities."*(Page 21)
> [emphasis added; sub-clauses "b" through "d" omitted for brevity]

For what reason, if any, would Hydro One be unable to enforce the above clause with respect to customer(s) that have provided a deposit and fail to connect? Please comment on the pros/cons of enforcing existing language versus modifying Hydro One's *Transmission Connection Procedures* document, and also comment on added language and any perverse incentives or disincentives that may result.

Response

a) Prior to executing a CCRA, Hydro One would advise proponents of the estimated total cost of the upgrade and of the possibility that additional security deposit, or an extension to the term of the deposit, may be required in the event another customer project is delayed or cancelled. The amount of the additional security deposit and the scenarios under which such amounts will be required are identified and established in the CCRA. This makes it practical and feasible for proponents to arrange for financing and to assess their financial benefits and risks when it can be identified that more than one customer is triggering an upgrade. It should be noted that if only one party were to trigger an upgrade, that party would be solely responsible for the entire cost of the upgrade. It is a case of favourable circumstances when more than one party is seeking connection in a similar timeframe and requiring the same upgrade so that the cost can be shared between connecting customers.

b) Hydro One has reviewed section 6.5 of the Transmission System Code and finds that it contains no provisions specifically addressing the subject of security deposits. Hydro One assumes that Board Staff may have been referring instead to Section 6.3 of the Code, which does contain a number of provisions pertaining to the treatment of security deposits. Specifically, the subsections are: 6.3.5, 6.3.9, 6.3.10, 6.3.10A and 6.3.11. Hydro One submits that the proposed paragraph ("Additional Security Deposit") is consistent with section 6.3 of the Code, as the provisions in these subsections would continue to apply in situations involving the proposed additional security deposits in the same manner as they would with the original security deposits.

c) The CIA/SIA that is issued to proponents confirms whether they are the trigger for upgrades. Where projects are being evaluated in a similar timeframe, the CIA/SIA also confirms whether additional projects are identified as being jointly responsible for the same upgrades.

d) Excess security deposits would be refunded in that situation.

e) Hydro One acknowledges that, where all connecting customers have executed a CCRA and provided an appropriate security deposit, the existing clause is sufficient to cover the risk to ratepayers by allowing Hydro One to retain the deposit of the customer that fails to connect.

However, Hydro One notes that even in these situations, the fairness of this approach could be called into question in some cases, as the security deposit would then effectively become a form of capital contribution pre-payment, for which, arguably, no benefit is received, contrary to the user pay principle.

In another case where a security deposit has been provided at a particular point in time by all but one customer, and that customer decides to withdraw, the existing clause would not be sufficient to cover the risk to ratepayers, as it would not allow Hydro One to then require additional security deposits from the remaining customers to make up the shortfall.

Although Hydro One recognizes that the risk to ratepayers could be mitigated by obtaining a security deposit from *each* customer for the *full* amount of the estimated total cost of the upgrade, Hydro One is concerned that this approach could pose an excessively onerous financial burden for some customers.

The key issue in Hydro One's view is the growing need for coordination among multiple connecting customers (in particular, renewable generators and concurrent connection projects). Hydro One submits that the proposed new paragraph (*"Additional Security Deposits"*) is needed to help address this important issue.

Ontario Energy Board (Board Staff) INTERROGATORY #95 List 1

Issue 24 Are the proposed modifications to the Hydro One transmission connection procedures appropriate?

Interrogatory

Ref: Exhibit A/Tab12/Sch1/pp 12&13
At this reference, regarding O.Reg 326/09, CIA and SIA interdependence and timing, Hydro One has proposed significant extensions to connection timelines.

> *"For renewable energy projects awarded by the OPA in accordance with OReg 326/09, the joint SIA/CIA phase of the process shall be completed within 150 days* ***after the IESO starts the service guarantee clock for the performance of SIA/CIA studies.****"* (emphasis added)

O.Reg 326./09 s3.(2) states that:

> *"…an application for connection assessment is* ***complete*** *when it contains information sufficient to allow both the IESO and the transmitter to carry out their connection assessment activities."* (emphasis added)

Board staff understands that the transmitter (Hydro One) is responsible for the Customer Impact Assessment, per the TSC, and the IESO is responsible for the System Impact Assessment, per the Market Rules.

(a) Do all renewable energy projects require a CIA?

(b) Do all non-renewable energy projects require a CIA?

(c) Please explain why a "complete" application would not allow both the SIA and CIA to be completed in parallel given that "information sufficient" to allow assessment by both the IESO and transmitter is available for a complete application.

(d) Is there any interdependency between work necessary for the CIA by Hydro One and the SIA by the IESO? Please explain.

(e) In Hydro One's experience how much time lapses from receipt of application until the application is deemed complete by the IESO in terms of the:

i. best case/shortest time elapsed
ii. worst case/longest time elapsed
iii. average time elapsed

(f) Please confirm that O.Reg 326/09 does not use the term "service guarantee clock", and that Hydro One's evidence at Exhibit A/Tab12/Sch1/p.12/lines 20-21 errs in this assertion.

Given that O.Reg 326/09 makes no mention of the term "service guarantee clock", please confirm whether it would be more appropriate and consistent with the language in governing legislation at O.Reg 326/09 for Hydro One to request the following instead of its proposed language at Exhibit A/Tab12/Sch1/pp12-13 of the application:

> *"For renewable energy projects awarded by the OPA in accordance with OReg 326/09, the joint SIA/CIA phase of the process shall be completed within 150 days* ***after the IESO deems the application complete for the purpose of completing SIA/CIA studies."*** (emphasis reflects the deletion and addition of modified language)

(g) On the basis of language in part (f), would the "trigger" language at Table 3 of Exhibit A/Tab12/Sch1/p15 for the start of the Hydro One CIA more accurately be "IESO deems application complete" or similar? How would this affect the time estimate in Table 3 with respect to completion of Phases I & II?

(h) Does O.Reg 326/09 clearly state that the IESO SIA and the Hydro One CIA are activities that cannot be completed in parallel?

(i) If the answer to (a) is "no", please indicate on what basis Hydro One is requesting that these activities be treated as if they were serially dependent activities with respect to generation or load connection projects.

(j) Please explain the meaning of the asterisk at Exhibit A/Tab12/Sch1/p15/Table3/row2.

Response

a) No. The criteria for determining when a CIA is required are set out in section 2.4 of Hydro One's Transmission Connection Procedures (EB-2006-0189)

b) See response to a) above.

c) Hydro One agrees that a "complete" application would allow the SIA/CIA phase to commence. However, the SIA and the CIA can only partially be completed in parallel—this is discussed further in d) below.

d) Yes, the CIA only commences once the SIA work has progressed sufficiently to confirm the system configuration and connection arrangement, typically after the draft SIA report. This is because the SIA can require changes (e.g. identify the need for a new switching station, or configuration modifications) to the originally proposed electrical connection arrangement that needs to be assessed in the CIA.

e) Based on 59 renewable projects that have so far submitted an application to the IESO for a combined SIA/CIA , the time from receipt of application to the application being deemed complete was as follows:

i. best case/shortest time elapsed was 4 days

ii. worst case/longest time elapsed was 547 days

iii. average time elapsed was 89 days. However, the Median time was shorter at 37 days.

f) Hydro One confirms that the term "service guarantee clock" is not used in O.Reg. 326/09. The term "service guarantee clock" was introduced for ease of understanding to help clarify for customers that the 150-day SIA/CIA phase does not actually commence until the customer's application is accepted as "complete" by the IESO and the transmitter, at which time the IESO starts its service guarantee clock for the performance of the SIA/CIA studies. Hydro One has found that this term can be helpful to customers in managing their timelines. The wording proposed by OEB staff is appropriate with one addition emphasized below:

> *"For renewable energy projects awarded by the OPA in accordance with O.Reg 326/09, the joint SIA/CIA phase of the process shall be completed within 150 days after the IESO* ***and the transmitter*** *deem the application complete for the purpose of completing SIA/CIA studies*"

g) No, Table 3 is intended to reflect the typical time lines for all load and generation customer connections. For a non-renewable generation project, or a load connection project, O. Reg. 326/09 does not apply and the trigger for the commencement of the CIA is the completion of the draft SIA.

h) Hydro One submits that this is not stated in the regulation.

i) Please see answer to d) above.

j) The asterisk in Table 3 (Exhibit I, Tab 12, Schedule 1, page 15) was meant to direct the reader to a missing footnote clarifying the 3-5 month time period required for the CIA. The CIA time of 3 months applies essentially to all projects, other than those covered by O. Reg. 326/09, and is triggered by receipt of the draft SIA from the IESO.

The 5 months refer to the 150 days provided in O. Reg. 326/09 for the combined SIA and CIA process. For this process, the 5 month starts from the day the application is deemed complete.

A revised version of Table 3 is provided below to add the missed footnote and to provide some further clarifications. Additional clarification is also provided for the Triggers in Phase 3, 4 and 6.

1. Phase 3: the words "to Date Estimate completed" have been removed
2. Phase 4: the trigger has been changed back to the same description used in Table 2
3. Phase 6: the trigger has been changed to "Signing of Connection Agreement" with a footnote provided for the 30 day commission plan requirement

Table 3
Hydro One Typical Customer Connection Process Timelines (Proposed)

	Typical Timelines	Trigger
Phase 1 – Connection Application	1-2 months	From initial contact to date of completed Customer Joint (SIA/CIA) Application Form
Phase 2 – Customer Impact Assessment (CIA)[1]	3-5 months	From date of IESO Issuing Draft System Impact Assessment (SIA)
Phase 3 – Connection Estimates	4-8 months	From Date Estimate Agreement Executed
Phase 4 – Connection Approval	1 month or longer if regulatory approvals, expropriation and permits are required	From Date of Issuing Draft Connection Cost Recovery Agreement (CCRA) for Customer Signature
Phase 5 – Design & Build	Project Specific (normally 12 to 24 months) To be negotiated with customers as per CCRA terms.	Execution of CCRA
Phase 6 – Commissioning	1-2 months	Signing of Connection Agreement[2]

Notes:

1. For renewable generators, the timeline for combined SIA/CIA process is 150 days (5months) from the completion of the application as per OREG 326/09
2. Customer must submit a commissioning plan to Hydro One 30 days before proposed commissioning tests.

Ontario Energy Board (Board Staff) INTERROGATORY #96 List 1

Issue 24 **Are the proposed modifications to the Hydro One transmission connection procedures appropriate?**

Interrogatory

Ref: Exhibit A/Tab12/Sch1/p 14
Board staff has summarized the information found on pages 14 and 15, Tables 2 and 3 in the table below:

Hydro One Customer Connection Process Timelines

Phase of Project	**Table 2**	**Table 3**	**Extension in Days to Existing**	**Basis for Extension**
(months)		(months)	(days)	
Phase I - Connection Application	0.5	2	45	(A)
Phase II – Customer Impact Assessment (CIA)	3	5	60	(B)
Phase III - Connection Estimates	1.5	8	195	(C)
Phase IV - Connection Approval	1	1	0	-
Phase V - Design & Build	24	24	0	-
Phase VI – Commissioning	1.5	2	15	(D)

(a) In evidence, Hydro cites that “integration of renewable generation […] requires significantly more time than traditional load or generator connections to connect”. Hydro One goes on to request the changes for “new load and generation customers”.

Is Hydro requesting that the extension to connection timelines apply only to renewable generation connections?

(b) If the answer to part (a) is "no", please explain the basis for applying processing extensions for all new *generation* connections, and provide references to Hydro One evidence that provide a basis for these extensions for non-renewable connections.

(c) If the answer to part (a) is "no", please explain the basis for applying processing extensions for all new *load* connections, and provide references to Hydro One evidence that provide a basis for these extensions in the case of non-renewable load connections.

(d) Hydro One has proposed that Phase III be extended from a "best efforts" basis of 45 calendar days to approximately 240 days, representing 195 additional days of processing time.

i. Please provide the amount of time that Hydro One expects it will take to prepare and complete the additional Phase III step of "Execute Pre-CCRA Long lead Items Agreement".

ii. Please provide time estimates for all other activities that contribute to the incremental 195 days to complete Phase III/connection estimates.

(e) For all extensions requested and set out in the Board Staff Table above, please provide an explanation for "Basis for Extension". Please provide particulars of additional activities that are undertaken by Hydro One and the additional time associated with these activities. If the complexity of existing activities has resulted in longer review periods, please provide further explanation.

(f) When did Hydro One first begin advising customers that the timelines at Section 5.0 of the *Transmission Connection Procedures* were unreasonable with respect to the connection of new generation and/or load? Please provide any letter or other communication that Hydro One provided to customers in this regard.

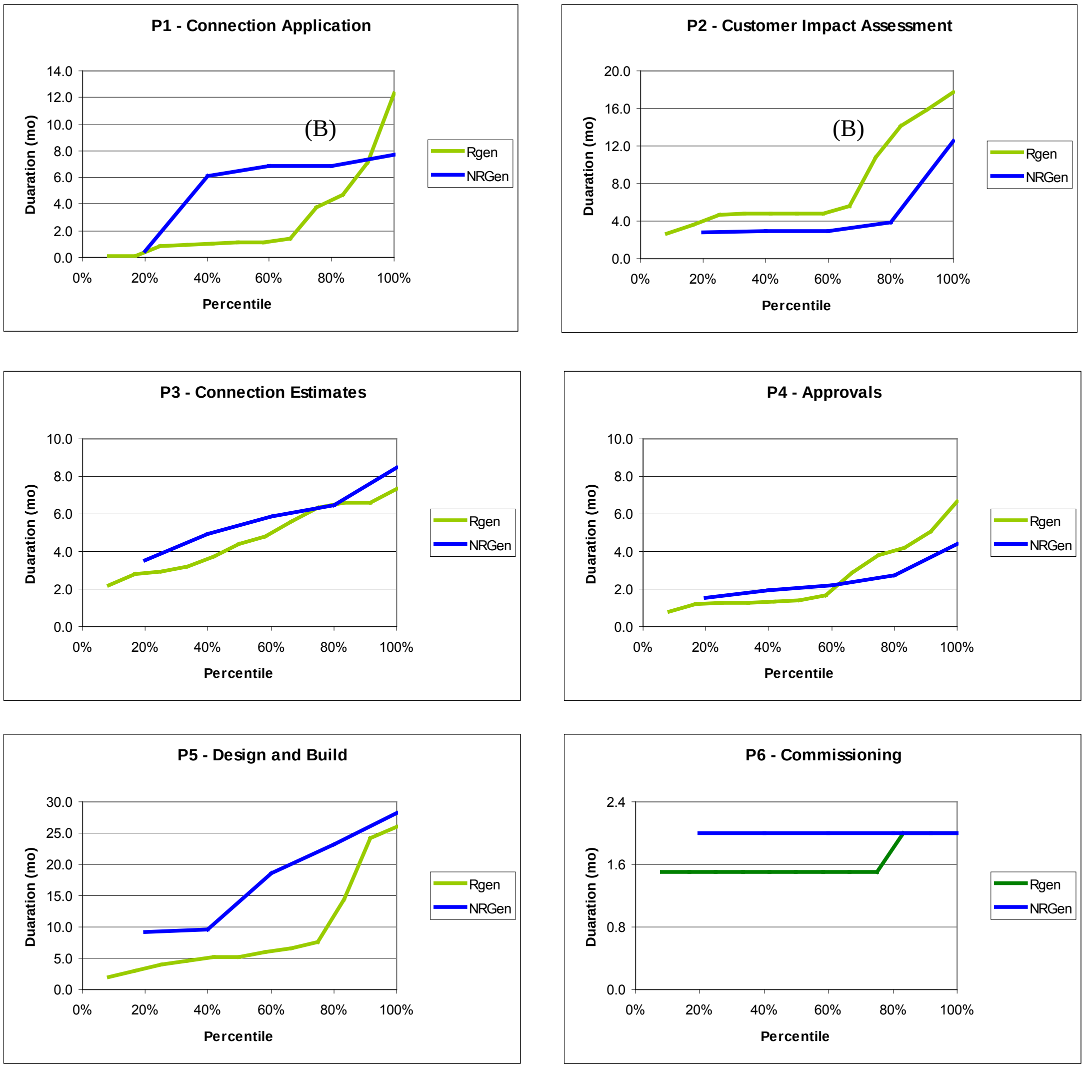
Response

The responses below all refer to the revised Table 3 provided in Exhibit I, Tab 24, Schedule 1.03 Staff 95 part j).

(a) No. The proposed typical timelines are representative of the majority of connections for both generation and load customers.
(b) Hydro One is recommending the proposed typical timelines be adopted based on experience over the last five years for both renewable and non-renewable generation

connections. Figure 1 below shows the duration of time taken for the various connection phases for both types of generation projects that have or are expected to come in service between 2008 and 2013. As noted in Exhibit I, Tab 24, Schedule 1.01 Staff 93, Table 2 and Table 3 in Exhibit A, Tab 12, Schedule 1 are not directly comparable. Table 2 shows only Hydro One time for the activities in each phase and may not show the timeline for all activities for some of the phases. In contrast, Table 3 provides a typical timeline that is more representative of the "elapsed" time for the majority of projects.

Fig. 1 – Timelines for Renewable and Non-Renewable Generation Connections[(A)].



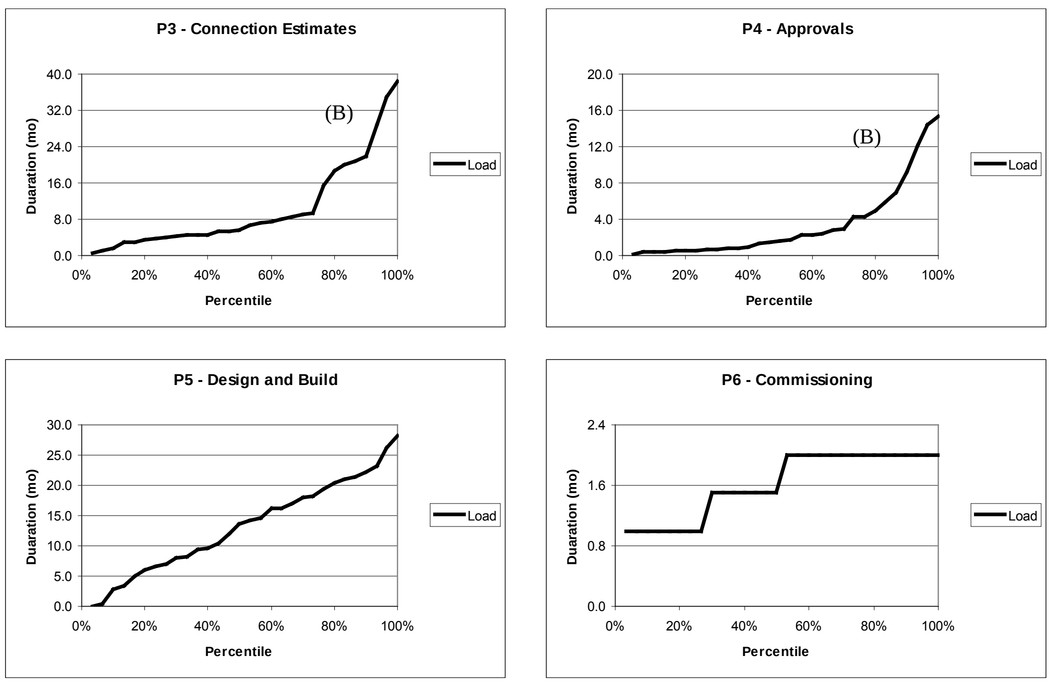
Notes:

A. 12 renewable and 5 non-renewable projects are reported in Fig. 1

B. Those projects outside the typical timeline of 1-2 months for Phase 1 and 3-5 months for Phase 2 are projects that participated in government and OPA RFP procurement programs which required projects to seek preliminary connection applications and connection impact assessments from Hydro One and the IESO prior to submitting their RFP applications. The longer elapsed times represent the time required for this as well as the RFP process, contract award and response from RFP winners that they intend to proceed with the connection.

(c) The proposed typical timelines are also applicable for most load connections. Based on the load connection projects connecting between 2008 and 2013, Phase 1 is typically completed in one month or less and in Phase 2, the CIA is completed in 90 days or less where one is required. For many load connections, a CIA was not required. Figure 2 shows the duration time for Phase 3 to Phase 6 for nearly all load projects connecting between 2008 and 2013.

Fig. 2 – Timelines for Load Connections(A)



(d)

i. Executing the Pre-CCRA Long Lead Items agreement requires 30-60 days. Once the agreement is signed the material can be ordered. We note this activity is conducted in parallel with other activities so in fact it does not impact the overall timeline.

Long–lead time material can require 6 to 24 months to tender, procure and receive. The pre-CCRA long-lead material Agreement allows material to be ordered well in advance of the CCRA being executed, thereby resulting in time savings in Phase 5 (Design and Build) and ensuring that the ratepayer is held harmless in the event that the project does not proceed.

ii. As explained in part (b) and (c) above and in Exhibit I, Tab 24, Schedule 1.01 Staff 93, the proposed typical timelines of 4 to 8 months is more representative of

Notes:

A. 30 load projects are reported in Fig. 2

B. These load projects fall outside the typical timelines for Phase 3 and Phase 4 as they are more complicated projects and can involve approvals (e.g. EA, s92, etc) and/or property acquisition. Many of these projects involve building new transformer stations.

the time required to perform the estimating work for customer connections. Depending on the complexity and the amount of customer interaction required, estimates can take less than 4 or more than 8 months.

(e) The proposed timelines given in Table 3 of Exhibit A, Tab 12, Schedule 1 are typical timelines which vary depending on both project complexity and the responsiveness of the customer when requests for clarification or additional information are made and when a customer wishes to commit to the next phase.

i. For Phase 1, the increase is from 15 days to typically 1 - 2 months. Experience has shown that most customers take at least one month to assemble a “complete” application and many take up to two.

ii. For Phase 2, the requested timeline is increased to 5 months only for renewables projects which are subject to O.Reg326/09. The 5 months includes the combined SIA and CIA process. Other projects will typically take 3 months as also shown in the table.

iii. For Phase 3, the increase is from 1.5 months to typically 4 to 8 months. The data provided in the response to parts b) and c) shows that the majority of projects took typically 4 to 8 months to complete this phase with the exception of the projects noted. Load projects, such as new transformer stations, that involve approvals and/or property acquisition take significantly longer to estimate as the approval and property acquisition work is conducted as part of the estimate phase. This work is more appropriately conducted in the estimating phase in order to confirm project feasibility and work scope before detailed estimates can be provided to the customer. Approvals and property acquisition work involves many interactions with the customer and other parties which can significantly increase the elapsed time.

iv. For Phase 4, no change is requested. Please see the revised Table 3 shown in Exhibit I, Tab 24, Schedule 1.03 Staff 95, part j).

v. For Phase 5, no change is requested.

vi. For Phase 6, the change is from 1.5 months to typically 1-2 months. The average of the typical range given is not changed from the timeline in Table 2 of the pre-filed evidence. As shown in Figure 1 in part b) and Figure 2 in part c), some less complex load projects took 1 month while some more complicated load and generation projects took two months.

(f) Hydro One has informed customers about the typical connection timelines to be expected with every connection request.

i. At initial consultation meetings, both generation and load project customers were informed of a preliminary expected connection timeline consistent with the proposed typical timelines in Table 3. The timelines presented could vary depending on preliminary project scope and anticipated complexity.

ii. During the rollout of the FIT program, Hydro One participated in Webinars that the Ontario Power Authority held. Hydro One also participated at other industry events on renewable generation. The attached slide shows the typical timelines for simple "T-tap" type connections and was shown and described at the events that occurred on:

a. November 20, 2009. – OPA Webinar
b. May 19, 2010 – OPA Webinar
c. Feb 8, 2011 – OSN Conference
d. April 2011 – FIT Forum

Typical timeline to connect to transmission from FIT Contract

<table>
<tr><td>SIA/Customer Impact Assessment application prep.</td><td>1 month</td></tr>
<tr><td>SIA/Customer Impact Assessment</td><td>5 months</td></tr>
<tr><td>Estimate agreement</td><td rowspan="3">6-9 Months</td></tr>
<tr><td>Connection estimates</td></tr>
<tr><td>Preparation of CCRA</td></tr>
<tr><td>Detailed engineering & construction of connection</td><td>9-12 months</td></tr>
</table>

iii. Hydro One provides letters to customers who apply for connection dates that are significantly earlier than what our typical connection timelines would indicate. Attached is a sample of one such letter.

1

Hydro One Networks Inc.
483 Bay Street
North Tower, 15th Floor
Toronto, Ontario M5G 2P5
www.HydroOne.com

Tel: (416) 345-5390
Fax: (416) 345-5406
Email: john.sabiston @hydroone.com

John Sabiston
Manager - Transmission Planning
System Development Division

March 28, 2012

[redacted]

Attention: [redacted]
Project Director

Re: Requested Backfeed Date For [redacted] Wind Energy Centre FIT Project - [redacted]

Dear Mr. [redacted],

Hydro One has reviewed your project requested back-feed date of May 1, 2013 as per your SIA/CIA application for your project. Our view is that your requested back-feed date is very aggressive and unrealistic given the normal timelines associated with Hydro One's performance of the connection work required to connect projects of a similar nature. As such, it is unlikely that Hydro One will be able to meet a May 1, 2013 back-feed date for your project. Typically, the back-feed date for a generation project requiring a Sectionalizing Station and a t-tap connection occurs 24-36 months following the date that Hydro One accepted your fully complete application to connect.

My staff will be continuously monitoring the project timelines and the issues driving them to ensure that your connection is completed as efficiently as possible by Hydro One. During the upcoming project meetings you will be kept informed of the progress of your project.

Notwithstanding the above, Hydro One will commit to a back-feed date for your project only in the Connection and Cost Recovery Agreement (**"CCRA"**) that will be executed by [redacted] Wind Inc.for the project, once Hydro One completes the detailed estimate process. As always, the back-feed date that will be specified in the CCRA is subject o a number of conditions, including, but not limited to, Hydro One being able to appropriate land rights on commercially reasonable terms that Hydro One requires in order to perform the work required to connect the project.

If you have any questions or require further assistance, please do not hesitate to contact me or Michael Lesychyn at 416-345-5954, your project manager.

Yours truly,

HYDRO ONE NETWORKS INC.

John Sabiston,
Manager - Transmission Planning
System Development

Copy to: Michael Lesychyn, Hydro One

Ontario Energy Board (Board Staff) INTERROGATORY #97 List 1

Issue 24 Are the proposed modifications to the Hydro One transmission connection procedures appropriate?

Interrogatory

Ref: Exhibit A/Tab12/Sch1/p 13, Schedule of Charges and Fees
Please provide an estimate of all costs associated with the:

a. Preliminary Engineering Agreement; and
b. Pre-CCRA Letter Agreement for Purchase of Long Lead Items

and indicate any/all assumptions associated with these cost estimates.

Please indicate the confidence interval associated with the "actual costs" of these agreements and if Hydro One will have the ability to change the "actual costs" at any later stage of the connection process. In other words, comment on the risk to the proponent of unforeseen costs at a later stage in the proceeding.

Response

a) and b)
The table below provides these costs

FIT Project Name	Cost of Preliminary Engineering Report ($)	Pre-CCRA Cost for Long Lead Items ($)
Project A	100,000	190,000
Project B	35,000	500,000
Project C	35,000	500,000
Project D	90,000	200,000
Project E	33,900	113,000
Project F	33,900	113,000
Project G	700,000	4,950,000
Project H	33,900	530,000
Project I	30,000	2,000,000
Project J	33,900	1,017,000

Note: The cost of the Pre-CCRA Letter Agreement for Purchase of Long Lead Items is a function of project complexity. The cost and items included in this Agreement is determined via the Preliminary Engineering Agreement (PEA) results that are presented to the proponent.

The cost estimates are of a budgetary nature. These costs are applied towards the overall project costs and become part of the CCRA. At the time the CCRA is executed, the proponent would be aware of any unforeseen costs associated with the preliminary engineering and the long lead items by that point and would be able to make a decision on proceeding.

There is little risk to the proponent as long as the project proceeds. The work under the PEA and the material ordered under the Pre-CCRA Long Lead Items Letter Agreement is ultimately required. Advancing this work reduces the proponent cost and schedule risks by identifying and better anticipating issues that may be encountered during the Phase 5 - Design and Build. It should be noted that the PEA and Pre-CCRA Long Lead Items activities are only conducted with the agreement of the proponent.

Energy Probe (EP) INTERROGATORY #67 List 1

Issue 24 Are the proposed modifications to the Hydro One transmission connection procedures appropriate?

Interrogatory

Ref: Exhibit A, Tab 12, Schedule 1, Page 12 - Security Deposit Procedure

The Evidence states:

> "In a case where more than one customer triggers the need for a transmission upgrade, a customer may be required to provide an additional security deposit or extend the term of a security deposit after Hydro One has executed Agreements and collected initial security deposits. This would occur when a customer's proportional share of the upgrade cost increases because of other customer projects being delayed or cancelled that would have been contributors to the upgrade as originally planned and calculated in the Agreements".

a) Please provide an example of how the additional security deposit would be determined, given the existing security deposit amount and term

b) Has this proposal been stakeholdered with the renewable generation TC community?

c) If so, provide details of this. If not, when will that occur?

Response

a) For an upgrade involving three proponents who are seeking connection in a similar timeframe, an initial security deposit prorated by their respective MW capacities for the cost of the upgrade would be collected from each proponent. In the CCRA for each proponent, requirements for additional security deposits would be identified in advance for scenarios of one or more proponents not proceeding. In the case of one proponent withdrawing, the additional security deposit to cover the balance of the upgrade cost would be required from the remaining two proponents again in a prorated fashion. In this example, should two proponents not proceed, the remaining proponent would be required to provide additional security deposit for the full balance of the upgrade cost. All three proponents are made aware of these scenarios and potential requirements for additional security deposits at the time the CCRA's are executed.

b) No, there has been no prior stakeholdering of this proposed amendment with the generation community. However, when such situations occur Hydro One will advise the affected proponents of the potential opportunity for lower initial security deposits, because other proponents are connecting at the same time, along with the risk for additional security deposits in the event that one or more of the other proponents do not proceed.

c) If the Board determines that such stakeholdering would be helpful, then Hydro One would proceed as directed by the Board. Otherwise, Hydro One will post on its external website any changes that are approved by the Board and inform affected customers accordingly when specific situations occur where upgrades involve more than one customer.

Consumers Council of Canada (CCC) INTERROGATORY #43 List 1

Issue 24 **Are the proposed modifications to the Hydro One Transmission connection procedures appropriate?**

Interrogatory

(Ex. A/T2/S1/p. 3) The evidence states that HONI is requesting Board approval of several proposed modifications to the current Transmission Connection Procedures. How do these procedures relate to the rules regarding connection set out in the Transmission System Code?

Response

The Connection Procedures, which comprise the steps taken by Hydro One to accommodate customer requests for new or modified connections, are consistent with the connection rules set out in the Transmission System Code, as required by section 6.1.3 of the Transmission System Code.

Association of Major Power Consumers in Ontario (AMPCO) INTERROGATORY #20 List 1

Issue 24 **Are the proposed modifications to the Hydro One transmission connection procedures appropriate?**

Interrogatory

a) Has Hydro One consulted with any key stakeholders on the proposed changes to the Transmission Connection Procedures prior to this application? If so, please provide documentation of the consultation process and any written comments received from stakeholders.
b) Please provide any documentation Hydro One may have respecting the length of time for Transmission Connection procedures in other jurisdictions.
c) Please compete the following table of durations for new transmission connections completed in the last three years, or a longer period if that would be more helpful:

Type		Phase 1	Phase 2	Phase 3	Phase 4	Phase 5	Phase 6	Total
Load	Average							
	Range							
Non-Renewable Generation	Average							
	Range							
Renewable Generation	Average							
	Range							

Response

a) Please see the response in Exhibit I, Tab 24, Schedule 1.04 Staff 96, part f) for more details. No written comments from any of the stakeholders were received.

b) Hydro One does not possess any such documentation.

c) Please see the response in Exhibit I, Tab 24, Schedule 1.04 Staff 96, parts b) and c).

Association of Major Power Consumers in Ontario (AMPCO) INTERROGATORY #21 List 1

Issue 24 Are the proposed modifications to the Hydro One transmission connection procedures appropriate?

Interrogatory

Ref: A-12-1 Pages 14 lines 1-6

Preamble:
The stated rationale for the proposed changes to connection procedure timelines appears to be the complexity and learning curve associated with renewable generation. At the same time, the proposed new time lines are for all new load and generation customers.

a) Why are timeline increases needed for customers other than renewable generators?
b) By what other means has Hydro One attempted to meet the existing Board- mandated time lines for Transmission Connection?
c) Would it be acceptable to Hydro One if the increased timelines were applicable only to renewable generation customers? For example, has Hydro one attempted to outsource part of the connection procedure work?

Response

a) Please see the response in Exhibit I, Tab 24, Schedule 1.04 Staff 96, part a), b) and c).

b) Please see response in Exhibit I, Tab 24, Schedule 1.01 Staff 93 for an explanation of the existing timelines in Table 2 and the proposed timelines in Table 3. A revised Table 3 is also provided in the response in Exhibit I, Tab 24, Schedule 1.03 Staff 95. As indicated in Exhibit A, Tab 14, Schedule 1, Hydro One is only entering into agreements with willing proponents to initiate preliminary engineering and/or to order long-lead time materials. A significant portion of these activities can be performed in parallel to shorten the overall connection time.

c) No. Please also see the response in Exhibit I, Tab 24, Schedule 1.04 Staff 96, part a).

   Regarding outsourcing, Hydro One submits that outsourcing has generally not been required given the transmission connection volumes experienced in the last five years. Hydro One looks for opportunities to outsource work to manage the connection workload where appropriate and where it can be done efficiently. For example, Hydro One is currently exploring opportunities for outsourcing work for some of the more complex 500kV connections.

Association of Major Power Consumers in Ontario (AMPCO) INTERROGATORY #22 List 1

Issue 24 Are the proposed modifications to the Hydro One transmission connection procedures appropriate?

Interrogatory

Ref: A-12-1- Table 2 and Table 3

a) Please identify which steps in the Customer Impact Assessment need to be given more time and by how much.

Response

a) Please see the response in Exhibit I, Tab 24, Schedule 1.03 Staff 95.

<u>Association of Major Power Consumers in Ontario (AMPCO) INTERROGATORY #23 List 1</u>

Issue 24 Are the proposed modifications to the Hydro One transmission connection procedures appropriate?

Interrogatory

Ref: A-12-1-Figure 1

a) Is it Hydro One's proposal that the "Preliminary Engineering Agreement" and the "Pre-CCRA Long lead Items Agreement" become part of the final CCRA for purposes of settlement, cost accounting and cost recovery?
b) Please provide samples of the form and format of the proposed Preliminary Engineering Agreement and Pre-CCRA long lead Items Agreement.

Response

a) Yes. Please also see the response in Exhibit I, Tab 24, Schedule 1.05 Staff 97.

b) Please find attached typical agreements as requested. These may require customization to cater to specific projects.

Month Day, Year

STRICTLY CONFIDENTIAL

Proponent Legal Name
Street Address and Suite Number
City, ON Postal Code

Attention: Contact Name

Re: Letter Agreement for Advance Payment towards Preliminary Engineering Design Work Required Prior to the Execution of a Connection Cost Estimate Agreement ("CCEA") – Project Name

Dear Contact Name:

Further to recent discussions between Project's Full Legal Name (the **"Generation Proponent"**) and Hydro One Networks Inc. ("**Hydro One**"), this Letter Agreement documents our agreement with respect to Hydro One performing preliminary engineering design work in respect of the proposed connection of the Generation Proponent's XXX MW proposed Name of Project (the "**Generation Facility**") to Hydro One's transmission system.

The Generation Proponent and Hydro One expect to execute a Connection Cost Estimate Agreement ("**CCEA**") by Date (the "**CCEA Execution Date**") that will define and provide an estimate of the cost of the work to be performed by Hydro One on its transmission system as a result of the proposed connection of the Generation Facility. In the meantime and provided that the Generation Proponent executes this Letter Agreement by Insert Date, 20__ Hydro One agrees to undertake the preliminary engineering work described in Schedule "A" attached hereto and forming a part of this Letter Agreement related to the connection of the Generation Facility to Hydro One's transmission system (the **"Advance Work"**), in advance of the execution of a CCEA and in recognition of the urgency now to move expeditiously towards preparing connection estimates required in order for the parties to execute a Connection and Cost Recovery Agreement ("**CCRA**") that is required to be executed by Hydro One and the Generation Proponent before Hydro One can actually perform work on its transmission system to connect the Generation Facility to Hydro One's transmission system.

The Generation Proponent and Hydro One agree that the Generation Proponent will pay Hydro One an advance payment of $XXX.XX plus Harmonized Sales Tax in the amount of $XXX.XX (collectively, the "**Advance Payment**") upon the execution of this Letter Agreement.

This Letter Agreement will be superseded by the CCEA, on the date the CCEA is fully executed. If the CCEA is executed, the Advance Payment already paid by the Generation Proponent will be credited against the amounts payable by the Generation Proponent under the CCEA. The scope of work in the CCEA and the cost estimate provided under the terms of the CCEA will also include the Advance Work. The Generation Proponent agrees to provide Hydro One with copies of the Generation Proponent's stage I and/or stage II archaeology and environmental baseline studies, which should include information on vegetation, wildlife habitat, local land and resource uses, aquatic features (e.g. creeks, ponds, wetlands etc.), local fish and wildlife information, rare and endangered species and species at risk etc. (collectively, the "**Environmental and Archaeological Reports**") for the area that could be affected by the Hydro One connection facilities to be identified by Hydro One as part of the scope of work in Schedule "A" of this Letter Agreement.

In the event that Advance Payment has been expended by Hydro One, if the connection of the Generation Facility to Hydro One's transmission system does not proceed for any reason or if the Generation Proponent does not execute a CCEA by the CCEA Execution Date, Hydro One shall cease performing the Advance Work. The Generation Proponent understands that the Advance Payment paid by the Generation Proponent does not include any windup costs (plus applicable taxes) which Hydro One may incur in connection with ceasing to perform the Advance Work as described earlier in this paragraph. In such a circumstance, Hydro One would issue a detailed invoice or credit memorandum to the Generation Proponent describing all charges and costs incurred pursuant to this Letter Agreement. The said invoice, less the amount of the Advance Payment already paid by the Generation Proponent, shall be paid by the Generation Proponent within 60 days after invoice date. If the total of all charges and costs incurred prior to termination (plus any windup costs and applicable taxes) is less than the amount of the Advance Payment paid by the Generation Proponent, Hydro One will reimburse the difference to the Generation Proponent within 60 days of the said credit memorandum date.

The Generation Proponent acknowledges that the Advance Work is for the purpose of reducing the time that is required to connect the Generation Facility to Hydro One's transmission system but does not guarantee that Hydro One will meet the Generation Proponent's requested back-feed date or ready for service date. The back-feed date and ready for service date that Hydro One can meet will be determined by Hydro One based on the results of the CCEA and incorporated into the CCRA.

Hydro One shall perform the Advance Work in a manner consistent with Good Utility Practice, in accordance with the requirements of the *Transmission System Code* (as defined below) and in compliance with all applicable laws including, but not limited to, environmental laws, statutes, codes, licensing requirements, treaties, directives, rules, regulations, protocols, policies, by-laws, orders, injunctions, rulings, awards, judgments or decrees or any requirement or decision or agreement with or by any government or government department, commission, board, court authority or agency. Except as provided herein, Hydro One makes no warranties, express or implied with respect to the Advance Work. Hydro One shall not be liable, whatsoever, for any claims, losses, costs, liabilities, obligations, actions, judgments, suits, expenses, disbursements or damages of a party, including where occasioned by a judgment resulting from an action instituted by a third party (the "**Party Losses**") of the Generation Proponent arising out of any act or omission of Hydro One under this Letter Agreement unless such Party Losses result from the wilful misconduct or negligence of Hydro One or any party acting on behalf of Hydro One such as contractors, subcontractors, suppliers, employees and agents. The Generation Proponent shall not be liable, whatsoever, for any Party Losses of Hydro One arising out of any act or omission of the Generation Proponent under this Letter Agreement unless such Party Losses result from the wilful misconduct or negligence of the Generation Proponent or any party acting on behalf of the Generation Proponent such as contractors, subcontractors, suppliers, employees and agents. Neither party shall be liable to the other under this Letter Agreement, whether as claims in contract or in tort or otherwise, for any loss of profits or revenues, business interruption losses, loss of contract or loss of goodwill, or for any indirect, consequential, incidental or special damages, including punitive or exemplary damages. In any event, the total liability of Hydro One to the Generation Proponent for any Party Losses will not exceed the amounts paid by the Generation Proponent under the terms of this Letter Agreement.

This Letter Agreement:

- constitutes the entire agreement between the Generation Proponent and Hydro One respecting the Advance Work and supersedes all prior negotiations, representations, understanding or agreements, written or oral, between Hydro One and the Generation Proponent;

- may only be amended by mutual agreement, in writing, of the parties hereto;

- will terminate upon the execution of the CCEA or as otherwise referred to herein;

- and the Advance Work contemplated herein shall be subject to the terms of the form of connection agreement appended to the *Transmission System Code* as Appendix 1, Version B (the "**Connection Agreement Version B**") regarding the exchange of Confidential Information (as that term is defined in the Connection Agreement Version B), provided that Hydro One agrees that the Generation Proponent may disclose Hydro One's Confidential Information as required for the development of the Generation Facility including to the Generation Proponent's affiliates, joint venture partners and their respective affiliates, any governmental authority including the Ontario Power Authority, the IESO, any LDC and its affiliates, or any consultants, agents, potential financing sources, or legal, financial or professional advisors (collectively, the "**Third Parties**") subject to the Generation Proponent taking all precautions as may be reasonable and necessary to prevent unauthorized use of Hydro One's Confidential Information by such Third Parties. The Generation Proponent is solely responsible to ensure that the Third Parties are bound by the confidentiality terms of this Letter Agreement and that the Generation Proponent shall defend, indemnify and hold harmless Hydro One from and against all suits, actions, damages, claims and costs arising out of any breach of the confidentiality terms of this Letter Agreement by any one or more of the Third Parties;

- shall be governed by and construed in accordance with the laws of the Province of Ontario and the laws of Canada applicable therein, and the parties hereto irrevocably attorn to the exclusive jurisdiction of the courts of the Province of Ontario in the event of a dispute hereunder; and

- may be executed in counterparts, including facsimile counterparts, each of which shall be deemed an original, but all of which shall together constitute one and the same agreement.

All capitalized terms that appear in this Letter Agreement without definition shall have the meaning ascribed to such term in the Transmission System Code, the code of standards and requirements issued by the Ontario Energy Board on June 10, 2010, as it may be amended, revised or replaced in whole or in part from time to time (the "**Transmission System Code**").

[EXECUTION PAGE FOLLOWS]

The parties agree that this letter accurately reflects the understanding reached by Hydro One and the Generation Proponent with respect to the Advance Work and the Advance Payment. The receipt and sufficiency of the consideration exchanged for this Letter Agreement is acknowledged and the intent of the parties to be bound by this agreement is confirmed by the signature by their duly authorized representatives below.

HYDRO ONE NETWORKS INC.

____
John Sabiston
Manager – Transmission Planning
I have the authority to bind the Corporation

USE IF THE GENERATION PROPONENT IS A LIMITED PARTNERSHIP/L.P. (and DELETE all other not-applicable applicant sections):

[INSERT FULL LEGAL NAME OF GENERATION PROPONENT LP],
by its general partner, INSERT FULL LEGAL NAME
OF GENERAL PARTNER

____
Name:
Title:

____
Name:
Title:
I/We have the authority to bind the corporation.
The corporation has the authority to bind the Limited Partnership.

USE IF THE GENERATION PROPONENT IS AN INDIVIDUAL (and DELETE all other not-applicable applicant sections):

SIGNED, SEALED AND DELIVERED
in the presence of:

____________________________ ________________________________(signature)
Witness **Proponent**

USE IF THE GENERATION PROPONENT IS A CORPORATION (and DELETE all other not-applicable applicant sections):

[FULL LEGAL NAME OF GENERATION PROPONENT]

____
Name:
Title:

Schedule A – Preliminary Engineering Related to the Connection of the Generation Facility (Advance Work)

Hydro One will provide preliminary engineering services to support the connection of the Generation Facility which may include one or more of the following activities:

1. Review the connection requirements to implement the connection of the Generation Facility to Hydro One's XX kV XXX circuit between Hydro One's Insert Name TS and Hydro One's Insert Name TS, approximately XX km from Hydro One's Insert Name TS (such as station equipment ratings, telecommunication interfaces, protection and control systems, protection and control systems, station infrastructure or telemetering systems), including, any upgrades to the transmission system that may be required to facilitate the connection of the Generation Facility to Hydro One's transmission system.
2. Determine the location of Generation Facility connection along XXX as well as the feasibility of the Generation Proponent's proposed YY kV tapping configuration in respect of the Generation Proponent's transmission line.
3. Conduct site visits if required and review the location of the line tap and the existing structures.
4. Identify the most likely location of the Hydro One connection facilities along XXX and feasibility of the Generation Proponent's proposed YY kV tapping configuration (plus any associated construction access and laydown areas) as well as the areas to be included in the Environmental and Archaeological Reports to be performed by the Generation Proponent that Hydro One will be relying on to complete its own environmental approvals.
5. Meet with the Generation Proponent's engineering staff and consultants as required, to review the proposed conceptual design.
6. Prepare a summary of the work completed which is to be incorporated into the scope of work for the CCEA.

Month, Day, Year

STRICTLY CONFIDENTIAL

Legal Name of Generation Proponent
Street
City, Province
Postal Code

Attention: Contact Name – Contact Title

Dear Contact Name,

Re: Pre-CCRA Letter Agreement for Advance Payment of Engineering Design Work and Procurement of Certain Equipment Prior to Execution of a Generation Facility Connection and Cost Recovery Agreement – Name of Project

Further to recent discussions between Legal Name of Generation Proponent (the "**Generation Proponent**") and Hydro One Networks Inc. ("**Hydro One**"), this Pre-CCRA Letter Agreement documents our agreement with respect to Hydro One performing certain work related to the connection of the Generation Proponent's ___ MW wind power/solar power generating facility located at describe location, Ontario (the "**Generation Facility**") to Hydro One's transmission system.

Based on the submissions made by the Generation Proponent and on the IESO's System Impact Assessment (SIA) draft report of Insert Date, Year, and Hydro One has conducted a Customer Impact Assessment (CIA) study and issued the draft CIA report on Insert Date, Year.

Hydro One and the Generation Proponent executed a Connection Cost Estimate Agreement on Insert Date, Year, (the "**Estimate Agreement**") wherein Hydro One will prepare and provide the Generation Proponent with a release quality estimate for the work necessary to connect the Generation Facility to Hydro One's transmission system.

The Generation Proponent and Hydro One expect that the Connection and Cost Recovery Agreement (the "**CCRA**"), which is required to be executed by Hydro One and the Generation Proponent before Hydro One can actually perform work on its transmission system to connect the Generation Facility to Hydro One's transmission system, to be executed by no later than Insert Date, Year (the "**CCRA Execution Deadline**").

Provided that this Pre-CCRA Letter Agreement is executed by Insert Date, Year, in recognition of the urgency of undertaking work now for the procurement of line tap structures, required protections, telecom and other equipment as required (describe addition equipment as required) (the "**Equipment**") that will be required to be installed in order to connect the Generation Facility, the Generation Proponent and Hydro One have agreed that the Generation Proponent will pay Hydro One upon execution of this Pre-CCRA Letter Agreement, as an advance payment against the total amounts payable under the terms of the CCRA, the sum of $Insert Amount (plus HST) (the "**Advance Payment**") in order for Hydro One to undertake detailed engineering design and procurement of the Equipment (collectively, the "**Pre-CCRA Work**") for the above referenced connection in advance of the execution of the CCRA by the parties. Hydro One will charge the Generation Proponent Hydro One's standard rates plus Hydro One's standard overheads together with applicable taxes thereon in respect of the Pre-CCRA Work.

This Pre-CCRA Letter Agreement will be superseded by the CCRA, on the date the CCRA is executed by the Generation Proponent and Hydro One. When the CCRA is executed, the Advance Payment already paid by the Generation Proponent will be credited against the amounts payable by the Generation Proponent under the terms of the CCRA. The scope of work and the cost estimate in the CCRA will also include Pre-CCRA Work.

In the event that Advance Payment has been expended by Hydro One, if the connection of the Generation Facility to Hydro One's transmission system does not proceed for any reason or if the Generation Proponent does not execute a CCRA by the CCRA Execution Date, Hydro One shall cease performing the Pre-CCRA Work. The Generation Proponent understands that the Advance Payment paid by the Generation Proponent does not include any windup costs (plus applicable taxes) which Hydro One may incur. In such a circumstance, Hydro One would issue a detailed invoice or credit memorandum to the Generation Proponent describing the charges and costs associated with, related to or incurred with respect to the Pre-CCRA Work. The said invoice, less the amount of the Advance Payment already paid by the Generation Proponent, shall be paid by the Generation Proponent within 60 days after invoice date. If the total of all charges and costs associated with, related to or incurred with respect to the Pre-CCRA Work prior to termination (plus any windup costs and applicable taxes) is less than the amount of the Advance Payment paid by the Generation Proponent, Hydro One will reimburse the difference to the Generation Proponent within 60 days of the said credit memorandum date.

The Generation Proponent acknowledges that the Pre-CCRA Work is for the purpose of reducing the time that is required to connect the Generation Facility to Hydro One's transmission system but does not guarantee that Hydro One will meet the Generation Proponent's requested back-feed date or ready for service date. The back-feed date and ready for service date that Hydro One can meet will be determined by Hydro One based on the results of the Estimate Agreement and incorporated into the CCRA.

Hydro One shall perform the Pre-CCRA Work in a manner consistent with Good Utility Practice, in accordance with the *Transmission System Code* (as defined below) and in compliance with all applicable laws including, but not limited to, environmental laws, statutes, codes, licensing requirements, treaties, directives, rules, regulations, protocols, policies, by-laws, orders, injunctions, rulings, awards, judgments or decrees or any requirement or decision or agreement with or by any government or government department, commission, board, court authority or agency. Except as provided herein, Hydro One makes no warranties, express or implied with respect to the Pre-CCRA Work. Hydro One shall not be liable, whatsoever, for any claims, losses, costs, liabilities, obligations, actions, judgments, suits, expenses, disbursements or damages of a party, including where occasioned by a judgment resulting from an action instituted by a third party (the "**Party Losses**") of the Generation Proponent arising out of any act or omission of Hydro One under this Pre-CCRA Letter Agreement unless such Party Losses result from the wilful misconduct or negligence of Hydro One or any party acting on behalf of Hydro One such as contractors, subcontractors, suppliers, employees and agents. The Generation Proponent shall not be liable, whatsoever, for any Party Losses of Hydro One arising out of any act or omission of the Generation Proponent under this Pre-CCRA Letter Agreement unless such Party Losses result from the wilful misconduct or negligence of the Generation Proponent or any party acting on behalf of Generation Proponent such as contractors, subcontractors, suppliers, employees and agents. Neither party shall be liable to the other, whether as claims in contract or in tort or otherwise, for any loss of profits or revenues, business interruption losses, loss of contract or loss of goodwill, or for any indirect, consequential, incidental or special damages, including punitive or exemplary damages. In any event, the total liability of Hydro One to the Generation Proponent for any Party Losses will not exceed the amounts paid by the Generation Proponent under the terms of this Pre-CCRA Letter Agreement.

Should the Generation Proponent sell, lease or otherwise transfer or dispose of the Generation Proponent's interest in the proposed Generation Facility to a third party, the Generation Proponent shall cause the purchaser, lessee or other third party to enter into an assumption agreement with Hydro One to assume all of the Generation Proponent's obligations in this Pre-CCRA Letter Agreement; and notwithstanding such assumption agreement unless Hydro One agrees otherwise, in writing, the Generation Proponent shall remain obligated under the terms of this Pre-CCRA Letter Agreement.

This Pre-CCRA Letter Agreement:

- constitutes the entire agreement between the Generation Proponent and Hydro One respecting the Pre-CCRA Work and supersedes all prior negotiations, representations, understanding or agreements, written or oral, between Hydro One and the Generation Proponent;

- may only be amended by mutual agreement, in writing, of the parties hereto;

- will terminate upon the execution of the CCRA or as otherwise referred to herein;

- and the Pre-CCRA Work contemplated herein shall be subject to the terms of the form of connection agreement appended to the *Transmission System Code* as Appendix 1, Version B (the "**Connection Agreement Version B**") regarding the exchange of Confidential Information (as that term is defined in the Connection Agreement Version B) provided that Hydro One agrees that the Generation

Proponent may disclose Hydro One's Confidential Information of Hydro One as required for the development of the Generation Facility including to the Generation Proponent's affiliates, joint venture partners and their respective affiliates, any governmental authority including the Ontario Power Authority, the IESO, any LDC and its affiliates, or any consultants, agents or legal, financial or professional advisors (collectively, the "**Third Parties**") subject to the Generation proponent taking all precautions as may be reasonable and necessary to prevent unauthorized use of Hydro One's Confidential Information by such Third Parties. The Generation Proponent is solely responsible to ensure that the Third Parties are bound by the confidentiality terms of this Letter Agreement and that the Recipient shall defend, indemnify and hold harmless Hydro One from and against all suits, actions, damages, claims and costs arising out of any breach of the confidentiality terms of this Letter Agreement by any one or more of the Third Parties;

- shall be governed by and construed in accordance with the laws of the Province of Ontario and the laws of Canada applicable therein, and the parties hereto irrevocably attorn to the exclusive jurisdiction of the courts of the Province of Ontario in the event of a dispute hereunder; and

- may be executed in counterparts, including facsimile counterparts, each of which shall be deemed an original, but all of which shall together constitute one and the same agreement.

All capitalized terms that appear in this Pre-CCRA Letter Agreement without definition shall have the meaning ascribed to such term in the Transmission System Code, the code of standards and requirements issued by the Ontario Energy Board on July 25, 2005 that came into force on August 20, 2005 as published in the Ontario Gazette, as it may be amended, revised or replaced in whole or in part from time to time ("**Transmission System Code**").

[SIGNATURE PAGE FOLLOWS]

The parties agree that this letter accurately reflects the understanding reached by Hydro One and the Generation Proponent with respect to the Pre-CCRA Work and the Advance Payment. The receipt and sufficiency of the consideration exchanged for this Pre-CCRA Letter Agreement is acknowledged and the intent of the parties to be bound by this agreement is confirmed by the signature by their duly authorized representatives below.

HYDRO ONE NETWORKS INC.

____
Name:
Title:
I have the authority to bind the Corporation

USE IF THE GENERATION PROPONENT IS A LIMITED PARTNERSHIP/L.P. (and DELETE all other not-applicable applicant sections):

[INSERT FULL LEGAL NAME OF GENERATION PROPONENT LP],
by its general partner, INSERT FULL LEGAL NAME
OF GENERAL PARTNER

____
Name:
Title:

____
Name:
Title:
I/We have the authority to bind the corporation.
The corporation has the authority to bind the Limited Partnership.

USE IF THE GENERATION PROPONENT IS AN INDIVIDUAL (and DELETE all other not-applicable applicant sections):

SIGNED, SEALED AND DELIVERED
in the presence of:

_________________________ (signature)	_________________________
Witness	**Proponent**

USE IF THE GENERATION PROPONENT IS A CORPORATION (and DELETE all other not-applicable applicant sections):

[FULL LEGAL NAME OF GENERATION PROPONENT]

____
Name:
Title:
____

Association of Major Power Consumers in Ontario (AMPCO) INTERROGATORY #24 List 1

Issue 24 Are the proposed modifications to the Hydro One transmission connection procedures appropriate?

Interrogatory

Ref: A-12-1- Figure 1
Ref: A-12-1 Tables 2 & 3

a) The trigger for Phase 3 Connection Estimates is changed between Tables 2 & 3 from "Electrical Design Package Received and Payment Received," to "From Date Estimate Agreement Executed to Date Estimate Completed"
b) In what step on Fig lis found the trigger event stated in Table 2?
c) Is the "Estimate Agreement" referred to in Table 3 the same as the "Preliminary Engineering Agreement proposed on Fig 1? Please explain if this is not correct.

Response

a) Yes. Please see the revised Table 3 in Exhibit I, Tab 24, Schedule 1.03 Staff 95, part j) for further clarification.

b) The bullet in Figure 1 which reads "Review Customer Connection Electrical Design Package" refers to the trigger event stated in Table 2.

c) No. The Estimate Agreement listed under the Trigger for Phase 3 is in fact the Connection Cost Estimate Agreement (CCEA) and is referred to in the second bullet (Agree on Estimate Scope of Work) listed under Phase 3 in Figure 1. The Preliminary Engineering Agreement in Figure 1 is a parallel activity that can be started, subject to agreement by the customer, partway through Phase 2. This enables scope development activities with the customer to occur prior to the start of the formal estimating process (Phase 3).

Ontario Energy Board (Board Staff) INTERROGATORY #98 List 1

Issue 25 **Have all impacts of the conversion of regulatory and financial accounting from CGAAP to USGAAP been identified, and reflected in the appropriate manner in the Application, the revenue requirement for the Test Years and the proposed rates?**

Interrogatory

Ref: EB-2011-0268 Response to Board Staff Interrogatory #21
In Board Staff Interrogatory #21, EB-2011-0268, Hydro One was asked to describe the differences between CGAAP and US GAAP that would be incorporated into the Impact for USGAAP Regulatory Account. In the response to this interrogatory, Hydro One stated that it had not yet identified any significant differences that would be recorded in this account.

a) Has Hydro One identified any significant differences between CGAAP and USGAAP at this time? Please explain.

b) Please explain if any of the differences noted in the answer to part a) of this interrogatory would be incorporated into the Impact for USGAAP regulatory account or the proposed revenue requirements for 2013 and 2014.

Response

a) Hydro One has still not identified any significant differences as at the second quarter of 2012 that would be recorded in this account. The account is to accommodate the impact of any CGAAP versus US GAAP differences that impact Hydro One Transmission’s 2012 revenue requirement.

b) N/A.