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

Interrogatory

Issue 1.1: Has Hydro One responded appropriately to all relevant Board directions from previous proceedings

Reference: Exhibit A/Tab 16/Schedule 1/Page 1 Table 1

a) Does Hydro One agree/disagree that the evidence on Issue iii) Key Performance Indicators and Cost Allocation Accounting Processes is fully compliant with this Directive?
b) Provide a list of evidentiary references on this issue including, but not limited to Exhibit A, Tab 14, Schedule 1.

Response

a) Hydro One agrees that it is compliant with this directive. Hydro One continues to develop Key Performance Indicators to measure against and drive improvements in efficiency. Hydro One's current list of Key Performance Measures can be found in Exhibit I, Tab 9, Schedule 15.

b) See part a) above.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #2 List 1

Interrogatory

Issue 1.2: Are Hydro One's economic and business planning assumptions for 2011/2012 appropriate?

Reference: Exhibit A/Tab12/Schedule1/Appendix A/Page 1

a) Provide a copy of the February 2010 Business plan approved by the Hydro One Board.
b) Provide a variance report for 2009-2012 actual and forecast Economics, Interest rates, Labour rates and Payroll Burden that shows the major changes from the Approved Business Plan underpinning Hydro One Networks' 2009/2010 Transmission Rate Application.

Response

a) Please refer to Exhibit I, Tab 3, Schedule 1.

b) The tables below show the changes between the 2009-12 actual and forecast as submitted in this application and Hydro One Networks' 2009-2010 Tx Rate Application.

ECONOMICS

	2009	2010	2011	2012	2013
CPI – Ontario (%)	-1.3	0.0	-0.1	0.0	0.0
Tx cost escalation for Construction (%)	1.6	-0.8	-1.5	-1.9	-0.3
Tx cost escalation for Operations & Maintenance (%)	2.2	0.7	0.1	0.2	0.0
Dx cost escalation for Construction (%)	-0.1	0.2	-0.6	-0.6	-0.5
Dx cost escalation for Operations & Maintenance (%)	3.1	0.4	-0.1	-0.2	0.0
Exchange Rate (CDN$/US$)	0.143	0.090	0.009	-0.021	-0.039

INTEREST RATES

	2009	2010	2011	2012	2013
HO1 5-Year Bond Rate (%)	-0.9	-1.92	-1.42	-0.92	-0.72
HO1 10-Year Bond Rate (%)	-0.3	-1.49	-0.99	-0.49	-0.29
HO1 30-Year Bond Rate (%)	0.09	-1.16	-0.66	-0.16	0.04
90-Day Banker's Acceptance Rate (%)	-3.68	-3.66	-2.63	-1.62	-0.44
Interest Capitalized Tx (%)	1.34	0.89	1.09	1.39	1.49
Interest Capitalized Dx (%)	1.34	0.89	1.09	1.39	1.49
Interest Capitalized Common (%)	1.34	0.89	1.09	1.39	1.49

LABOUR RATES

	2009	2010	2011	2012	2013
Society – Annual increase %	0.0	0.0	0.0	0.0	0.0
PWU – Annual increase %	0.0	0.0	0.0	0.0	0.0
MCP – Annual increase %	0.0	-1.0	-4.0	-4.0	-1.0
Incentive Plan Payouts %	0.0	0.0	0.0	0.0	0.0

BENEFIT COSTS RATES (PAYROLL BURDEN)

Company	Category	2009	2010	2011	2012	2013
Networks	Non-Regular Staff % of total earnings*	0.77%	0.67%	0.67%	0.75%	0.88%
	Regular Staff % of total earnings* % of base pensionable earnings**	0.77% -4.45%	0.67% -3.89%	0.67% -3.63%	0.75% -3.39%	0.88% -3.01%
	Pension % of base pensionable earnings	0.11%	-0.01%	-0.16%	-0.28%	-0.33%

*CPP, Emp, Insurance, Emp. Health Tax, Workers' Compensation Schedule 1 Premiums
**Health, Dental, Life Insurance, Maternity, Retirement Bonus, Post-Retirement Health, dental, Life Insurance, OPRB (for Inergi where applicable), Ontario Health Premiums (OHP)

- Base Pensionable Earnings includes pensionable bonus.
- Total Earnings includes base pay, bonus, overtime, taxable benefits and taxable allowances.
- Payroll burden rates exclude Powerflex benefits for MCP employees

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #3 List 1

Interrogatory

Issue 1.2: Are Hydro One's economic and business planning assumptions for 2011/2012 appropriate?

References: i) Exhibit A/Tab 14/Schedule 2, pages 1-6)
ii) Exhibit A-12-3 Appendix 5

a) Given the volatility in economic conditions worldwide, does Hydro One Networks consider it reasonable to rely on a Global Insight Forecast that is almost 2 years old? If yes, please explain why.
b) Is Hydro One Networks aware of any more recent projections of inflation and cost escalation for 2011 and 2012? If yes, please provide these.
c) Provide an update of the interest rate forecast for 2011 and 2012 based on the latest edition of Consensus Forecasts.
d) Update the exchange rate forecast based on the latest edition of Consensus Forecasts.
e) What is the sensitivity of Hydro One Networks' proposed 2011 and 2012 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 10 cent change in the forecast exchange rate (CDN$ per US$)?
f) What labour escalation assumptions were used for the 2010 bridge year?

Response

a) Please see Exhibit I, Tab 1, Schedule 2. Updated information is provided in Exhibit I, Tab 6, Schedule 4.

b) Please see Exhibit I, Tab 1, Schedule 1.

c) Please see Exhibit I, Tab 6, Schedule 4.

d) Please see Exhibit I, Tab 1, Schedule 1.

e) i) If test year forecasted interest rates were lower by 100 basis points, revenue requirement would be lower by $5.1M in 2011 and $12.8M in 2012.

ii) As discussed on lines 17 to 19 of page 3 of Exhibit A, Tab 12 Schedule 2, the exchange rate forecast is not directly used to forecast costs or other variables, it is an important variable affecting the performance of the Canadian and Ontario economies.

f) Please refer to Appendix A Exhibit A, Tab 12, Schedule 1, page 2 & 3 which provides the labour rate escalations assumptions for 2010 bridge year.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #4 List 1

Interrogatory

Issue 1.2: **Are Hydro One's economic and business planning assumptions for 2011/2012 appropriate?**

References: Exhibit A/Tab 12/Schedule 1, page 2

a) Please provide copies of the Business Plan instructions issued Q1-2009 and the Business Plan approved in June 2009.

Response

A copy of the Business Plan instructions issued Q1-2009 is filed in confidence with the Board and will be made available to intervenors that sign a Declaration and Undertaking form in accordance with the OEB Practice Direction on Confidential Filing.

Please refer to Exhibit I, Tab 3, Schedule 1 for the 2nd part of the question.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #5 List 1

Interrogatory

Issue 1.2: Are Hydro One's economic and business planning assumptions for 2011/2012 appropriate?

Reference: i) Exhibit A/Tab 12/Schedule 1, App A, page 1 and Schedule 2, pages 1-3; ii) Exhibit A/Tab 12/Schedule 3, page 2 and Appendix 5

a) Explain why the forecasts for CPI and Exchange rates (Reference (i)) were based on 3rd party forecasts prepare in November/December 2008 where as the forecast of economic indicators (GDP and Housing Starts) used in the Load Forecast were prepared in mid to late 2009 (Reference (ii) – Appendix 5).

b) Exhibit A/Tab 12/Schedule 3, page 2 states that the economic assumptions used in the business planning process are consistent with those used for the load forecast. Reconcile this with the discrepancy in sources noted in part (a).

c) What is the source and date of issue for the Provincial Population, Provincial Housing, Commercial Floor Space and Industrial Production forecasts presented in Reference (ii)?

d) Compare the economic assumptions for 2010-2012 (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) See Exhibit I, Tab 1, Schedule 2 and Exhibit I, Tab 1, Schedule 1 for the updated information for CPI and exchange rates. For GDP and housing starts forecast referenced in Appendix 5, the most recent information available at the time was used in preparing the forecast. Updated GDP and housing starts forecast is provided in Exhibit I, Tab 1, Schedule 21.

b) Due to timing as explained in (a) above, different versions were used. However, economic assumptions have consistently been in the same range during the forecast period (for example, CPI around 2%, exchange rate around par, GDP and housing starts have the same growth between forecast periods as compared in Exhibit I, Tab 1, Schedule 21)

c) The source and date of issue for forecasts are provided below.
- Provincial population: IHS Global Insight, June 2009
- Provincial Housing: Consensus forecast, September 2009
- Commercial Floor Space: IHS Global Insight, January 2009
- Industrial production: IHS Global Insight: July 2009

d) The forecast data used in May 2010 forecast and corresponding most recent projections are presented below.

	2010	**2011**	**2012**
Assumptions used in May 2010 Forecast			
CPI	1.9%	2.1%	2.0%
GDP	3.4%	3.1%	3.2%
Industrial Output	5.2%	6.3%	4.2%
Floor Space	1.0%	1.2%	1.3%

Most Recent Projection			
CPI (July 2010)	2.4%	2.1%	2.1%
GDP (August 2010)	3.9%	2.8%	2.9%
Industrial Output	(no new projection)		
Floor Spaces	(no new projection)		

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #6 List 1

Interrogatory

Issue 1.2: Are Hydro One's economic and business planning assumptions for 2011/2012 appropriate?

Reference: Exhibit A/Tab 9/Schedule 1 Annual Report 2008 Financial Statements page 83 Five-Year Summary of Financial and Operating Statistics

a) Provide an update/projection of overall financial statistics and transmission data for 2009 and proforma 2010-2012. Reconcile with Exhibit A/Tab 8/Schedule 2/Page 1.

Response

a) Please refer to Exhibit A, Tab 9, Schedule 1, the 2009 Annual Report, for 2009 information. Please refer to Exhibit A, Tab 8, Schedule 2 for the Proforma Statement of Income for 2010 to 2012.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #7 List 1

Interrogatory

Issue 1.2: Are Hydro One's economic and business planning assumptions for 2011/2012 appropriate?

Reference: Exhibit A/Tab 9/Schedule 2/Page 1

a) Provide a copy of the 2010 Q2 proforma.

Response

a) Provided below is the requested copy of the 2010 Q2 ProForma.

Pro Forma Statement of Income
Bridge Year (2010)
Period Ending June 30, 2010
($ Millions)

Line No.	Particulars	2010 (Q2) (a)
	Revenues	
1	Retail power & energy	616
2	Commodity flow-through	-
3	LV	-
4	Other	10
5		626
	Costs	
6	OM&A	210
7	Cost of power	-
8	Depreciation	130
9	Capital tax	3
10		343
11	Earnings before interest and income tax	283
12	Interest expense	98
13	Earnings before income tax	186
14	Income tax	20
15	Net income	166

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #8 List 1

Interrogatory

Issue 1.2: Are Hydro One's economic and business planning assumptions for 2011/2012 appropriate?

References: i) Exhibit A/Tab 13/Schedule 1:
ii)EB-2008-0272 VECC IRR #2

a) Provide/update the 2003-2009 results for each of the performance measures summarized in the following table.

Performance Measure	2003	2004	2005	2006	2007	Comments
# of LTI per 200,000 hours worked	0.29	0.40	0.50	0.50	0.40	
Customer Satisfaction (%)	61	76	81	81	86	
Smart Meters Installed (units)	n/a	n/a	n/a	n/a	222,831	Installation of Smart Meters commenced 2007
Tx Frequency of Customer Unplanned Interruptions (Ave # Interruptions per Delivery Point)*	0.20	.027	0.24	0.29	.021	
Tx Duration of Customer Unplanned Interruptions (Ave # Minutes of Interruptions per Delivery Point)*	9.6	12.5	15.9	18.9	5.1	
Major Projects (on time, on budget)	n/a	n/a	n/a	n/a	On Time/On Budget	
Dx Duration of Customer Interruptions (Hrs)	n/a	6.4	7.7	6.7	8.2	
Environmental Index	n/a	n/a	n/a	n/a	n/a	New in 2008
Skills and Safety Training	n/a	n/a	n/a	n/a	93%	
Management Development	n/a	n/a	n/a	n/a	n/a	New in 2008
Net Income After Tax (M$)	396	498	483	455	399	
Credit Rating	A -	A	A	A	A	Provided in Exhibition A-15-1, page 15
Productivity Index	n/a	n/a	n/a	n/a	n/a	New in 2008

Notes: n/a = not applicable or not explicitly tracked at corporate level

* Tx Reliability for multi- circuit supplied delivery points

Response

Performance Measure	2003	2004	2005	2006	2007	2008	2009	Comments
# of LTI per 200,000 hours worked	0.29	0.40	0.50	0.50	0.40	0.30	0.30	
Customer Satisfaction (%)	61	76	81	81	86	86	83	
Smart Meters Installed (units)	n/a	n/a	n/a	n/a	222,831	456,019	n/a	Installation of Smart Meters commenced 2007,
Fully-Enabled Smart Meters	n/a	n/a	n/a	n/a	n/a	n/a	746,865	New in 2009
Tx Frequency of Customer Unplanned Interruptions (Ave # Interruptions per Delivery Point)*	0.20	0.27Φ	0.24	0.29	0.21Φ	0.22	0.28	
Tx Duration of Customer Unplanned Interruptions (Ave # Minutes of Interruptions per Delivery Point)*	9.6	12.5	15.9	18.9	5.1	7.2	19.7	
Major Project (on time, on budget)	n/a	n/a	n/a	n/a	On Time/On Budget	On Time/On Budget	n/a	
Dx Duration of Customer Interruptions (Hrs)	n/a	6.3Φ	7.6Φ	7.0Φ	8.2	8.1	7.0	New in 2009
Environmental Index	n/a	n/a	n/a	n/a	n/a	95%	n/a	New in 2008
Oil Spills† %	n/a	n/a	n/a	n/a	n/a	n/a	97%	New in 2009
Greenhouse Gas†† tonnes	n/a	n/a	n/a	n/a	n/a	n/a	525	New in 2009
Skills and Safety Training	n/a	n/a	n/a	n/a	93%	95%	96%	
Management Development	n/a	n/a	n/a	n/a	n/a	98%	n/a	
Net Income After Tax (M$)	**396**	**498**	**483**	**455**	**399**	**498**	**470**	
Credit Rating	A-	A	A	A	A	A	A	Provided in Exhibition A-15-1,page 15
Productivity Index (% productive)	n/a	n/a	n/a	n/a	n/a	108	n/a	Used in 2008 only
Productivity - Tx Unit Costs (Capital and O&M per asset) %	n/a	n/a	n/a	n/a	n/a	n/a	10.1	New in 2009
Productivity – Dx Unit Costs (Capital and O&M per km of line) $'000s	n/a	n/a	n/a	n/a	n/a	n/a	6.2	New in 2009

Notes: n/a = not applicable/available or not explicitly tracked at corporate level

* Tx Reliability for multi-circuit supplied delivery points

†(% recovered from oil-filled electrical equipment spills)
††(# Metric Tonnes of Greenhouse Gas Removed)
Φ Correction to original evidence

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #9 List 1

Interrogatory

Issue 1.3: Is the overall increase in 2011 and 2012 revenue requirement reasonable?

Reference: Exhibit A/Tab 2/Schedule 1

a) Provide a schedule that shows the proposed bill impacts for 2011 and 2012.
b) Provide a schedule that shows the impact on a typical residential LDC customer consuming 500 and 1000 kWh/month.

Response

a) The proposed bill impacts if the application is approved as filed are 1.2% in 2011 and 0.7% in 2012, the calculation of which is detailed in the response to OEB interrogatory at Exhibit I, Tab 1, Schedule 18.
b) The impact on a typical residential 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 May 2010:		
Tx Network = 0.585 (¢/kWh		per Distribution Rate Order in EB-2009-0096 issued April 16, 2010
Tx Line & Transformation = 0.464 ¢/kWh		per Distribution Rate Order in EB-2009-0096 issued April 16, 2010
2011 Transmission Rates Impact = 15.7 %	(A)	per Exhibit A, Tab 2, Schedule 1
2012 Transmission Rates Impact = 9.8 %	(B)	per Exhibit A, Tab 2, Schedule 1
Hydro One Transmission Share of Uniform Transmission Charges = 0.96465	(C)	per Transmission Rate Order in EB-2008-0272 issued January 21, 2010

Calculation of Impacts:

	Calculation	Consumption Level		
		800 kWh (per Notice)	500 kWh	1000 kWh
RTSR included in 2010 R1 Customer's Bill *(Consumption x 1.085 R1 loss factor x RTSR Rates)*	D	9.11	5.69	11.38
Retail Transmission Service Charges in 2011	E = D x (1 + AxC)	$10.49	$6.55	$13.11
2011 increase in R1 Customer's Monthly Bill	(E - D)	**$1.39**	**$0.86**	**$1.72**
Retail Transmission Service Charges in 2012	F = E x (1 + BxC)	$11.49	$7.17	$14.34
2012 increase in R1 Customer's Monthly Bill	(F - E)	**$1.00**	**$0.62**	**$1.24**

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #10 List 1

Interrogatory

Issue 1.3: Is the overall increase in 2011 and 2012 revenue requirement reasonable?

Reference: Exhibit E1/Tab 1/Schedule 1/Page 3 Table 2

a) Provide a version of Table 2 that compares the test year to the historic year 2009:
   i. Add a column for 2009 Actual.
   ii. Update the Bridge year to reflect the latest forecast.
   iii. For each line provide the % change relative to 2009 for each of 2010,2011 and 2012.

b) Provide detailed explanations for the changes in lines 7-9.

Response

a)

Line no.	Description	Year 2009	Year 2010 Bridge Year	2010 percentage change to 2009	Year 2011	2011 percentage change to 2009	Year 2012	2012 percentage change to 2009
1	OM&A	418.8	426.2	1.8%	436.3	4.2%	450.0	7.4%
2	Depreciation	239.7	281.3	17.4%	302.9	26.4%	334.8	39.7%
3	Capital Taxes	19.3	6.0	-68.9%	0	-100.0%	0	-100.0%
4	Income Taxes[1]	24.7	34.0	37.7%	80.9	227.5%	70.0	183.4%
5	Cost of Capital[1]	465.2	509.8	9.6%	625.3	34.4%	692.6	48.9%
	Total Revenue Requirement	**1,167.7**	**1,257.3**	7.7%	**1,445.5**	23.8%	**1,547.4**	32.5%
6	Deduct External Revenues	-27.4	-18.0	-34.3%	-31.3	14.2%	-24.7	-9.9%
	Revenue Requirement less External Revenues	**1,140.3**	**1,239.3**	8.7%	**1,414.2**	24.0%	**1,522.7**	33.5%
7	Deduct Export Revenue Credit	-16.8	-12.0	-28.6%	-10.1	-39.9%	-10.2	-39.3%
8	Deduct Other Cost Charges	-7.3	-20.3	178.1%	-10.0	37.0%	2.6	-135.6%
9	Add Low Voltage Switch Gear	10.2	10.8	5.9%	11.8	15.7%	12.5	22.5%
	Rates Revenue Requirement	**1,126.4**	**1,217.7**	8.1%	**1,405.8**	24.8%	**1,527.5**	35.6%

[1] Hydro One Transmission does not calculate actual Revenue Requirement, the 2009 Income Taxes and 2009 Cost of Capital are taken from approved amounts and included only to be used for illustrative purposes. Please refer to Ex I, Tab 4, Sch 45 for further explanation.

The 2010 Bridge year forecast remains as filed in Exhibit E1, Tab 1, Schedule 1.

b) The increase in total rates revenue requirement is largely attributable to the impact of rate base growth reflected in the increase in return and depreciation, as well as, the increase in OM&A work program requirements, this is partially offset by lower tax rates and the cessation of capital taxes in 2011/2012.

Other Cost Charges increase from 2011 to 2012 due to the disposition of regulatory credits over 12 months in 2011 for rate mitigation purposes and recovery of regulatory debits over 24 months.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #11 List 1

Interrogatory

Issue 2.1: Is the load forecast and methodology appropriate and have the impacts of Conservation and Demand Management initiatives been suitably reflected?

References: i) Exhibit A, Tab 12, Schedule 3, page 3, pages 6-8 and page 19
ii) OEB Letter of June 22, 2010 re: EB-2010-0126, Appendix B

a) With respect to page 3, please provide the load forecast as prepared in September 2009 and indicate specifically what adjustments were made to account for i) 2009 actual load and ii) the revised annual CDM impact for 2010-2012.
b) Please provide details regarding the revised CDM impact for 2010-2012 referenced on page 3 including how it was developed, what specific revisions were made and why and, finally, the new impact forecast.
c) Reference (ii) (pages 11-13) indicates that the OPA has revised the near term (2008-2013) provincial conservation projections. Are Hydro One's projected CDM impacts consistent with the OPA's revised outlook? In responding please provide details for the OPA revised CDM projections for each year through to 2013, contrast with Hydro One's CDM impact forecast for 2008 through 2012 and explain any differences.
d) With respect to the Maximum Peak Demand Impacts show in Table 2 and the types of CDM programs discussed on page 7, please indicate what portion of the incremental and cumulative impact for each year is due to demand response programs (i.e., programs focused specifically on system peak and/or critical system hours) versus impacts due to more broader focused CDM programs.
e) Please confirm at what "point on the system" (e.g., point of generation) the following are measured:
   - The 2007 IPSP CDM Impacts
   - The OPA's revised conservation estimates
   - HON's Maximum Peak Demand Impacts
   - System Peak Demand as forecast by HON (per page 19)

   If they are not all measured at the same point on the system please explain what adjustments were made to reconcile the differences.
f) Please indicate how the Maximum Peak Demand CDM impact set out in Table 2 was translated into the impact on the 12-month average peak demand. In doing so please include an explanation as to how differences in system measurement points (per part (e)) and differences in the impact of different types of CDM programs (per part (d)) where accounted for.
g) With respect to page 8, please provide the referenced OPA reports and HON analysis demonstrating the government's peak reduction target for 2007 was met.
h) Please provide any reports by the OPA indicating the 2008 peak reduction results.

Response

a) The forecast prepared in September 2009 is presented in Table A1.

Table A1
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				
2009	22,794	22,242	21,115	18,239
2010	22,886	22,331	21,200	18,312
2011	23,129	22,568	21,425	18,506
2012	23,401	22,833	21,677	18,724
Load Impact of Embedded Generation				
2009	230	230	10	10
2010	320	320	10	10
2011	400	400	10	10
2012	480	480	10	10
Load Impact of CDM				
2009	1,274	1,216	1,154	992
2010	2,063	1,970	1,869	1,606
2011	2,353	2,246	2,131	1,832
2012	2,628	2,509	2,381	2,046
Load Forecast after Deducting Embedded Generation and CDM				
2009	21,290	20,796	19,951	17,237
2010	20,503	20,042	19,321	16,695
2011	20,376	19,922	19,284	16,664
2012	20,292	19,845	19,286	16,667

Note. All figures are weather-normal.

i) Adjustments attributed to using the 2009 actual load remain the same throughout the 2009-2012 period. The adjustment for Ontario Demand is 50 MW for all the years from 2009 to 2012.

ii) Please see the response to (b) below.

b) In May 2010 forecast, the CDM impact is phased in more linearly in comparison with September 2009 forecast. By 2012, there is no change, as presented in the table below.

Comparison of CDM Impact in May 2010 and September 2009 Forecasts
(12-Month Average Peak in MW)

		Charge Determinant		
Year	Ontario Demand (MW)	Network Connection (MW)	Line Connection (MW)	Transformation Connection (MW)
		May 2010 Impact		
2010	1,721	1,642	1,558	1,340
2011	2,138	2,041	1,937	1,665
2012	2,628	2,509	2,381	2,046
		September 2009 Impact		
2010	2,063	1,970	1,869	1,606
2011	2,353	2,246	2,131	1,832
2012	2,628	2,509	2,381	2,046
		Adjustment		
2010	-343	-327	-311	-267
2011	-215	-205	-194	-167
2012	0	0	0	0

c) The OPA has not published any detailed CDM projections for 2008-2013 since the release of the referenced document. The current official CDM target for the province is still the 2007 IPSP. Table 2 on page 7 in Exhibit A, Schedule Tab 12, Schedule 3 shows the annual CDM impacts assumed by Hydro One in this rate application compared to the CDM impacts in 2007 IPSP. The response to (b) above provides additional details.

d) Hydro One used the CDM impact assumptions provided by the OPA consistent with the 2007 IPSP submitted to the Board in August 2007. The table below shows the forecasted CDM program details assumed by the OPA.

CDM Impact by Type of Program (2008-2012)										
	Incremental Impact (MW)					Cumulative Impact (MW)				
	2008	2009	2010	2011	2012	2008	2009	2010	2011	2012
Energy Efficiency	116	151	356	263	263	116	267	623	886	1149
Fuel Switching	0	0	70	17	17	0	0	70	87	104
Customer-based Generation	20	44	84	8	8	20	64	148	156	164
Demand Management	115	174	277	40	41	115	289	566	606	647
Total Proposed Savings	251	369	787	328	329	251	620	1407	1735	2064
	% Contribution by Program					% Contribution by Program				
Energy Efficiency	46%	41%	45%	80%	80%	46%	43%	44%	51%	56%
Fuel Switching	0%	0%	9%	5%	5%	0%	0%	5%	5%	5%
Customer-based Generation	8%	12%	11%	2%	2%	8%	10%	11%	9%	8%
Demand Management	46%	47%	35%	12%	12%	46%	47%	40%	35%	31%
Total Proposed Savings	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%

Source: EB-2007-0707, Exhibit D, Tab4, Schedule 1, Attachment 4, Table 3.
Note: Incremental impact calculated based on cumulative impact. % contribution was calculated based on incremental and cumulated impact.

e) Yes, all the 4 items mentioned in this interrogatory are measured at the generation level.

f) The maximum CDM impact was translated into monthly peak using consistent data provided by the OPA consistent with the 2007 IPSP. All data points are measured at the generation level, so no further adjustments are required. The average of 12 monthly peak was then calculated and used in the forecast.

g) The referenced OPA document entitled “2007 Final Conservation Results” released by the OPA in February 2009 is provided as Attachment 2 to this response. Hydro One updated its analysis in a report entitled “Analysis of Conservation and Demand Management Results in Ontario” prepared in August 2010. This report is provided in Attachment 1 to this response.

h) A report entitled “2008 Final Conservation Results” released in January 2010 by the OPA is provided as Attachment 3 to this response.

Analysis of Conservation and Demand Management Results in Ontario

August, 2010

1.0 Overview

This report presents a detailed analysis of Conservation and Demand Management (CDM) programs using available information as of July 2010. The analysis was prepared to help assess the CDM impact on the load forecast.

The CDM impact on the load forecast can be grouped in the following way:

- CDM impact resulting from programs initiated by the Ontario Power Authority (OPA);
- CDM impact resulting from programs initiated by local distribution companies (LDCs);
- CDM impact resulting from programs initiated by other agencies, such as federal and provincial governments;
- CDM impact resulting from actions initiated by Ontario electricity consumers on their own that are above and beyond the natural conservation efforts assumed in the load forecast. These conservation actions are difficult to measure because they are not program specific and therefore the savings are not easily measureable.

The Ontario government set a summer peak reduction target of 1,350 MW for 2007 and another 1,350 MW for 2010. CDM program results reported by the OPA and the results of the study undertaken by Hydro One show that Ontario electricity consumers met the provincial government's peak reduction target for 2007. Recent analysis also shows that Ontario is well on its way to achieving the peak target of 1,350 MW in 2010.

Survey results from Hydro One and the OPA show that Ontario electricity consumers have participated in CDM programs offered by the OPA, LDCs and other government agencies and have taken various conservation actions on their own to save electricity. Future evaluation, measurement and verification (EMV) efforts by the OPA will be able to confirm the success achieved by Ontario electricity consumers. The following sections provide a summary of the program results recently reported by the OPA, CDM analysis undertaken by Hydro One, as well as details of CDM programs to be initiated by the OPA for the period up to 2014.

2.0 CDM Results Reported by OPA

This section summarizes the CDM program results reported by the OPA to date. In July 2008 Ontario's Chief Energy Conservation Officer (CECO) reported that based on "reported" results at the end of 2007 the province had met the peak demand reduction target of 1,350 MW for 2007.[1] Table 1 provides cumulative CDM Results from 2005 to 2007 as reported by the CECO for both OPA and non-OPA programs.

Table 1: Reported Cumulative CDM Results 2005 -2007

Conservation Activities	Estimated Demand Reduction 2005-2007 (megawatts)
Ontario Power Authority's portfolio of programs:	
Mass market	130
Commercial/institutional	150
Industrial (demand response)[12]	317
Customer-based generation[13]	1
LDC programs (not OPA-funded)	257
Natural gas companies	38
Non-governmental and other organizations	30
IESO demand response/dispatchable load program	273
Provincial regulations	1
Federal buildings/programs	117
Enwave deep lake water cooling	56
Energy management companies	21
Total	**1,391**

Source: Ontario Power Authority "2007 Results – Supplement conservation Results 2005 -2007", Page10

It is important to note that these CDM results do not capture the CDM savings from other conservation activities and programs such as:

- Naturally occurring conservation;
- New building codes and equipment standards;
- Communication and education programs initiated by other agencies;

[1] CECO's, "Annual Report 2007 Supplement: Conservation Results 2005-2007" (June 2008) can be found on the OPA website at: http://www.powerauthority.on.ca/Page.asp?PageID=122&ContentID=6564&SiteNodeID=139&BL_ExpandID=

- Conservation actions initiated by customers that are above and beyond natural conservation.

Total reported provincial CDM savings for 2005 to 2007 would be higher if these initiatives were taken into account.

In January 2009, the OPA released their final conservation results for 2007.[2] Despite some revisions, the results confirm that the province reached its first goal of a 1,350 MW peak demand reduction by 2007. Table 2 shows the final cumulative OPA CDM results for 2005 to 2007.

Table 2: Final Cumulative CDM Results 2005 -2007

Conservation programs	**Demand Reduction (MW)**
2006 OPA programs (reported savings)	18
2007 OPA programs	568
6 evaluated programs (verified savings)	*390*
6 non-evaluated programs (reported savings)	*178*
Non-OPA programs (2005-2007)	793
Total	**1379**

Source: Ontario Power Authority, "2007 OPA Conservation Programs- Evaluation Results", Page 4

Table 3 below gives a detailed description of where adjustments were made to the OPA's 2007 results based on verification of 6 programs.

Table 3: Comparison of Preliminary and Final OPA 2007 Program Results

	Preliminary results (MW) (CECO June 2008 report)	**Final results (MW) (Post EM&V process)**
Programs	Reported savings: 12 programs	Reported savings: 6 programs Verified savings: 6 programs
Mass market	130	87
Commercial/ institutional	150	135
Industrial/ demand response	317	344
Customer based generation	1	2
TOTAL	**598**	**568**

[2] OPA's "2007 Final Conservation Results" (February 2009) can be found on the OPA website at: http://www.powerauthority.on.ca/Page.asp?PageID=122&ContentID=6563&SiteNodeID=139&BL_ExpandID=

Source: Ontario Power Authority, "2007 OPA Conservation Programs- Evaluation Results", Page 4

In January 2010, the OPA released final conservation results for OPA-funded conservation programs implemented in 2008[3]. 2008 is the most recent year for which the OPA has released conservation results. The report states that:

"The OPA's conservation portfolio achieved 387 MW of peak-demand reduction and 386 gigawatt-hours (GWh) of annual energy savings as a result of 2008 conservation activities, indicating progress toward the next interim target of an additional 1,350 MW of peak-demand reduction by 2010."[4]

This report includes only OPA-funded program results and does not include savings from other conservation activities and programs as mentioned earlier. As a result, total provincial CDM savings for 2008 will be higher than the 387 MW reported for OPA-funded programs. A summary of CDM results reported by LDCs to the OEB between 2005 and 2008 can be found in Appendix A. The next section describes a special study undertaken by Hydro One to capture the total CDM impacts in the province, including impacts which are difficult to measure.

3.0 Special Study Undertaken by Hydro One

This section summarizes the results of a special study undertaken by Hydro One to measure the load impact of CDM programs in Ontario. An econometric analysis was used to measure the impact of CDM programs on summer peak for 2004 and 2009 using the hourly load profile analysis approach. This is the same approach used by Hydro One in the 2009-2010 Transmission rate application (EB-2008-0272, Exhibit A, Tab 14, Schedule 3, Attachment C).

Two separate approaches were used. The first analysis looks at all transmission connected customers including LDCs and direct customers (large industrial customers with > 5 MW of load). The second analysis removes the impact of direct customers. This second analysis is considered to be a more conservative approach to calculating CDM

[3] OPA's "2008 Final Conservation Results" (January 2010) can be found on the OPA website at: http://www.powerauthority.on.ca/Page.asp?PageID=122&ContentID=7145&SiteNodeID=139&BL_ExpandID=

results because it eliminates the impact of the 2008-2009 recession on large industrial customers.

The objective of these analyses is to measure the load impact of all CDM activities on Ontario's peak load. Hydro One chose the Load Profile Analysis Model to measure the cumulative CDM impact by 2009 as compared to 2004 base year. The detailed data assumptions, analytical methodologies and results are presented in the following sections.

Data

The main variables used in the model are weather, day type, and economic factor (monthly GDP). The "before and after CDM" load profile are weather normalized hourly load shapes. The difference between these two load shapes is the CDM impact. The following historical data were used as inputs into the models:

- Hourly load data for Ontario from 2004 to 2009
- Actual hourly weather data (temperature) for 2004-2009
- Normalized monthly and hourly weather data (temperature) for 2004-2009
- Monthly GDP for 2004-2009

Methodology

The econometric analysis includes the following steps:

Step 1: Linear regression analysis was used to model the hourly loads[5]. The functional form of the load shape for each hour i (i=1, 2,….24) is:

$$\textit{Actual Load hour } i = f\{CDD, HDD, \textit{Day Type}, GDP\}$$

Step 2: "Weather and economic impact adjustments" were computed using the coefficients derived from the above regression analysis.

Step 3: "Normalized" hourly loads from 2004 to 2009 were then generated using the above "adjustments" to remove the abnormal weather and economic impacts.

Step 4: Annual normalized energy was calculated using the normalized hourly load profile for 2004 to 2009. Load factor was applied to calculate the normalized summer peak for

[4] Ontario Power Authority, "2008 Final Conservation Results", Page 1.
[5] The first approach uses the hourly load for all transmission connected customers while the second approach excludes the loads for direct customers.

2004 to 2009. The difference between the normalized summer peak for the year 2004 to 2009 is the impact of CDM.

Results

Analysis of CDM Peak Demand Impact - Including Direct Customers

Table 4 presents the cumulative CDM impact (MW) for 2005 to 2009. These results include all transmission connected customers including LDCs and direct customers.

Table 4: Cumulative CDM Impact for 2005-2009

For All Hydro One Customers

Year	Peak Saving (MW)
2005	724
2006	1,675
2007	2,324
2008	2,553
2009	3,322

Analysis of CDM Peak Demand Impact - Excluding Direct Customers

Table 5 presents the cumulative CDM impact (MW) for 2005 to 2009. These results include all transmission connected customers *except* direct customers and represent a more conservative estimation of CDM results.

Table 5: Cumulative CDM Impact for 2005-2009

Excluding Direct Customers

Year	Peak Saving (MW)
2005	533
2006	1,217
2007	1,722
2008	1,791
2009	1,978

Conclusion of Hydro One Analysis

The econometric analysis shows that the province achieved between 1,978 MW and 3,322 MW of peak reduction between 2004 and 2009. The analysis is consistent with results from the OPA which indicate that Ontario has successfully achieved the target peak demand reduction of 1,350 megawatts by 2007. This analysis suggests that the province is well on its way to achieving the second target of another 1,350 megawatts by 2010.

4.0 CONSERVATION ACTIONS INITIATED BY CUSTOMERS

CDM programs initiated by the OPA, LDCs, and other federal and provincial governments are mostly program-specific and as such the program results are tracked and measured. Conservation actions initiated by customers on their own contribute to CDM savings but are difficult to measure because there are no specific evaluations to capture these impacts. For example, it is very difficult to measure the "cultural change" associated with the CDM education and communication materials circulated by LDCs and other agencies (see Appendix B for details).

Hydro One Distribution undertook CDM surveys in 2007 and 2009 to confirm what conservation actions its retail customers have undertaken since 2004. Detailed analysis of the survey results can be found in Appendix C. Based on the survey results, it is clear that Ontario electricity consumers have responded to the conservation challenge, have participated in CDM programs offered by the OPA, LDCs and other government agencies and have taken various conservation actions on their own to save electricity. Hydro One's survey results are consistent with the survey undertaken by the OPA in 2008 (see Appendix D for details).

5.0 FUTURE CDM PROGRAMS

For future CDM programs, Hydro One Networks uses the CDM impacts provided by the OPA consistent with the IPSP submitted to the Board in August 2007. Table 6 summarizes the CDM programs by type of initiative. Further details by region, end-use profile and program are provided in Appendix E.

Table 6: Identified Saving Potential on System Peak (MW) and Energy Saving Potential (TWh)

	System Peak Savings (MW)					Energy Savings (TWh)				
	2010	2011	2012	2013	2014	2010	2011	2012	2013	2014

Energy Efficiency	623	886	1149	1412	1675	3.5	4.8	6.2	7.5	8.8
Fuel Switching	70	87	104	121	139	2.4	2.9	3.4	3.8	4.3
Customer-based Generation	148	156	164	172	180	0.9	1	1	1.1	1.1
Conservation Behaviour	0	0	0	0	0	0	0	0	0	0
Demand Management	566	606	647	687	728	0.1	0.1	0.1	0.1	0.1
Total Proposed Savings	1407	1735	2064	2393	2721	6.9	8.8	10.7	12.4	14.3

Source: Ontario Power Authority IPSP Pre-filed evidence in EB-2007-0707, Exhibit D, Tab4, Schedule 1, Attachment 4, Table 3 and Table 4

Table 7 presents the forecasted savings for province-wide programs under Tier 1 Conservation Programs. Savings from LDC Tier 2 and 3 programs and from Smart Meters will be in addition to the forecasted savings shown in the table.[6]

Table 7: Forecasted Savings on System Peak (MW) by Sector (Tier 1 Only)

2014 Summer Peak Demand Savings (MW)

Program	Resource Type		
	Energy Efficiency	Demand Response	Total
Consumer Program	127	192	**319**
Low Income	6	0	**6**
Business Program	418	80	**498**
Industrial Program	71	143	**214**
Portfolio Total	**622**	**416**	**1,037**

Source: OPA LDC Web-enabled teleconference, “Tier 1 Conservation Programs Webinar Series”, July 2010.

[6] OPA LDC Web-enabled teleconference, “Tier 1 Conservation Programs Webinar Series”, July 2010, http://sn.na4.acrobat.com/p59683322/

Appendix A: CDM Results Initiated by Local Distribution Companies

This appendix summarizes the CDM results reported to the OEB by LDCs between 2005 and 2008. Table A1 provides a "bottom up" view of the CDM impact for each LDC between 2005 and 2008 as reported on the OEB website.

Table A1:

Cumulative LDC CDM Program Results 2005-2008

LDC	Cumulative Peak Saved (kW)	Cumulative Energy Saved (kWh)
Barrie Hydro Distribution Inc.	557	4,616,820
Bluewater Power Distribution Corporation	53	240,876
Brant County Power Inc.	355	1,846,935
Brantford Power Inc.	160	1,158,760
Burlington Hydro Inc.	235	3,155,386
Cambridge and North Dumfries Hydro Inc.	2,149	8,469,478
Centre Wellington Hydro Ltd.	165	838,693
Chatham-Kent Hydro Inc.	353	420,823
Clinton Power Corporation	0	741,852
COLLUS Power Corporation	503	1,968,869
Cooperative Hydro Embrun Inc.	2,850	329,115
E.L.K. Energy Inc.	0	737,837
Enersource Hydro Mississauga Inc.	13,451	57,543,882
ENWIN Utilities Ltd.	3,995	31,845,969
Erie Thames Powerlines Corporation	43	1,039,417
Essex Powerlines Corporation	3,206	5,833,075
Festival Hydro Inc.	245	3,819,208
Grand Valley Energy Inc.	61	289,326
Grimsby Power Incorporated	161	1,600,156
Guelph Hydro Electric Systems Inc.	1,740	11,328,554
Haldimand County Hydro Inc.	172	877,699
Halton Hills Hydro Inc.	110	52,668
Horizon Utilities Corporation	4,626	40,465,778
Hydro 2000 Inc.	192	221,773
Hydro Hawkesbury Inc.	0	152,062
Hydro One Brampton Networks Inc.	985	43,422,480
Hydro One Networks	67,429	284,575,293
Hydro Ottawa Ltd.	7,167	77,922,277
Innisifil Hydro Distribution Systems Limited	12	106,409
Kenora Hydro Electric Corporation Ltd.	84	302,583
Kingston Hydro Corporation	91	475,824
Kitchener-Wilmot Hydro Inc.	2,878	30,422,994
Lakefront Utilities Inc.	390	1,953,139
Lakeland Power Distribution Limited	331	1,962,497
London Hydro Inc.	8,726	109,531,929
Middlesex Power Distribution Corporation	113	292,301
Midland Power Utility Corporation	220	1,699,367
Milton Hydro Distribution Inc.	661	1,185,995
Newmarket-Tay Power Distribution Ltd. - Main	159	34,248

LDC	Cumulative Peak Saved (kW)	Cumulative Energy Saved (kWh)
Niagara-on-the-Lake Hydro Inc.	180	610,161
Norfolk Power Distribution Inc.	446	2,013,376
North Bay Hydro Distribution Limited	2	11,513,832
Oakville Hydro Electricity Distribution Inc.	153	11,199,029
Orangeville Hydro Limited	40	683,276
Orillia Power Distribution Corporation	770	1,318,696
Oshawa PUC Networks Inc.	1,245	3,134,923
Ottawa River Power Corporation	61	1,809,485
Parry Sound Power Corporation	67	1,025,807
Peterborough Distribution Incorporated	3,342	10,001,523
PowerStream Inc.	11,872	32,855,417
PUC Distribution Inc.	75	3,520,740
Renfrew Hydro Inc.	40	258,311
Rideau St. Lawrence Distribution Inc.	153	686,807
St. Thomas Energy Inc.	169	577,601
Thunder Bay Hydro Electricity Distribution Inc.	1,417	6,693,525
Toronto Hydro -Electric System Limited	68,520	262,371,278
Veridian Connections Inc.	1,147	18,618,718
Wasaga Distribution Inc.	346	1,042,365
Waterloo North Hydro Inc.	546	6,510,457
Welland Hydro-Electric System Corp.	232	2,856,861
Wellington North Power Inc.	38	536,569
West Coast Huron Energy Inc.	60	128,966
West Perth Power Inc.	0	28,560
Westario Power Inc.	497	4,409,981
Whitby Hydro Electric Corporation	1,359	9,061,028
Woodstock Hydro Services Inc.	456	3,138,979

Source: OEB website for CDM results by LDCs

Appendix B: CDM Education and Communication Programs

This appendix describes the CDM education and communication programs and activities offered by Hydro One Distribution, the OPA, and other government agencies.

Hydro One Distribution

In the past few years, Hydro One Distribution has used bill inserts, newspapers, special events, conferences and workshops, radio and TV series, fact sheets, energy efficiency guides, brochures, on-line energy audits and direct mail to promote energy efficiency and conservation. The availability of this information will help our customers build the "conservation culture". Please visit www.PowerSaver.ca for more information.

Table B1 shows all energy conservation related bill inserts sent out to customers in 2005 by Hydro One.

Table B1: Distribution of Bill Inserts and Energy Saving Tips in 2005

Topic	Printed and distributed pieces (000s)
Home Energy Efficiency Grant	22
Switch to Cold – 1	1,215
Switch to Cold – 2	1,215
Lighten Your Electricity Bill	1,215
Total	**3,667**

Source: Hydro One Communications Department

Compared to 2005, Hydro One in 2006 distributed 18% more inserts and energy saving tips with customer's monthly bills. Table B2 below lists all the energy saving or conservation related inserts sent to customers.

Table B2: Distribution of Bill Inserts and Energy Saving Tips in 2006

Topic	Printed and distributed pieces (000s)
Staying Connected - Winter '05	1,215
Staying Connected - Spring '06	1,215
Staying Connected - Summer '06	1,215
Power Cost Monitors	140
Power Cost Monitors v2	140
Cold Shoulder Fridge Retirement	350

SmartStat P. Thermostats	25
Don't be a Fridge Magnet	22
LED Traffic Lights	1
LED Traffic Lights	1
LED Light Exchange	1
Total	**4,325**

Source: Hydro One Communications Department

In 2007, the number of energy saving bill inserts more than doubled in comparison to 2006. Table B3 provides details of inserts sent to customers in 2007.

Table B3: Distribution of Bill Inserts and Energy Saving Tips in 2007

Topic	**Printed and distributed pieces (000s)**
Staying Connected - Winter 06-07	1,215
Staying Connected - Summer '07	1,215
Staying Connected - Fall '07	1,215
Smartstat thermostat, Zones 1&2	150
Online Appliance Survey	100
Cold Shoulder Fridge Retirement	1,500
10/10 Summer Savings program	950
Peaksaver thermostat program	1,215
OPA Great Refrigerator Roundup	1,500
PowerSaverPlus for Residential & Business Customers	1,500
Electricity Retrofit Incentive Program – ERIP	15
ERIP	15
ERIP promotional card on heavy stock	11
Total	**10,609**

Source: Hydro One Communications Department

Table B4 presents all energy conservation related bill inserts sent out to customers in 2008 by Hydro One.

Table B4: Distribution of Bill Inserts and Energy Saving Tips in 2008

Topic	**Printed and distributed pieces (000s)**
Staying Connected - Spring '08	1,215
Staying Connected - Fall '08	1,215
Summer Sweepstakes cover letter	80
Summer Sweepstakes program	1,001
OPA Great Refrigerator Roundup	1,650

PowerSaverPlus for Residential & Business Customers	1,650
PeakSaver program	1,100
Electricity Retrofit Incentive Program - ERIP	93
PowerSavings Blitz	15
Double Return	2
Conserving Energy Together	5
Total	**8,026**

Source: Hydro One Communications Department

Table B5 presents all energy conservation related bill inserts sent out to customers in 2009 by Hydro One.

Table B5: Distribution of Bill Inserts and Energy Saving Tips in 2009

Topic	**Printed and distributed pieces (000s)**
Staying Connected - Spring '09	1,215
Staying Connected - Fall '09	1,215
Great Refrigerator Roundup	2,744
Double return for Business Customers	2
PowerSaverPlus for Residential & Business Customers	1,650
Power Savings Blitz for Business Customers	95
Electricity Retrofit Incentive Program – ERIP	21
Peaksaver Program	390
Smart Meter	480
Total	**7,812**

Source: Hydro One Communications Department

Ontario Power Authority

The OPA also undertakes several initiatives to educate consumers about conservation and to support the effectiveness of its conservation programs. In 2008, these initiatives included:

- Conservation awareness activities such as Energy Conservation Week, Conservation Awareness Day at Rogers Centre, Media Events and Greeting Card Contests;
- Market research;
- Education and training activities;
- The Conservation Fund and Technology Development Fund.

Results of a June 2008 Ipsos Reid poll indicated that 73% of Ontario residents were aware of Energy Conservation Week and 50% participated in an energy conservation activity during the week.[7]

More information on OPA initiatives can be found on their website at:

- OPA - http://www.powerauthority.on.ca

Other Sources

In addition to Hydro One Distribution and OPA CDM education and communication program and activities, similar CDM materials and communication programs are offered by other government agencies. They can be found on the following websites:

- Office of Energy Efficiency - http://oee.nrcan.gc.ca
- Ministry of Energy - http://www.energy.gov.on.ca
- Powerwise - http://www.powerwise.ca

[7] See Ontario Power Authority, "2008 Final Conservation Results", Page 11.

Appendix C: CDM Surveys Undertaken by Hydro One

This appendix summarizes the key results of two surveys initiated by Hydro One Distribution. The main objective of the surveys was to assess the conservation actions, if any, undertaken by Hydro One Retail customers since 2004, particularly customer conservation actions that could not be easily captured by CDM programs initiated by Hydro One Distribution, OPA or other federal and provincial government agencies. The survey results clearly demonstrated that Ontario residential customers are taking energy-efficiency actions on their own.

The first survey was initiated between December 2007 and January 2008 and over 1,740 customers responded (39.2% response rate). The second survey was in 2009 and 2,829 customers responded (29.9% response rate). Both surveys clearly demonstrated that Ontario residential customers have continued to participate in the conservation challenge and have taken various conservation actions on their own to save electricity.

Conservation Culture

The 2009 survey results are consistent with the 2007 survey results with respect to conservation culture. Both survey results show that Hydro One Distribution retail customers are increasingly taking conservation actions on their own, such as turning off lights when not required, using natural cooling (i.e. not using air conditioning), setting thermostat lower during the day, the night and when away, and using cold water for laundry.

These conservation actions save energy, but they are not easily measureable and the saving impacts are not properly captured.

Conservation Action	2003	2004	2005	2006	2007	2008*	2009*
Use a programmable thermostat	38%	42%	47%	53%	57%	63%	69%
Set thermostat lower during the day and when away	65%	71%	75%	80%	82%	93%	93%
Set thermostat lower during the night	63%	69%	72%	77%	80%	91%	91%

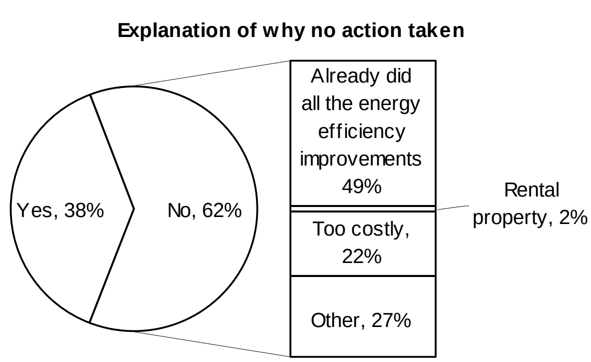
Turn off air conditioner when not at home	39%	43%	48%	53%	56%	63%	70%
Natural cooling	68%	73%	77%	82%	85%	95%	95%
Regular maintenance of air conditioning	55%	59%	63%	67%	69%	63%	71%
Switch to non-electric space heating equipment	22%	25%	27%	29%	30%	38%	41%
Insulate electric water heater and pipes	34%	37%	40%	43%	46%	47%	52%
Use cold water doing laundry	49%	54%	62%	70%	75%	80%	91%
Switch to non-electric water heating equipment	22%	24%	25%	25%	26%	38%	41%
Turn off lights when not required	85%	90%	91%	95%	96%	96%	96%
Use timer for indoor lights	25%	27%	29%	30%	31%	37%	41%
Use timer for outdoor lights	36%	39%	43%	45%	48%	48%	53%
Use a dimmer switch	45%	48%	51%	53%	55%	64%	69%
Use motion sensor	36%	39%	43%	45%	46%	50%	55%
Switch to LED holiday lights	8%	12%	23%	45%	56%	70%	78%
Switch to other LED lights	4%	3%	6%	11%	14%	35%	41%
Use timer on pool pump or heater	7%	8%	9%	10%	11%	11%	12%
Use insulating or solar blanket to keep the pool water warm	11%	12%	13%	14%	15%	13%	14%
Switch to non-electric pool heating	-	-	-	-	-	4%	5%
Hang clothes to dry	54%	57%	61%	63%	65%	74%	83%
Wash dishes by hand	46%	48%	51%	53%	55%	56%	63%
Air sealing and weatherization	37%	41%	47%	52%	54%	64%	71%
Control other equipment with timers	11%	11%	12%	13%	15%	24%	27%

Note: *2008 and 2009 data are based on results from the 2009 CDM survey; the rest are based on results from the 2007 CDM survey.

Participation in Conservation programs in 2008 or 2009

- In Question 1 of the 2009 survey, 38% of the survey respondents said they participated in CDM programs in 2008 or 2009.
- For those who did not participate in any CDM programs in the 2008 or 2009, about half of the respondents said they had already done all the energy efficiency improvements already.

Have you participated in any CDM programs in 2008 or 2009?	Percentage
Yes	38%
No	62%



- Survey results show about 25% of Hydro One customers plan to undertake conservation actions in the next two years (2010 and 2011).

Type of Conservation Action	Customers answered "No" in Question 1		Customers answered "Yes" in Question 1	
	Percent of customers who plan to do CDM	**How much $ they plan to spend per home**	**Percent of customers who plan to do CDM**	**How much $ they plan to spend per home**
Increased Home Insulation	23.4%	$1,970	26.6%	$1,881
Upgraded Windows / Skylights / Doors	29.2%	$3,453	32.2%	$3,862
Upgraded Heating System	14.7%	$7,103	12.5%	$5,059
Installed ENERGY STAR® Central AC	7.0%	$2,950	7.2%	$3,224
Installed ENERGY STAR® Window AC	3.6%	$343	1.5%	$342
Installed Energy Efficient Light Bulbs	57.7%	$93	53.2%	$73
Purchased ENERGY STAR® Appliances	28.1%	$1,940	27.6%	$1,459
Installed Programmable Thermostat	18.0%	$111	11.4%	$119
Others	15.5%	$5,028	15.3%	$4,447

Spill-over effects

Survey results show a significant number of customers who undertook CDM actions without receiving incentives. This finding confirms that Hydro One Distribution retail customers are taking CDM actions on their own and these actions are not yet captured in CDM program results reported by Hydro One Distribution, the OPA or other programs initiated by the federal and provincial governments.

Conservation Actions	Number of customers in total	Number of customers who received incentives	Ratio for customers who did not receive incentives versus customers who received incentives
Increased Home Insulation	156	25	5.24
Upgraded Windows / Skylights / Doors	249	29	7.59
Upgraded Heating System	164	73	1.25
Installed ENERGY STAR® Central AC	49	20	1.45
Installed ENERGY STAR® Window AC	36	3	11.00
Installed Energy Efficient Light Bulbs	616	133	3.63
Purchased ENERGY STAR® Appliances	356	80	3.45
Installed Programmable Thermostat	200	64	2.13
Others	88	26	2.38

Appendix D: CDM Survey Results Reported by the OPA

The OPA survey results show that the conservation efforts are similar to Hydro One distribution customers, indicating across Ontario most consumers are already conserving electricity at home and are adopting new conservation actions as time goes by. Table D1 compares the OPA and Hydro One CDM survey results.

Table D1:

Conservation Actions Adopted by Ontario Electricity Consumers

Conservation Action	H1 2007 CDM Survey	H1 2009 CDM Survey	OPA 2008 CDM Survey
Set back thermostat	82%	93%	84%
Use cold water doing laundry	75%	91%	86%
Use CFLs or other energy efficient lights	81%	N/A	88%
Turn off lights when not in use	96%	96%	95%
Use a dimmer switch	55%	69%	51%
Hang clothes to dry	65%	83%	77%
Upgrade windows/door to prevent air leakage	48%	N/A	64%

Source: OPA 2008 Electricity Conservation Program Study July 2008, Slide 34

Appendix E: OPA Conservation Program Portfolio 2010-2014

Table E1: OPA Portfolio 2010-2014 by Region

	System Peak Savings (MW)					Energy Savings (TWh)				
	2010	2011	2012	2013	2014	2010	2011	2012	2013	2014
Northwest	64	76	86	96	105	0.2	0.3	0.4	0.5	0.5
West	161	196	231	265	300	0.7	0.9	1	1.2	1.4
Northeast	91	106	120	134	148	0.6	0.7	0.8	1	1.1
Essa	96	115	134	154	173	0.5	0.6	0.7	0.8	0.9
Ottawa	97	123	150	177	204	0.6	0.7	0.8	1	1.1
East	83	100	117	134	151	0.4	0.5	0.6	0.7	0.8
GTA	478	606	737	868	1000	2.5	3.2	3.8	4.5	5.1
Niagara	41	51	60	69	79	0.2	0.3	0.3	0.4	0.4
Southwest	296	363	429	495	561	1.3	1.7	2.1	2.4	2.8
Ontario	1407	1736	2064	2393	2721	6.9	8.8	10.6	12.4	14.3

Source: Ontario Power Authority IPSP Pre-filed evidence in EB-2007-0707, Exhibit D, Tab4, Schedule 1, Attachment 4, Table 5 and Table 6

Table E2: OPA Portfolio 2010 by End Use Profile

	System Peak Savings (MW) in 2010	Energy Savings (TWh) in 2010
Residential	213	1.4
Space Heating SFD	0	0.1
Space Heating AP/AT	0	-0.2
Room AC	8	0
Central AC	90	0.1
Furnace Fan	47	0.1
Lighting	35	1
Refrigeration	4	0
Freezer	3	0
Water Heating	5	0.1
Dish Washer	1	0
Clothes Waster/Dryer	4	0
Miscellaneous	16	0.2
Commercial/Institutional	302	1.3
Space Heating	0	0.1
Space Cooling	118	0.1
Ventilation	30	0.2
Lighting	146	0.9
Electric Auxiliary	5	0
Water Heating	3	0
Industrial	107	0.8
Process Machine Drive	45	0.4
Electrochemical Processes	1	0
Steam Production	0	0
Heat Production	38	0.3
HVAC	20	0.1
Lighting	3	0

Source: Ontario Power Authority IPSP Pre-filed evidence in EB-2007-0707, Exhibit D, Tab4, Schedule 1, Attachment 4, Table 9

ONTARIO POWER AUTHORITY

2007 Final Conservation Results

February 2009

Ontario Power Authority OM

Contents

Introduction

Ontario has a long-term conservation target to achieve 6,300 megawatts (MW) of peak electricity demand reduction.[1] Aggressive interim targets included a 1,350 MW peak demand reduction by 2007 and an additional 1,350 MW reduction for 2010. The OPA has a leadership role in coordinating the province's electricity conservation efforts and working in partnership with local distribution companies (LDCs) and others to ensure Ontario's conservation targets are met.

The OPA is adopting a long-term planning, market transformation approach to ensure that conservation is sustainable, reliable and cost-effective. In parallel with this long term planning, the OPA is funding conservation programs that encourage immediate conservation actions by consumers and businesses and which will help the province meet its near term targets.

The OPA procures conservation resources through conservation programs that deliver demand reduction, energy savings and conservation awareness. The primary focus for OPA programs in the near term is peak demand reductions. In 2007, the OPA procured energy and demand savings through the delivery of 12[2] programs.

The OPA is committed to being open and transparent on the progress and results of its programs. As outlined in its evaluation, measurement and verification (EM&V) framework, the OPA is also committed to undertaking rigorous independent evaluations of OPA-funded programs in accordance with internationally credible standards.

The primary purpose of program evaluations is to verify and ensure the reliability of demand reduction and energy savings achieved. This is important since it helps determine the amount of generation that must be built to meet provincial energy needs. Evaluations are also used to assess program design performance, to provide information for continuous management improvement and to validate input assumptions made for specific end-use measures. This facilitates the OPA's approach of "learning by doing."

Comprehensive evaluations were undertaken on a subset of the conservation portfolio covering six programs delivered by OPA in 2007, the results of which are summarized in this report. Going forward, every program in the OPA's 2008-2010 portfolio will undergo a full evaluation at least once during the three-year portfolio cycle, with many of the programs being reviewed annually.

The purpose of this report is two-fold. It summarizes Ontario's conservation results against the 2007 provincial target and also presents the results of the comprehensive third party evaluations that were undertaken on six of OPA's programs in 2007. A concise summary of the savings verified through the 2007 EM&V process are included in the body of the report, followed by an appendix which includes a glossary, a description of the OPA's conservation reporting methodology and more detailed summaries of each program evaluation.

[1] On September 17, 2008, the Minister of Energy and Infrastructure issued a directive asking the OPA to review the viability of accelerating the achievement of stated conservation targets.

[2] *The 2007 Progress Report on Electricity Conservation* (April 2008) indicated that the OPA had 14 programs in market in 2007. Two of these programs did not generate energy or demand savings in 2007 (the agricultural program, as it was focused on marketing; and the Demand Response 3 program, as it launched in December).

The OPA does not conduct evaluations of non-OPA funded programs. Please refer to Ontario's Chief Energy Conservation Officer's supplement to the 2007 annual report, *Conservation Results, 2005-2007*, for the full list of program results. Given the importance of the conservation contribution in ensuring the reliability of Ontario's electricity system over the next 20 years, the Chief Energy Conservation Officer is recommending and encouraging all delivery agents in the conservation marketplace to adopt more rigorous and consistent methods of measuring and verifying results.

Provincial results against 2007 target

Preliminary results

Ontario's Chief Energy Conservation Officer (CECO) reported in June 2008 that the province had met the 2007 peak demand reduction target. This conclusion was based upon available "reported"[3] results from the Independent Electricity System Operator (IESO), OPA conservation programs, provincial and federal governments, LDCs, natural gas companies, non-governmental organizations and other participants in the conservation marketplace, as shown in Table 1 below. The June 2008 CECO report did not include results of the OPA's 2006 conservation programs or the results of the OPA's third party evaluation, measurement and verification (EM&V) process on six of its own 2007 programs, as this review was still underway at the time.

Table 1 Ontario conservation reported results (June 2008)

Conservation programs	Demand Reduction (MW)
2007 OPA programs (reported savings)	598
2005-2007 Non-OPA programs (reported savings)	793
Total	**1391**

Final results

Table 2 below provides a final summary of Ontario conservation program results against the 2007 peak demand reduction target. The Chief Energy Conservation Officer's conclusion that Ontario has met its 2007 conservation target remains unchanged.

There are two key differences between the preliminary and final results: the demand savings from OPA's 2006 programs (18 MW) have been added[4]; and the OPA's 2007 program results have been adjusted downward 30 MW based on final "verified" results. In 2007, the OPA procured energy and demand savings through the delivery of 12[5] conservation programs. Comprehensive evaluations, including rigorous measurement and verification, were undertaken on six of these programs. Going forward, every conservation program in the OPA's 2008-2010 program portfolio will undergo a full evaluation at least once during the three-year portfolio cycle, with many of the programs being reviewed annually. Table 3 provides a more detailed accounting of the adjustments made to OPA's 2007 results as a result of EM&V.

[3] The OPA uses two terms -- reported savings and verified savings-- in tracking and reporting on the progress and results of conservation programs. Reported savings are estimates based on program design parameters and reported program participation levels. Verified savings, which have a higher level of certainty, are third-party determinations of savings based on review of program design parameters and confirmation of participation and implementation levels. For example, our reported savings for an energy efficient lighting coupon program would be estimated based on the number of coupons redeemed multiplied by our upfront assumption of energy savings per light bulb. The verified savings for the program, calculated after the program is completed, will be based on the actual number of light bulbs installed by participants (which may be less than the number of coupons redeemed) and the actual energy savings per bulb (which may be higher or lower than our upfront assumption depending on how people are using the bulbs).

[4] For details on 2006 program results please refer to the Ontario's Chief Energy Conservation Officer's supplement to 2006 annual report, *2006 Results*, available on the OPA website.

[5] *The 2007 Progress Report on Electricity Conservation* (April 2008) indicated that the OPA had 14 programs in market in 2007. Two of these programs did not generate energy or demand savings in 2007 (the agricultural program, as it was focused on marketing; and the Demand Response 3 program, as it launched in December).

Table 2 Ontario conservation final results

Conservation programs	**Demand Reduction (MW)**
2006 OPA programs (reported savings)	18
2007 OPA programs	568
6 evaluated programs (verified savings)	*390*
6 non-evaluated programs (reported savings)	*178*
Non-OPA programs (2005-2007)	793
Total	**1379**

Table 3 Comparison of OPA 2007 program results: reported vs verified results

	Preliminary results (MW) (CECO June 2008 report)	**Final results (MW) (Post EM&V process)**
Programs	Reported savings: 12 programs	Reported savings: 6 programs Verified savings: 6 programs
Mass market	130	87
Commercial/ institutional	150	135
Industrial/ demand response	317	344
Customer based generation	1	2
TOTAL	**598**	**568**

Evaluation of OPA programs

Results for the six evaluated programs, including verified savings, lessons learned and recommendations are discussed in subsequent chapters of this report. The results do not follow any common trend, and each conservation program has unique circumstances and evaluation results. Because of this, the OPA is not able to extrapolate results to the non-evaluated programs.

The 2007 results confirm that overall progress is substantial. Energy and demand savings are expected to continue to grow steadily as programs grow and mature in the marketplace. Observed high levels of participation show a growing awareness of the value of conservation behaviour. In addition, OPA conservation programs are contributing to ancillary benefits such as economic activity, environmental improvement and a growing culture of conservation in Ontario.

Evaluation of non-OPA programs

Ontario's results are encouraging, but it is recognized that more work is required to develop measurement and verification methodologies to better assess the impact of non-OPA funded conservation programs. While the OPA's portfolio of programs is assessed using rigorous independent evaluations in accordance with internationally credible standards, the current mix of results from the various parties is derived from program forecasts or reported results. These results are based on assumptions regarding the activities undertaken and, while they provide an indication of the success at reducing Ontarians' need for electricity, they are not as reliable as verified results based on a comprehensive, independent measurement process.

Given the importance of the conservation contribution in ensuring the reliability of Ontario's electricity system over the next 20 years, the Chief Energy Conservation Officer is recommending and encouraging all delivery agents in the conservation marketplace to adopt more rigorous and consistent methods of measuring and verifying results.

OPA program evaluations

The verified savings for the six evaluated programs are summarized in Table 4 below. Overall, the evaluation results confirm the success of the 2007 conservation program efforts. The results do not follow any common trend, and each conservation program has unique circumstances and evaluation results. Because of this, the OPA is not able to extrapolate these results to the non-evaluated programs.

Table 4 – 2007 Verified Results

Program	Activity measure	Activity units	Net summer peak demand savings (MW)	Net first-year energy eavings (GWh)	Net lifetime energy savings (GWh)
2007 Every Kilowatt Counts	Coupons	2,773,186	4.9	132	1,060
2007 Great Refrigerator Roundup Program	Appliances	49,832	1.7	13.4	117.1
2007 Hot & Cool Savings Rebate Program	Rebates	160,205	19.8	30.2	451.1
2007 Summer Savings	Households	380,000	45	81	145
2007 Toronto Comprehensive – Building Operators & Managers Association (BOMA)	Buildings	12	0.7	5.6	79.3
2007 Demand Response 1 Program	Contracts	10	317.4[6]	--	--

The mass market/residential programs were generally successful in launching on schedule and driving participation rates. There were some significant adjustments to the energy savings assumptions per conservation measure in the evaluations, which led to some programs not reaching their energy or demand savings forecasts.

The commercial and industrial programs have been comparatively slower in rolling out and driving participation rates. However, this is typical for these types of programs, as businesses generally require longer lead times to make energy-efficiency investments. The evaluations of the business market programs indicated that these programs are benefiting from solid program designs that will provide the foundation for increased participation and savings as the programs move forward.

In addition to verifying the savings or conservation resource achieved in these programs, the evaluations provided insights into the effectiveness of the program designs and delivery and made recommendations for improvement where applicable. As seen in the evaluation highlights, many of the process review findings and related recommendations were already identified by program staff and incorporated into 2008 programs prior to the completion of the evaluation process.

The 2007 results confirm that overall progress is substantial. Energy and demand savings are expected to continue to grow steadily as programs mature and new programs enter the

[6] The total amount of curtailment available through contracts signed by participants in demand response programs, also known as the nameplate capacity, was used to report progress against the 2007 demand reduction target.

marketplace. Observed high levels of participation show a growing awareness of the value of conservation behaviour. In addition, OPA conservation programs are contributing to ancillary benefits such as economic activity, environmental improvement and a growing culture of conservation in Ontario.

Conclusion

Ontario's Chief Energy Conservation Officer (CECO) reported in June 2008 that the province had met the 2007 peak demand reduction target, based on preliminary results of OPA programs. This report provides a final summary of Ontario conservation program results against the 2007 peak demand reduction target. The Chief Energy Conservation Officer's conclusion that Ontario has met its 2007 conservation target remains unchanged.

The results of the OPA program evaluations have shown that some programs have performed better than anticipated, while others have provided information for future programs – an essential part of learning – that will help ensure the OPA portfolio approach achieves best practices. Evaluation findings have already guided program staff to make improvements to programs for 2008 and beyond as part of a continuous improvement methodology. In summary, overall, the portfolio is making good progress.

A comprehensive annual report for 2008 that includes the full year's results, including program evaluations, is scheduled to be available in the third quarter of 2009.

Appendix A - Glossary

Average curtailment: the mean curtailment in a given a period of time expressed in megawatts and a percentage of contracted capacity at the time of curtailment.

Contracted capacity: the total amount of curtailment available through contracts signed by participants of a demand response program.

First-year energy savings: electricity savings achieved in the first year of implementation of a conservation program's measures.

Free-ridership: occurs when a number of customers take advantage of rebates or cost savings available through conservation programs even though they would have installed the efficient equipment on their own. Such customers are commonly referred to as "free riders." These customers may already be motivated to purchase energy-efficient equipment even without utility-sponsored incentives. The savings resulting from free riders cannot be attributed to the conservation program and, therefore, should not be counted as resource savings.

Lifetime energy savings: electricity savings achieved during the entire estimated usage life of a conservation program's measures.

Maximum curtailment: the peak curtailment in a given a period of time expressed in megawatts and a percentage of contracted capacity at the time of curtailment.

Net savings: electricity savings achieved that are directly attributable to a conservation and demand management program. Net savings are adjusted for free-ridership, rebound effect, spillover, etc.

Participation: program uptake in terms of program-specific measures (e.g., rebate coupons redeemed for the Every Kilowatt Counts program, refrigerators and freezers retired for the Great Refrigerator Roundup, buildings retrofitted for the Toronto Comprehensive – BOMA program, curtailment events for Demand Response 1).

Rebound effect: occurs when some conservation measures may result in savings during certain periods but induce increased energy use before or after the period in which the savings occur. This is particularly common for demand response programs that, for example, reduce air conditioning loads during peak hours but cause customers to leave their air conditioners on later in the evening.

Spillover: the opposite of the free-rider effect. This refers to consumers who adopt efficiency measures themselves because they are influenced by an efficiency program but do not actually participate in the program.

Summer peak demand savings: the estimated electricity savings that occurred at the time of the summer province-wide electrical system load peak.

Appendix B - Ontario Power Authority's Conservation Reporting Methodology

The Ontario Power Authority uses three different reporting "tracks" to monitor and report on its funded conservation programs -- forecasted, reported and verified savings. Each of these tracks provides estimates of energy and peak demand savings resulting from conservation programs, and each track has a different level of certainty associated with the results.

Forecasted Savings

Planning, designing and developing a conservation program involves developing predictions of the potential energy and demand reductions that could result from it. These forecasted savings are based on a set of input assumptions, including estimated participation rates, energy and demand reductions resulting from program measures, the effective useful life of measures and other factors. The forecasted savings can be used as targets for the program, against which actual performance can be measured. Forecasted savings tend to have the largest bands of uncertainty associated with them.

Reported Savings

Reported savings reflect the preliminary results of conservation programs using the same input assumptions that were used to develop the program. Program activity is tracked using units specific to the program, such as coupons redeemed, appliances retired or control devices installed. These activity units are used to estimate energy and demand savings with the same assumptions used to create the program – allowing for straight comparisons to the forecasted savings.

Reported savings reflect the success of program efforts in driving participation and can be used to gain early insights into a program's effectiveness. These results are more certain than forecasted savings and can help to improve the assumptions used for the further development or refinement of conservation programs.

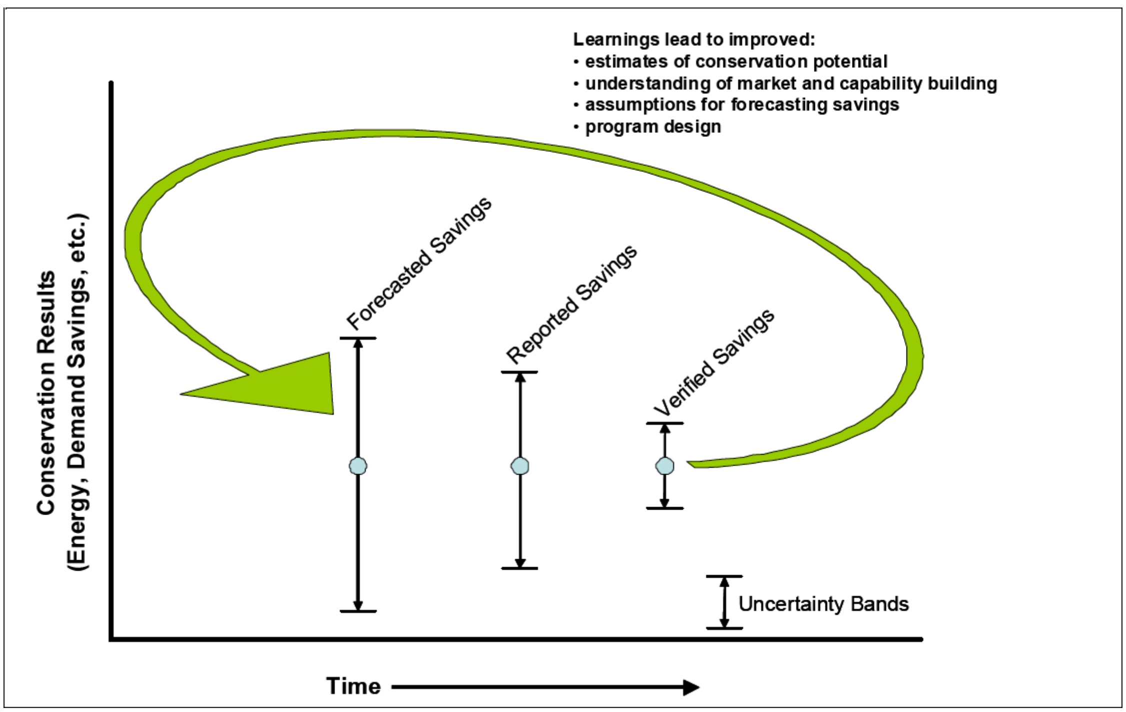
In 2008, the OPA published three quarterly progress reports on its conservation programs, which included reported savings for programs that were currently running. Going forward in 2009, the OPA will only publish verified program savings after program completion, but will continue to monitor, analyze and manage program performance throughout the year based on reported results.

Verified Savings

Measurement and verification studies are conducted to confirm that reported claims of energy and peak demand reductions have actually occurred. The measurement component involves collecting data from various sources, including site visits, surveys, utility bills, equipment invoices, sensors, occupancy records and/or production reports. The verification component involves using the measured data to verify that anticipated energy and peak demand savings occurred. This means verifying that conservation measures have been implemented to a reasonable standard of quality, are operating as intended and are capable of generating energy and peak demand savings.

Verified results represent the best estimate of a conservation program's actual savings and greatly reduce the level of uncertainty surrounding program results. Verified results can be greater or less than forecasted and reported results, depending on factors beyond the program administrator's control. Although verified savings represent the results with the highest degree of certainty, these factors mean that some level of uncertainty will always be associated with reporting on conservation program results. The credibility of verified results is improved by separating the responsibility for program design and implementation from the responsibility for verification.

The following figure illustrates the uncertainty surrounding the results of the three reporting tracks. The decreasing uncertainty as results move from forecasted and reported to verified indicate that measurement and verification can provide results that are more reliable, predictable and transparent. The verification process can provide regular feedback about program performance, leading to the development of more effective programs and activities. The assessments also assist in refining estimates of conservation potential, improving understanding of market and capability building requirements, and generating better assumptions for forecasting savings. Verified savings, in terms of megawatts or megawatt-hours, can be less than reported savings, but the verified results are more valuable to system planners because the capacity they represent (e.g., demand reduction) can be more consistently equated with capacity of supply resources.



Appendix C - Program Evaluation Highlights

Every Kilowatt Counts Program

Program Description

A retailer-based program that encourages consumers to purchase and install featured energy-saving products by providing them with information and instant discount rebates. The OPA ran spring (April 16-June 17) and fall (Sept. 16-Nov. 30) campaigns in 2007. The fall campaign also included a community-based social marketing initiative, which mobilized volunteers to deliver 500,000 compact fluorescent lightbulbs (CFLs) and coupons door-to-door across 89 communities, as well as organized seasonal light exchange events in 26 communities.

Evaluation Description

Timing: ☒ End of program ☐ Mid-program (timeframe: ___________________)
EM&V Contractor: Navigant Consulting Inc.

Program Results

Table 5 – Program Participation, Energy and Demand Savings

	Coupons redeemed	CFLs distributed door-to-door	Summer demand savings (MW)	First-year energy savings (GWh)	Lifetime energy savings (GWh)
Forecasted	1,150,000	--	3	128	1,400
Reported	2,762,424	500,000	7.8	197	1,240
Verified	**2,773,186**	**500,000**	**4.9**	**132**	**1,060**

The key drivers of the variance between forecasted and verified savings were:

- **Participation rate** -- redemption of coupons was 141 percent above forecast. Solar lights and CFL sales greatly exceeded targets despite being new in the market in the case of solar lights, and having reduced rebate values in the case of CFLs.
- **Energy savings per coupon** -- less than one-third of forecast, due to significant reductions in assumed energy savings per CFL and because the majority of solar lights were purchased for new applications, rather than replacements (therefore did not generate energy savings).
- **Demand savings per coupon** -- approximately two-thirds of forecast. This variance is less than the driver noted above because summer demand savings assumptions for CFLs increased from 0 to 1.3 watt/unit.

Lessons Learned/Recommendations

Key recommendations from EM&V contractor	Response
The OPA should encourage more uniform sales reporting from retailers to facilitate analysis of units per coupon, average price and other key parameters for program analysis.	The submission of retail sales data has already been incorporated into the 2008 Retailer Participation Agreement. Sales data reporting, using a reporting template, is a contractual requirement for participating retailers.
Do not promote outdoor solar lights unless for specific applications that are highly likely to yield savings. Survey results suggested 85 percent were	Program staff were aware of this issue based on the large number of solar coupon redemptions and decided shortly after the 2007 spring campaign to

Key recommendations from EM&V contractor	Response
purchased for new applications rather than replacement or displacement and, therefore, did not produce electricity savings.	eliminate solar lights from the 2008 program.
Seasonal LEDs may not be cost-effective from a total resource cost perspective, due to market transformation. However, they may help build consumer awareness and commitment to undertake other energy-savings measures, acting as a type of "loss leader."	Rebates on this product have already been eliminated for the 2008 EKC program based on significant market transformation in seasonal lighting market over the past two years. Local distribution companies may also choose to promote seasonal LED exchange events as grassroot initiatives in their communities.
Conduct more detailed analysis/surveying within the GTA in the 2008 program to further explore the local opportunities to cost-effectively promote and increase penetration of CFLs in the GTA, relative to other regions.	The EM&V findings of lower CFL penetration and lower free-ridership in the GTA are not consistent with results from other research that the OPA and Toronto Hydro have conducted. Additional analysis will be conducted in 2008 market research.
Consider further investigation of the differences between online and telephone surveys and their impact on program results (e.g., net-to-gross ratio). Evaluation found that the two techniques can yield different results, but it was not possible to determine whether one technique provides a more representative picture of the market than the other.	The OPA will investigate the impact of different survey techniques through evaluation of this program and others in the mass markets portfolio.

Implications for Future Programs

The key drivers of the variance between forecasted and verified savings in the 2007 program were all taken into account in the design of the 2008 program.

- The prescriptive input assumptions (PIAs) used to design the 2008 EKC Power Savings Event program were based on the draft PIA review report prepared by Navigant as part of this evaluation, so the significant reductions in energy savings per CFL are already reflected in 2008 forecast.
- The recommendation regarding the removal of rebates from solar lights and seasonal LEDs was already incorporated into the 2008 program.
- Based on the reduced incentive budget allocated to the program for 2008 and the high number of CFL coupon redemptions in 2007, rebates on standard "twisty" CFLs were removed from the 2008 program.

Great Refrigerator Roundup Program

Program Description

A province-wide program that aims to achieve energy and demand savings through the removal and decommissioning of older, working, inefficient secondary and primary refrigerators, freezers and room air conditioners (ACs). Appliances are picked up and removed free of charge and are decommissioned in an environmentally responsible manner. Program is scheduled to run until end of 2010.

Evaluation Description

Timing: ☐ End of program ☒ Mid-program (timeframe: June 18 - December 31, 2007)
EM&V Contractor: Quantec, LLC

Program Results

Table 6 – Program Participation, Energy and Demand Savings

	Refrig-erators collected	Freezers collected	Room ACs collected	Total appli-ances collected	Summer demand savings (MW)	First-year energy savings (GWh)	Lifetime energy savings (GWh)
Forecasted	40,000	1,500	6,000	47,500	10.6	49.2	295.0
Reported	37,940	11,063	765	49,768	11.4	50.5	303.3
Verified	**35,803**	**12,419**	**1,610**	**49,832**	**1.7**	**13.4**	**117.1**

The key drivers of the variance between forecasted and verified savings were:

- **Input assumptions** – the original assumptions for demand and energy savings were based on the Ontario Energy Board's *Total Resource Cost Guide*; new estimates are substantially lower.
- **Energy/demand savings per appliance --** less than half of the forecasted number of units collected were primary appliances that were later replaced, and a significant number of secondary appliances were only being used part of time, thereby lowering actual energy savings from retirement.
- **Free-ridership** -- EM&V suggests this program's free-ridership is 46 percent, significantly higher than the planning estimate of 10 percent free-ridership.

Lessons Learned/Recommendations

Key recommendations from EM&V contractor	Response
Develop multi-family, small commercial and retailer pilot programs.	A pilot program involving retailers is planned for Q3/Q4 2008. A small commercial pilot program will be considered at a later date.
Focus on marketing (as opposed to incentives).	Truck advertising implemented in June 2008. Also collaborating with the Ministry of Energy and Infrastructure on David Suzuki TV ads.
Create a more dynamic pick-up/appointment system that minimizes the distance travelled between appointments.	The system is relatively new, and its functionality is continually being refined to optimize pick-ups.
Market the environmental impacts of the program.	The effectiveness of the existing marketing materials has already been assessed in a number of consumer

Key recommendations from EM&V contractor	Response
	research studies. This research suggests that the environmental benefits of the program are secondary to messaging on cost savings and convenience. We will continue to monitor customer response to marketing materials.
Further refine website to include pull-down menus for certain fields (e.g., street type) to improve geo-coding customer locations.	This functionality was implemented in August 2008.
Utilize all collected data. Aggregate the savings specific to individual appliance type, size, age and replacement scenarios to yield a more accurate estimate of overall program impacts.	The previous prescriptive input assumptions did not contain this level of detail. Now that this information is available, the calculations of energy savings have been revised commencing in July 2008 (for reporting).
Improve documentation of "small" units. Use the U.S. federal definition of a compact refrigerator and/or freezer as less than 7.75 cubic feet. Determine whether any appliance types other than "single door" are less than 7.75 cubic feet.	As noted below, smaller refrigerators and freezers were removed from the program commencing in July 2008.
Utilize the savings associated with the oldest, appropriately sized "single door" appliance as estimate of savings from sulphur dioxide units. Conduct additional research (e.g., metering studies) if the quantity of these units increases.	This recommendation will be adopted.
Document and use cooling capacity (energy-efficiency rating or BTU/hr) rather than cubic feet to determine room air conditioner savings.	The small proportion of room ACs collected (one to two percent of all appliances) may not warrant this change. This will be further investigated in the Conservation Fund pilot project noted below.

Additional actions under consideration by the OPA:

- **Ensure data captured on appliance size and age is *accurate***. In some cases, pick-up crews were not accurately recording the age/size of appliances, but using the "default" selection (10 yrs old; < 10 cu. ft.). ARCA has already taken steps to address this matter with pick-up crews and to remove the "default" setting in the database. In addition, an independent third party has been secured to conduct periodic audits and inspections of the ARCA operations. **Timing: July 2008**.
- **Consider reducing LDC local marketing budgets**. Based on the findings and recommendations of this study, reductions in marketing expenditures will be explored. **Timing: January 2009**.
- **Remove smaller refrigerators and freezers from the program**. It has been determined that it is not cost-effective to collect smaller appliances (i.e., those less than 10 cubic feet). **Timing: July 2008.**
- **Seek opportunities to increase proportion of room ACs being picked up. Also include dehumidifiers.** A pilot test, funded through the Conservation Fund, will provide consumers the opportunity to turn-in an older room air conditioner or dehumidifier and receive an incentive coupon for the purchase of a new ENERGY STAR qualified unit. **Timing: Pilot test in May-June 2008, roll-out in Q3/Q4 2008.**

- **Adjust program eligibility requirements so that refrigerators and freezers must have been manufactured in 1993 or earlier** (versus current requirement of 10 years old or older). This will help preserve the peak demand and annual energy savings being achieved. **Timing: January 2009** (changes prior to then would directionally impact on LDC targets under Schedule A-2.)
- **Conduct additional research to fully understand the market for used appliances, and consumer behaviour on replacing and retiring appliances**. Such information will directly impact on free-ridership estimates. **Timing: Q3/Q4 2008**.

Implications for Future Programs

With no changes to the program design, an estimated 11 MW could be attained during the 2008-10 period based on current demand projections. With the changes discussed above, the peak demand savings that can be attained by 2010 would be 16 MW. Additional means to improve the peak demand and energy savings and/or reduce program costs will be investigated.

The GRRP also provides other intangible benefits to the OPA portfolio of conservation programs. For example, the program is highly visible, and it is easy for the public to understand the reductions in energy savings it offers. Participants have been highly satisfied with the program and have offered that their positive experience with the GRRP makes it highly likely that they will take part in other programs offered by the OPA.

Hot Savings Rebate Program & Cool Savings Rebate Program

Program Description

The province-wide programs, delivered through the Heating, Refrigeration and Air Conditioning Institute of Canada (HRAI), provided incentives to Ontario residential electricity consumers to increase the efficiency of their existing cooling and heating systems through the following measures: ENERGY STAR central air conditioners (CACs), CAC tune-ups, programmable thermostats and variable speed furnace motors (ECMs). The Hot Savings Rebate Program ran from October 1, 2006, to March 31, 2007. The Cool Savings Rebate Program ran from April 1, 2007, to March 31, 2008.

Evaluation Description

Timing: ☒ End of program ☐ Mid-program (Timeframe: October 1, 2006 - March 31, 2008)
EM&V Contractor: Navigant Consulting Inc.

Program Results

Table 7 – Program Participation, Energy and Demand Savings

	Number of rebates (Both programs)							
	E-STAR CAC	Progr. Thermo-stats	ECM	CAC tune-up	Total rebates	Summer demand savings (MW)	First-year energy savings (GWh)	Lifetime energy savings (GWh)
Forecasted	32,141	29,370	42,807	25,311	129,629	38.3*	n/a	470*
Reported	n/a	n/a	n/a	n/a	128,454	35.6**	42**	562**
Verified	**33,178**	**46,989**	**51,990**	**28,048**	**160,205**	**19.8**	**30.2**	**451.1**

*As presented to the Board of Directors for program approval. These are gross estimates.
**As published in 2006, 2007 and 2008 reports. These are a mix of net and gross savings, based on changing reporting practices.

The key drivers of the variance between forecasted and verified savings were:

- **Reporting practices** -- Gross savings forecasts were provided to the Board, while a mix of gross and net savings have been reported in three reports that span the 18-month timeframe of these programs.
- **Net-to-gross (NTG) adjustments** -- The forecasted NTG adjustments ranged from 0.7 to 0.9 for different measures and were based solely on free-ridership estimates. The NTG adjustments assessed in the evaluation were significantly lower, ranging from 0.16 to 0.59, due to both higher free-ridership values as well as the exclusion of 40 percent of programmable thermostat rebates and 62.5 percent of CAC tune-up rebates to reflect customers who already had these measures installed prior to participating in the program.

Lessons Learned/Recommendations

Key recommendations from EM&V contractor	Response
Better define governance and accountability structure between each of the key stakeholders, in particular between the OPA and HRAI. Suggestions include: ❑ Establish a clear mission statement that identifies the key objectives of the program ❑ Define roles and responsibilities ❑ Involve senior management in regular executive review	Steps have already been taken commencing in May 2008 to improve the governance and accountability structure. Roles and responsibilities have been clarified in the contract with HRAI. A monthly executive review meeting, involving the

Key recommendations from EM&V contractor	Response
meetings.	president of the HRAI and the OPA's director, mass market and conservation awareness, has been instituted.
❑ Retain control over the auditing of installed measures and hold HRAI accountable for addressing any anomalies that are observed. ❑ Perform frequent spot investigations of rebate applications that raise "red flags" by the rebate processor. ❑ Adjust the rules of rebate eligibility to ensure that recipients agree to a home visit (in principal) to qualify for their rebate. Verify between one and three percent of installed measures (skewed towards CACs and ECM-equipped furnaces).	The OPA agrees that audit and control measures should reside with a third party other than HRAI. Eligibility rules will be adjusted as appropriate to allow for spot-checks of installations. An independent third party will be secured to conduct periodic audits and inspections of installations. Timing: Q4 2008.
Enhance contractor enrolment and training ❑ Current online training module provides an acceptable level of information and instruction but is too susceptible to completion by peripheral contracting company personnel and should not be relied upon as the sole vehicle for program training. ❑ HRAI should develop an outreach program to educate non-participant contractors on the merits of enrolling in the program. ❑ Contractor non-compliance with program rules should be addressed quickly and with an appropriate response, ranging from additional training to, if absolutely necessary, dismissal from the program. ❑ HRAI should conduct an annual contractor eligibility review.	An automated rebate submission process is being explored for the 2009 version of the program. New training materials will be developed in accordance with the automated process. Improved contractor eligibility standards and monitoring processes will also be developed. Timing: Q3/Q4 2008.

Additional actions under consideration by the OPA:

- **Re-examine eligible products and services**. HRAI and the OPA will reconsider the inclusion of programmable thermostats in future versions of the program, given the substantial incidents of replacement of existing programmable thermostats. Other program changes and enhancements will also be explored. Timing: Q3 2008. It is intended that a proposal for the 2009 version of the program will be submitted for Board approval in Fall 2008.

Implications for Future Programs

In the justification for the 2008 version of the program (from April 1 to December 31), it was predicted that total demand savings of 14.5 MW would be achieved. With the revised PIAs and assuming no change in the number of rebates processed, the expected demand savings would be 14.1 MW.

Summer Savings Program

Program Description

The Summer Savings program was designed to build awareness of Ontario's growing summer electricity requirements and the need for conservation during the summer months when air conditioning use dramatically increases the demand for electricity. The program offered a financial incentive for consumers to reduce electricity consumption by 10 percent compared with their consumption in 2006, between July 1 and August 31, 2007. If this reduction was achieved, consumers received a credit of 10 percent of their summer electricity bill costs on their utility bill.

Evaluation Description

Timing: ☒ End of program ☐ Mid-program (Timeframe: _________)
EM&V Contractor: Navigant Consulting Inc.

Program Results

Table 8 – Program Participation, Energy and Demand Savings

	Participants	Summer demand savings (MW)	First-year energy savings (GWh)	Lifetime energy savings (GWh)
Forecasted	720,000	46	146	146
Reported	823,622	65	217.5	217.5
Verified	**380,000***	**45**	**81**	**145**

*Note that 858,093 customers qualified and received the bill credit; however, only 12 percent of those customers were considered participants based on awareness of the program and taking action to conserve. Overall 9.2 percent (380,000) of residential customers were aware of the program and actively tried to reach 10-percent target -- including those that were ineligible for the program and those that were eligible but did not reach 10-percent target.

The verified demand savings and lifetime energy savings for the program are almost exactly as forecasted; however, the savings were not achieved in the manner in which the program design had intended. Specifically, only 12 percent of customers that received a bill credit were actually found to be participants in the program (i.e., they knew about the program and actively tried to reduce their consumption). Additionally, only 30 percent of participants actually qualified for the bill credit. The total savings attributed to the program in Table 1 on page 3 includes savings from these participants who failed to qualify.

Lessons Learned/Implications for Future Programs

1. The 2007 Summer Savings program was redesigned in 2008 to address the high free-ridership rate (88 percent according to the Navigant report) and to drive active customer participation. In the redesigned program, renamed Summer Sweepstakes, customers were required to register to be eligible to win various prizes. Tier One prizes, of lesser market value, were offered simply for registering to participate. Tier Two prizes, of much greater value, were offered to customers who achieved a minimum 10-percent e1ectricity consumption reduction from the same period last year.
2. We expect the volume of customers who signed up to participate in Summer Sweepstakes will be considerably less than the total number of eligible participants last year. Customers who registered for the 2008 program will most likely be much more predisposed to actively reduce their electricity consumption. During the program period, participants who registered were sent reminders of the

program along with suggestions on ways to conserve electricity to achieve a minimum 10-percent reduction.

3. The Summer Sweepstakes program has been redesigned to focus more on conservation awareness vs. MW savings. The main focus now is to affect behavioural change through education and through cross-promotion of other conservation programs.
4. While the 2007 Summer Savings program achieved 45 MW savings, this should be regarded as a one-time MW savings driven primarily by reduction in AC use. The MW savings are attributed to the huge participation rate (i.e., 4.5 million eligible households). The vast majority of households did not knowingly participate in the program but still received a 10-percent credit on their electricity bill. This is why the program was redesigned in 2008.

BOMA Toronto Program

Program Description

The OPA has entered into an agreement with Toronto Building Owners and Managers Association (BOMA) for delivery of 150 MW of peak demand savings over a three-year period. The program provides incentives for retrofits that provide sustainable electrical demand and energy reductions in existing, privately owned commercial buildings larger than 25,000 square feet within the City of Toronto. Multi-residential buildings, municipalities, schools, universities and hospitals are excluded from the program. Applicants are eligible for incentives up to 40 percent of the capital cost of the investment. Rebates are estimated based on summer demand savings ($400/kW) or reduction in energy use ($0.05/kWh).

Evaluation Description

Timing: ☐ End of program ☒ Mid-program (Timeframe: March 1, 2007 - February 29, 2008)
EM&V Contractor: SeeLine Group & Quantec LLC
The program includes specific, rigorous, project-level measurement and verification requirements (including following *International Performance Monitoring and Verification Protocols* and using third-party M&V advisors). This evaluation focused primarily on process elements. A variety of techniques were employed to evaluate the program, including both primary and secondary research. The primary research focused on interviews with the various stakeholders, participants and non-participants, while the secondary research focused on detailed reviews of data and processes and aggregation of the results.

Program Results

Table 9 – Program Participation, Energy and Demand Savings

	Participants	Summer demand savings (MW)	First-year energy savings (GWh)	Lifetime energy savings (GWh)
Forecasted	100	15	N/A	N/A
Projects in progress -- submitted applications	34	2.1	25.6	N/A
Projects in progress -- approved applications	27	4.4	20.4	N/A
Verified (completed projects)	**12**	**0.7**	**5.6**	**79.3**

The two key drivers of the variance between forecasted and verified savings were:

- **Participation rate** -- number of completed projects was only 12 percent of forecast.
- **Savings per project** -- the average kilowatt savings per project to date (100 kW/project) was significantly lower than the 150 kW savings/project forecasted during program design. It is possible that future projects will have larger demand savings than the first projects, as larger projects take longer to "ramp up," and some participants may have been testing the program with smaller projects before participating with larger undertakings.

Lessons Learned/Recommendations

Key findings and recommendations from the evaluation contractor were:

- Simplicity is a major strength of the program.
- The program tracking system is a solid program feature and an excellent foundation for meeting reporting requirements.

- The business-to-business marketing strategy is sound. Program communications should be developed that target both individuals and departments responsible for capital investment decisions as well as those responsible for building operations (often not the same department). Strategic program communication via senior asset managers and more continuous marketing of the program are advised.
- The BOMA Toronto label presents a strong opportunity for leverage.
- The M&V component is one of the strongest components of the program. Independent third-party, project-level M&V generates solid savings estimates and provides a quality “paper trail” that simplifies checking and verifying calculations.
- Current program staffing level is inadequate. There should be more “presence” in the market by senior program resources.
- Survey respondents indicated they would recommend the program – a participant referral initiative should be considered.
- The program may be “saddled” with unrealistic targets. Program targets were developed using simple rules of thumb rather than detailed potential studies, and the participant scope has changed since the original targets were developed (e.g., multi-residential buildings were originally included within the program). At the current kW/project rate, 60 participants a month would be required to meet program target of 150 MW.

Response to lesson learned/recommendations

As an overview, the program design is sound and has particularly rigorous M&V processes embedded in the program. The lower-than-anticipated results are largely due to slow take-up – this is a result of year-one efforts being focused on development of robust, scalable business infrastructure. Additional resources have been retained (BOMA Toronto has added a program director and the OPA has assigned an OPA employee to provide sales support on an interim basis) and, with systems in place, resources will increasingly focus on marketing. The project pipeline is expanding as is the number of larger projects. Larger projects also have a longer lead time and are expected to materialize in year two of the program. Participants surveyed reported positive experience. This program provides a solid foundation to build on.

Demand Response 1 Program

Program Description

The Demand Response 1 (DR1) program's objective is to encourage short-term demand response capacity in response to the Independent Electricity System Operator's three-hour ahead pre-dispatch price signal in the electricity market. The DR1 program is a "market-based," voluntary program, designed for participation by consumers who can curtail load in response to economic signals, primarily using existing equipment and processes.

Evaluation Description

Timing: ☐ End of program ☒ Mid-program (Timeframe: January 1 - November 30, 2007)
EM&V Contractor: Price Waterhouse Coopers

Third-party measurement and verification of energy savings and demand reduction achieved is built into the demand response contracts.

Program Results

Table 10 – Program Participation, Energy and Demand Savings

	Number of participants	Nameplate capacity (MW)	Energy curtailed (GWh)	Max curtailment (% of capacity)	Average curtailment (% of capacity)	Curtailment on 2007 peak hour
Forecasted	20	200	36	200 (100%)	60 (30%)	200 (100%)
Reported	10	317.4	--	225.9 (81%)	113 (41%)	141.9 (52%)
Verified	**10**	**317.4**	**175**	**225.9 (81%)**	**113 (41%)**	**141.9 (52%)**

The key drivers of the variance between forecasted and verified savings were:

- The number of participants was lower than forecasted, reflecting the amount of education required by participants and the usual long-term nature of implementing initiatives within industrial operations.
- With respect to nameplate MW, the larger-than-expected number was the result of three very large loads participating in the program, with each load having greater than 50 MW of demand response capability.
- Curtailment on the 2007 peak hour was less than anticipated, illustrating that market price is not a perfect indicator of when demand might be the highest in Ontario.

Lessons Learned/Recommendations

The conventional evaluation of conservation and demand management resources based on avoided cost of generation, transmission and distribution does not entirely capture the benefits of demand resources, especially the insurance or option value and time value.

DR resources are capacity resources. Since there is no capacity market operating in Ontario, the ex-post evaluation of DR resources is limited by the energy-only market, which does not capture the value of capacity offered by DR resources. In addition, the ex-post evaluation based on energy prices does not capture the reliability, market power mitigation and option values of DR resources.

The OPA EM&V team is developing a DR-specific evaluation framework that could capture and value the market surplus, option and insurance value provided by DR resources, but the details are still under consideration.

- **Measures and Assumptions –** There are no standard measures and assumptions for DR resources. The measurement and verification of energy savings and demand reduction is based on metering information and standard measurement and verification protocol, as per the provisions of DR contracts.

- **Adjustment Factors (free-rider rates, net-to-gross, etc.) –** The free-rider rate is zero and net-to-gross ratio is one for the DR programs if the pre-program elasticity in the electricity market or the participant is taken into account while doing cost-effectiveness analysis.

- **Program Participation –** Program process evaluation was done in 2007 for 2006 DR1 program.

Implications for Future Programs

It is apparent that a single program to pursue demand response objectives is not sufficient. Given that the correlation between peak prices and peak demand is not perfect, the need to develop other demand response initiatives that are enabled based upon other types of triggers is necessary to ensure a fully effective capability in reducing system peak demand.

ONTARIO POWER AUTHORITY

2008 Final Conservation Results

January 2010

Ontario Power Authority

About the Ontario Power Authority

The Ontario Power Authority (OPA) is responsible for ensuring a reliable, sustainable supply of electricity for Ontario. Its key areas of focus are leading and coordinating conservation efforts across the province, planning the power system for the long term and ensuring development of needed generation resources.

The OPA was established by the *Electricity Restructuring Act, 2004* (amending the *Electricity Act, 1998*) and began operations in January 2005. A not-for-profit corporation without share capital, the OPA is governed by an independent Board of Directors, and programs are directed by a Chief Executive Officer. It reports to the Ontario Legislative Assembly through the Minister of Energy and Infrastructure. The OPA is licensed and regulated by the Ontario Energy Board.

About this Report

This report highlights the significant progress towards Ontario's conservation goals that was made through OPA-funded conservation initiatives implemented in 2008. It does not include savings from non-OPA-funded conservation activities, such as codes and standards and provincial and federal government programs funded through taxpayers, which also contribute toward Ontario's conservation goals.

2008 Highlights

2008 was an exciting year for the OPA, and there were many important changes, including the appointment of a new Minister of Energy and Infrastructure, the Honourable George Smitherman, in June 2008 and the appointment of a new Chief Executive Officer, Colin Andersen, in September.

It was also a year of significant activity and progress for the OPA's conservation portfolio. Conservation highlights for 2008 included:

1) **confirming that Ontario's first conservation target was met.** In June 2008, the OPA reported that Ontario had met its interim target of 1,350 megawatts (MW) of peak-demand reduction by the end of 2007, the first milestone in the province's long-term target of 6,300 MW of peak-demand reduction by the end of 2025.

2) **making strides towards Ontario's 2010 target.** The OPA's conservation portfolio achieved 387 MW of peak-demand reduction and 386 gigawatt-hours (GWh) of annual energy savings as a result of 2008 conservation activities, indicating progress toward the next interim target of an additional 1,350 MW of peak-demand reduction by 2010.

3) **expanding conservation offerings across all sectors.** In 2008, the OPA launched five new initiatives, broadening its reach within all market sectors through its consumer (residential), business (commercial and institutional) and industrial programs.

4) **enhancing successful partnerships with local distribution companies.** The OPA partnered with more than 70 local distribution companies (LDCs) in the delivery of conservation programs, reaching 99 percent of Ontario's electricity customers.

5) **launching Ontario's first Energy Conservation Week.** Designed to engage as many Ontarians as possible in advance of the summer peak demand, the grassroots campaign lead to more than 74 percent awareness and 50 percent participation across the province.

Introduction

Ontario has a long-term conservation target to achieve at least 6,300 megawatts (MW) of peak electricity demand reduction by 2025.[1] Aggressive interim targets included a 1,350 MW peak-demand reduction by 2007, which has been achieved, and an additional 1,350 MW reduction by the end of 2010.

The OPA has a leadership role in coordinating the province's electricity conservation efforts and working in partnership with local distribution companies (LDCs) and others to ensure Ontario's conservation targets are met.

The OPA is focused on long-term planning and adopting a market-transformation approach to ensure that conservation is sustainable, reliable and cost-effective. In parallel with this long-term planning, the OPA develops and manages conservation programs to encourage immediate conservation actions by consumers and businesses to help meet the near-term provincial targets. Programs span all customer segments – consumer (residential customers, including low-income), business (commercial and institutional customers) and industrial. These programs use tools as diverse as product rebates, building retrofits and direct installation services to encourage participants to undertake conservation actions.

Evaluation, Measurement and Verification

The OPA is committed to transparency in reporting on the progress and results of its programs. As outlined in its evaluation, measurement and verification (EM&V) framework,[2] the OPA is also committed to undertaking rigorous independent evaluations of the programs it funds in accordance with internationally credible standards.

The primary purpose of evaluating programs is to verify and ensure the reliability of demand reductions and energy savings achieved. This is important because it helps determine the amount of generation that must be built to meet provincial energy needs. Evaluations are also used to assess program design performance, to provide information for continuous management improvement and to validate input assumptions made for specific end-use measures. All OPA-funded programs will undergo an EM&V process at least once between 2008 and 2010. Program evaluations will range from internal process and/or impact evaluations to full, independent third-party evaluations complete with measure reviews, participant surveys and project measurement and verification.

The OPA evaluated 14 of the initiatives that were delivered in 2008 (please see Appendix A for detailed list). In all cases, the 2008 results presented in this report are considered final.

[1] On September 17, 2008, the Minister of Energy and Infrastructure issued a directive asking the OPA to review the viability of accelerating the achievement of stated conservation targets.
[2] The OPA EM&V framework can be found at http://www.powerauthority.on.ca/Page.asp?PageID=1224&SiteNodeID=404.

Portfolio Results

In 2008, the OPA began to consolidate its conservation initiatives into four programs, each aligned with the distinct sector it serves. Recognizing that having a large number of discrete conservation initiatives in the Ontario marketplace can be confusing, the OPA is moving to a comprehensive, integrated and customer-centric approach that will better serve program participants and help achieve greater conservation results.

Table 1 provides an overview of the target market for each program and the initiatives that were offered by the OPA in 2008 as part of each program. The OPA will continue to expand the offerings and reach of these programs to cover additional conservation opportunities.

Table 1: OPA 2008 Conservation Portfolio

Program	Target Market	2008 Conservation Initiatives
Consumer	Residential households	▪ Free pickup of old, working, inefficient appliances ▪ Rebates on high-efficiency, replacement cooling and heating systems ▪ In-store coupons on energy-efficient products ▪ Direct load-control devices for air conditioning and electric water heaters ▪ Contest to encourage summer electricity conservation ▪ Aboriginal retrofit pilot (five communities) ▪ Clothesline giveaways, holiday light exchanges (Toronto only) ▪ Incentives for retrofit (lighting, motors and HVAC) of multi-family buildings ▪ Renewable Energy Standard Offer Program (RESOP)
Low-Income Consumer	Low-income residential households	▪ Free compact fluorescent light bulbs (Toronto only)
Business	Commercial/ institutional facilities	▪ Incentives for retrofit (lighting, motors and HVAC) of existing buildings ▪ Incentives for energy-efficient new construction ▪ Direct load-control devices for air conditioning and electric water heaters for small commercial businesses ▪ Voluntary load shedding (DR1) ▪ Contractual load shedding (DR3) ▪ Incentives for peak shedding (Hydro One only) ▪ Customer-based generation (RESOP, and combined heat and power)
Industrial	Industrial facilities	▪ Voluntary load shedding (DR1) ▪ Contractual load shedding (DR3) ▪ Incentives for peak shedding (Hydro One only) ▪ Customer-based generation (RESOP, and combined heat and power)

Resource Savings[3]

The OPA's 2008 conservation programs achieved a net[4] savings of more than 387 MW of summer peak-demand reduction and more than 386 GWh of energy savings, exceeding the portfolio-level forecasted savings by more than 30 percent.

[3] All savings shown in this report are expressed at the generator level, meaning that they include both the savings at the end-user (customer) level where the conservation measure is installed as well as avoided transmission and distribution losses associated with those savings.

[4] Gross savings represent all savings associated with program activities. Net savings are the portion of gross savings that are *directly* attributable to the program. All savings shown in this report are net savings. The primary adjustment factor between gross and net savings is free ridership. Free ridership occurs when customers take advantage of rebates or cost savings available through conservation programs even though they would have installed the energy-efficient equipment on their own. Such customers are commonly referred to as "free riders." These customers may already be motivated to purchase energy-efficient equipment even without utility-sponsored incentives.

Table 2: 2008 OPA Conservation Portfolio Results – Forecasts vs. Actuals

Metric	Forecast	Final Results
2008 peak-demand savings (MW)	312	387
2008 energy savings (GWh)	181	386
Lifetime energy savings (GWh)	1,197	4,621

The 2008 conservation portfolio was balanced, with programs working together to achieve overall conservation goals, as seen in Figure 1. The industrial program, comprised primarily of demand response initiatives, focused on procuring peak-demand resources, while the consumer and business programs drove long-lasting energy savings through energy-efficiency initiatives. Additionally, lower-than-forecasted savings in the business program were offset by higher-than-forecasted savings in the consumer and industrial programs. Details on the specific initiatives within each of these programs and their relative contributions to the program results are provided in subsequent sections.

Figure 1: Breakdown of 2008 OPA Portfolio Savings by Program

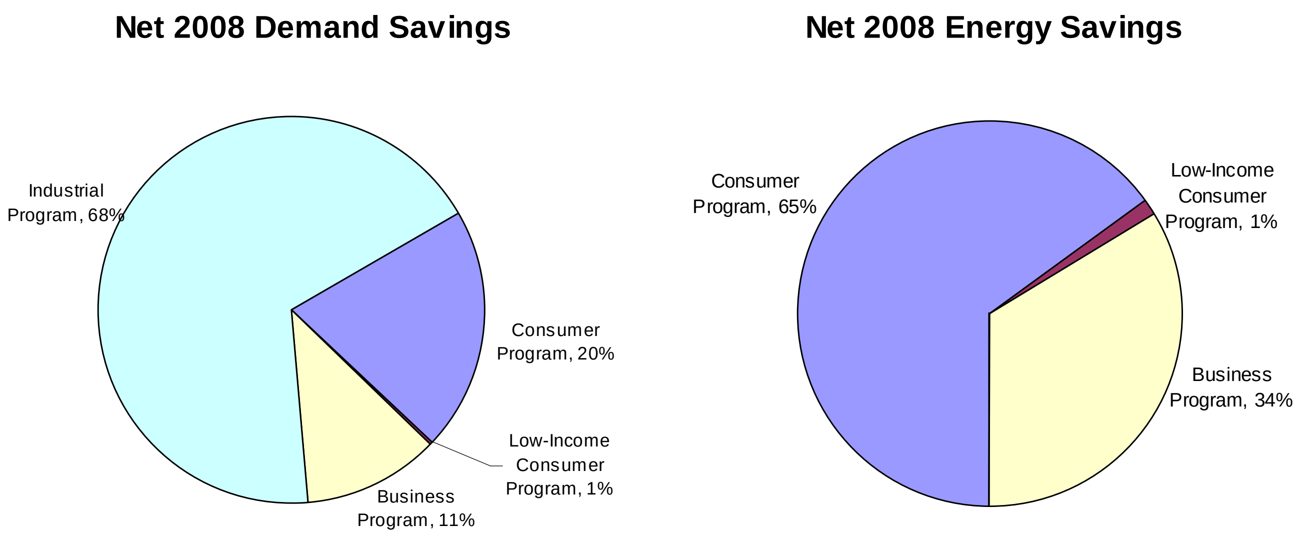
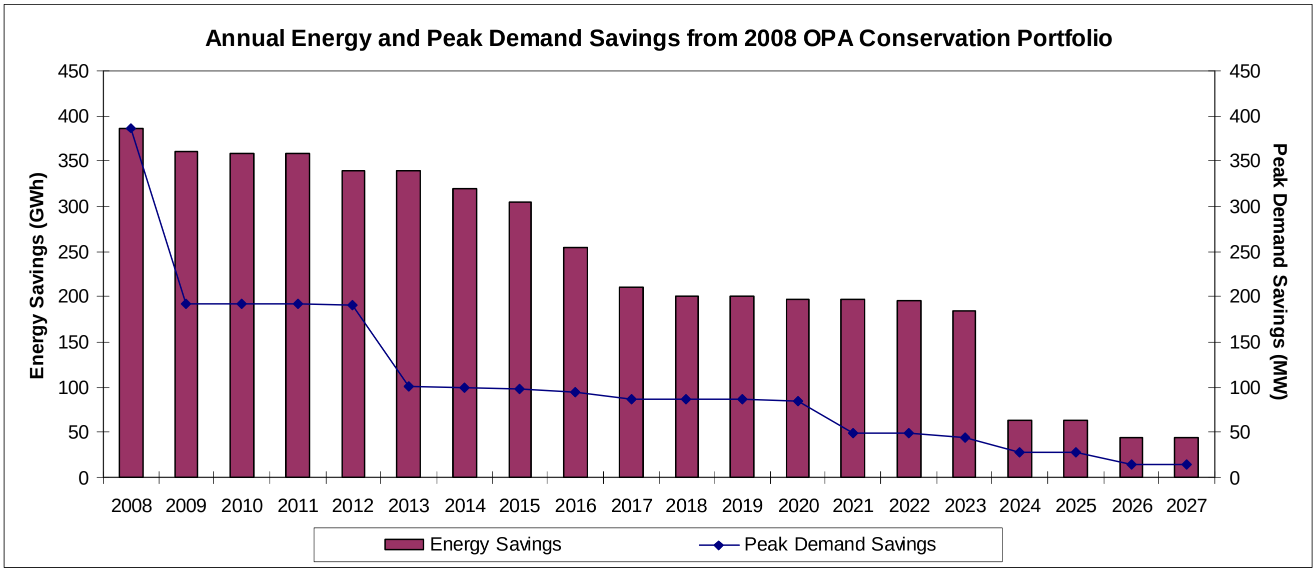


Figure 2 below illustrates an important and powerful characteristic of conservation – that savings typically last beyond the investment period. In other words, conservation program costs are all paid "up front" when the measure is installed; however, the benefits continue for many years. The expected duration or "persistence" of conservation is estimated based on the specific conservation measures that are installed and how long those measures are estimated to last. For example, a new energy-efficient furnace may last 18 years while behavioural actions might last only one year. As seen in this graph, the majority of energy savings from OPA's 2008 conservation activities are expected to persist for at least 15 years.

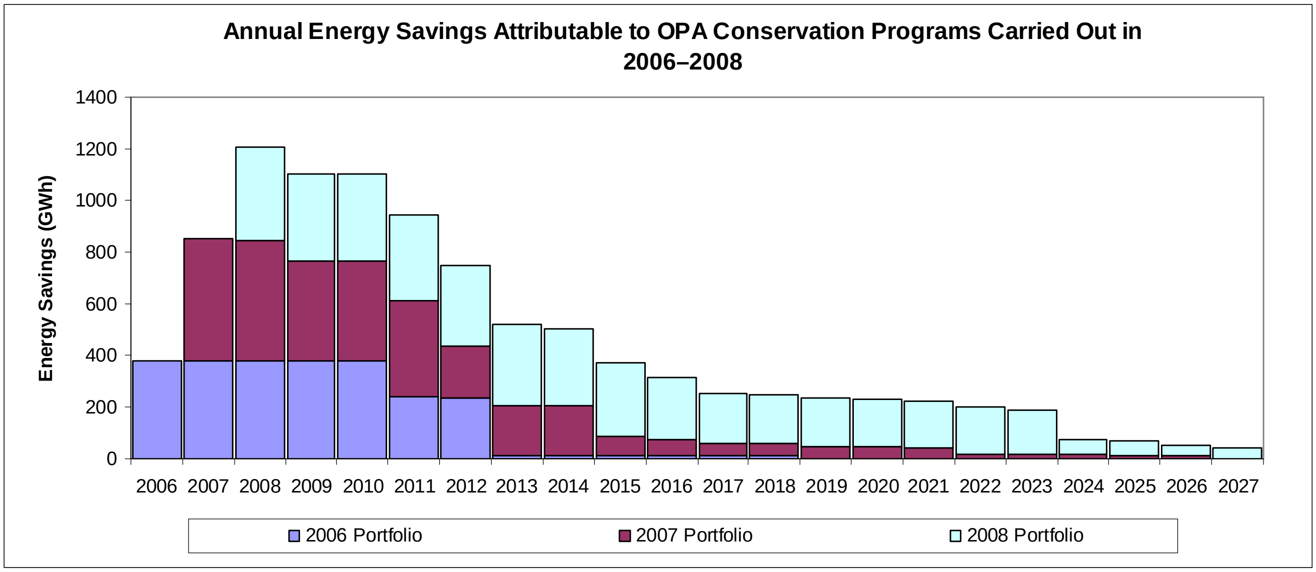
Figure 2: Expected Duration of Savings from 2008 OPA Conservation Portfolio



OPA-funded Conservation Results to Date

The OPA began implementing conservation programs in 2006. The total annual energy savings that have occurred to date, as well as those that are expected to continue in the future as a result of OPA-funded conservation programs in 2006, 2007 and 2008, are shown in the figure below.

Figure 3: Energy Savings from 2006-2008 OPA Programs



Cost-Effectiveness

The OPA assesses the cost-effectiveness of its conservation programs using a suite of standard industry benefit-cost analyses and metrics – the total resource cost (TRC) test, the program administrator cost (PAC) test and the levelized cost of conservation delivery.

The TRC test looks at cost-effectiveness from the perspective of society as a whole, taking into account all benefits and all costs, while the PAC test (also referred to as the utility cost test) considers cost-effectiveness from the perspective of the utility or program administration agency. Levelized conservation delivery costs reflect the total cost incurred by the OPA in procuring conservation resources and provide a basis for comparing the cost of conservation resources with the cost of electricity supply resources. Additional detail on these metrics is provided in Appendix B.

Table 3 summarizes portfolio cost-effectiveness results both for actual conservation resources implemented in 2008[5] and for those conservation resources implemented in 2008 combined with conservation resources projected for implementation in 2009 and 2010. The OPA conservation portfolio passes both cost-effectiveness tests (i.e., a positive net benefit) for both the 2008 program year alone as well as for the three-year portfolio period, providing assurance that the OPA is successfully procuring cost-effective conservation.

Table 3: Assessment of OPA Conservation Portfolio Cost-Effectiveness

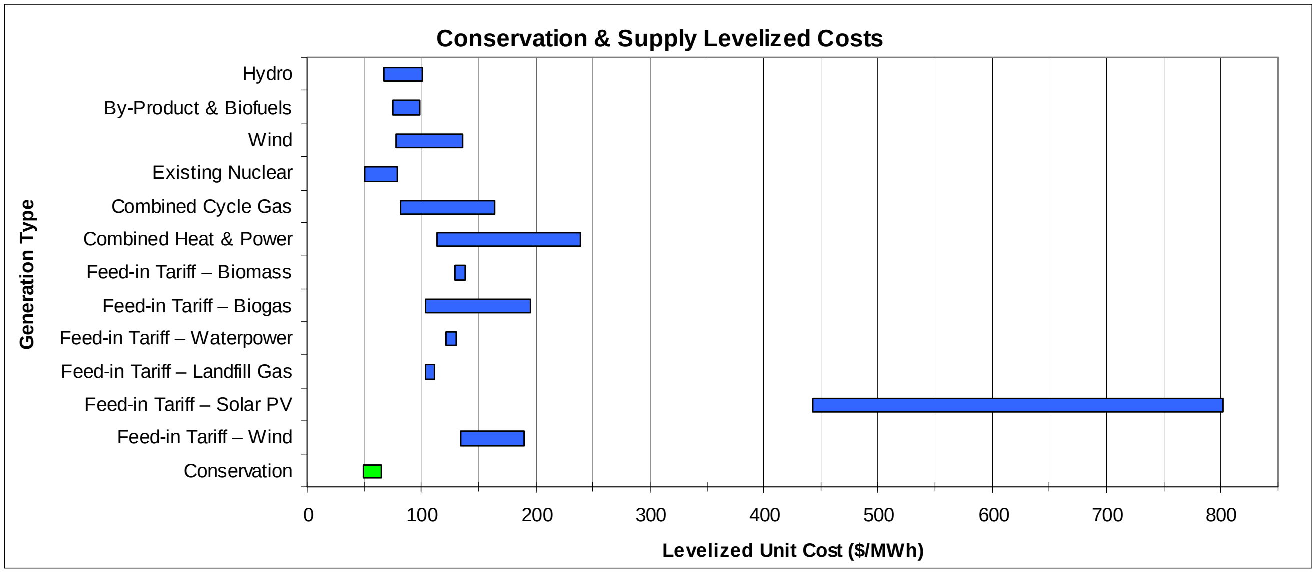
Costs expressed in present value 2008$		**2008 Program Year (Final Results)**	**2008 - 2010 Portfolio (Projection)**
Program Administrator Cost Test	Benefit (millions)	$293	$1,051
	Cost (millions)	$143	$ 611
	Net Benefit (millions)	$150	$ 440
	Net Benefit Ratio	2.0	1.7
Total Resource Cost Test	Benefit (millions)	$293	$1,051
	Cost (millions)	$187	$756
	Net Benefit (millions)	$106	$295
	Net Benefit Ratio	1.6	1.4
Levelized Delivery Cost	$/MWh	$49	$65
	$/MW-yr	$95,864	$134,703

As seen in Figure 4, the cost of conservation is significantly lower than the cost of most types of electricity supply, when compared on a levelized basis.[6]

[5] This cost-effectiveness analysis includes only conservation initiatives administered by the OPA's conservation division. It does not include customer-based generation or contracted demand response initiatives that are administered by the OPA's electricity resources division.

[6] Source of non-Feed-in Tariff supply costs: OPA Generation Procurement Cost Disclosures http://www.powerauthority.on.ca/Page.asp?PageID=122&ContentID=6670&SiteNodeID=454&BL_ExpandID=
Source of Feed-in Tariff costs: http://fit.powerauthority.on.ca/Storage/99/10863_FIT_Pricing_Schedule_for_website.pdf

Figure 4: Comparison of Levelized Costs of Conservation and Supply



Program Results

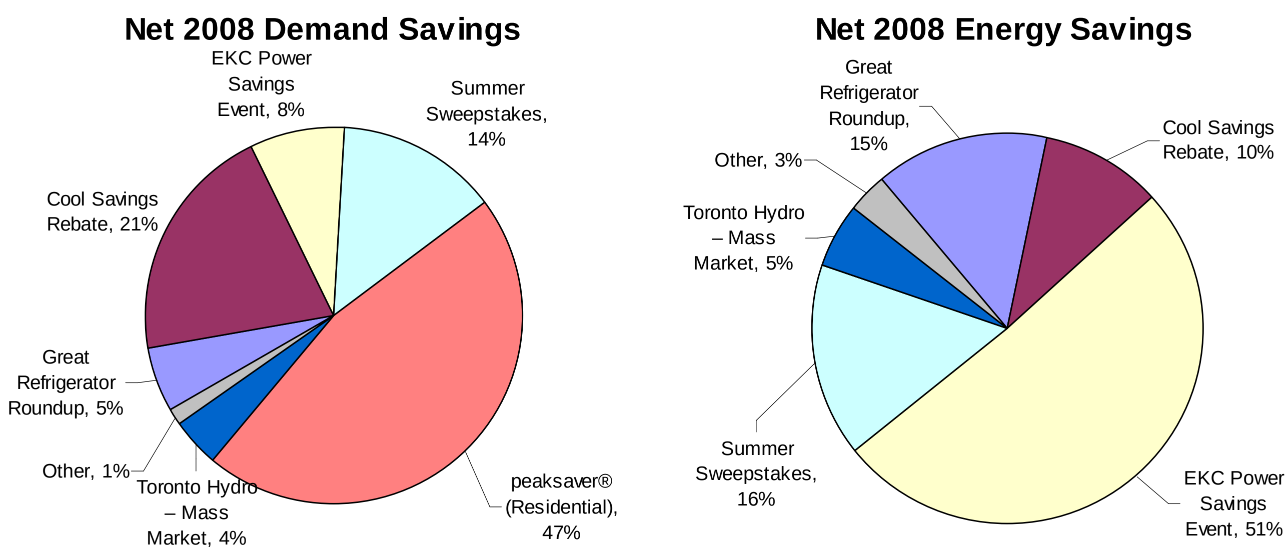
Consumer Program

The consumer program performed very well in 2008, achieving 120 percent of forecasted net demand savings. Figure 5 shows the breakdown of 2008 consumer program savings by major initiative. As was seen with the portfolio as a whole, there is a balance of initiatives within the consumer program. The majority of demand savings are stemming from the ***peaksaver®*** initiative, while the Every Kilowatt Counts (EKC) Power Savings Event is contributing the majority of energy savings in the consumer program.

Table 4: 2008 Consumer Program Final Results: Forecast vs. Actual

Metric	Forecast	Actual
2008 peak-demand savings (MW)	61	73
2008 energy savings (GWh)	91	234
Lifetime energy savings (GWh)	888	2,235

Figure 5: Breakdown of 2008 Consumer Program Savings by Initiative



The maturity of the consumer program (many initiatives have been in market since 2006) has enabled the OPA to refine and improve program forecasting and management over time. Additionally, the comprehensive EM&V process that was undertaken on four consumer initiatives in 2007 significantly contributed to the refinement and improvement of the consumer program as a whole in 2008.

Low-Income Consumer Program

Low-income consumers across Ontario were eligible to participate in all OPA consumer program initiatives in 2008; however, there was not a stand-alone, province-wide program geared specifically to low-income households.

In 2008, Toronto Hydro, as part of its portfolio of initiatives funded through the OPA, delivered an initiative that provided free compact fluorescent light bulbs (CFLs) to low-income customers in Toronto. The Toronto Hydro CFL initiative for low-income households achieved a net savings of 1.9 MW and 4.5 GWh in 2008 and an expected lifetime savings of 36 GWh.

The Ministry of Energy and Infrastructure is working to develop a comprehensive, province-wide, low-income residential initiative policy and direction for the delivery of conservation to this sector.

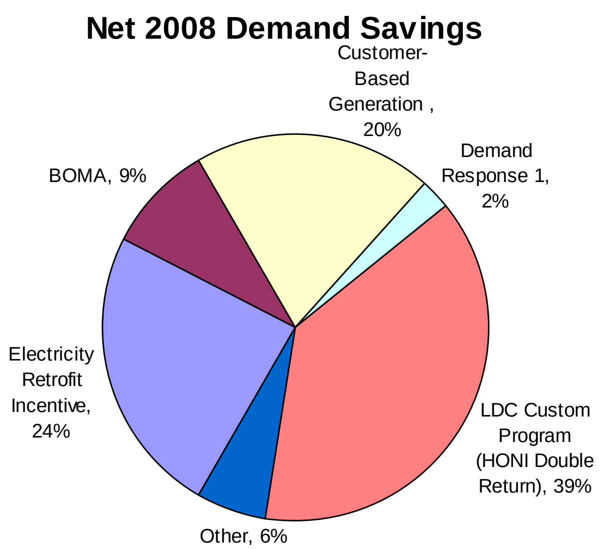
Business Program

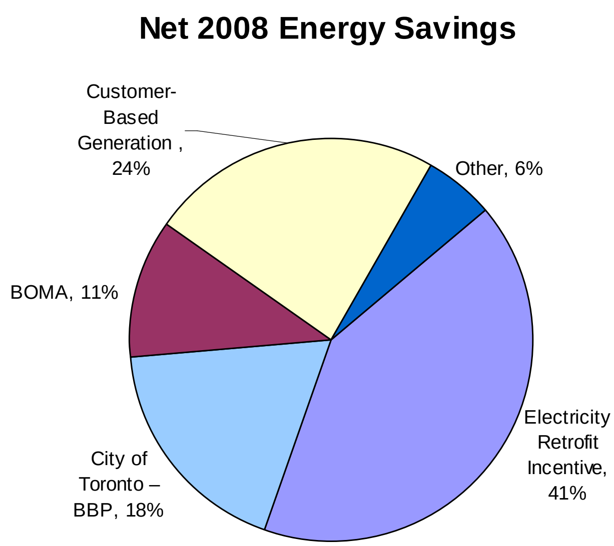
The business program achieved approximately 35 percent of forecasted net demand savings despite facing a number of significant challenges (described below). Figure 6 shows the breakdown of 2008 business program savings by major initiative.

Table 5: 2008 Business Program Final Results: Forecast vs. Actual

Metric	Forecast	Actual
Net peak-demand reduction (MW)	119	41
Net 2008 energy savings (GWh)	78	121
Net lifetime energy savings (GWh)	229	2,040

Figure 6: Breakdown of 2008 Business Program Savings by Major Initiative





A number of factors contributed to the lower-than-anticipated savings in the business program in 2008, including delays in the launch of some initiatives, program delivery challenges and the start of the economic downturn in mid-2008. Additionally, there were lower-than-expected savings per project for many initiatives, due to a preponderance of lighting measures versus other measures that offer substantial peak-demand savings and lifetime energy savings, such as motors and HVAC systems. Allowing for these factors, the program has had good initial success and is well-positioned to deliver substantial demand and energy savings over the next few years. A comprehensive evaluation was undertaken on the business program's major retrofit initiatives in 2008. As was done with the consumer program initiatives after their initial evaluations in 2007, the OPA is currently assessing how to adjust the design and delivery of these initiatives to improve and accelerate the performance of the business program.

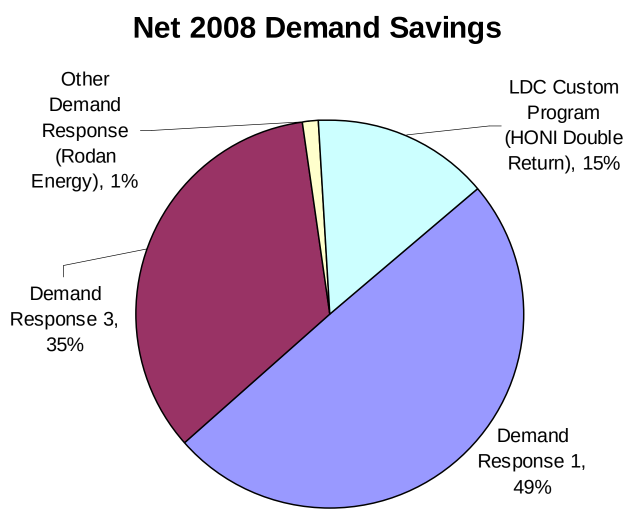
Industrial Program

The industrial program performed very well in 2008, achieving more than 200 percent of forecasted demand savings. The 2008 industrial program was comprised solely of demand response and generation initiatives, whose primary focus was in reduced electricity demand rather than energy savings through conservation. As such, energy savings were not forecasted or evaluated for demand response initiatives. There is significant potential, however, for energy savings in the industrial sector through process improvements such as productivity and product quality, and through equipment improvements such as rightsizing equipment, replacing inefficient equipment and operating equipment more effectively. The OPA is actively working with industry partners, LDCs and the government on a strategy and initiatives to harness this conservation potential.

Table 6: 2008 Industrial Program Final Results: Forecast vs. Actual

Metric	Forecast	Actual
Net peak-demand reduction (MW)	109	245

Figure 7: Breakdown of 2008 Industrial Program Savings by Major Initiative



Going forward, Demand Response 1 (DR1) will be structured as a stepping stone to other, firmly contracted, demand response initiatives and will be positioned as a way for prospective companies to experiment with the concept of demand response. It is proposed that rules will be implemented in DR1 to limit the period of enrollment available and perhaps require a minimum number of activations as an encouragement to experiment and prepare for other demand response programs.

As for Demand Response 3 (DR3), the OPA will undertake a review of its program structure in 2010 to facilitate a higher level of participation and ensure the program aligns with the future needs of the electricity system.

Supporting Initiatives

The OPA undertakes a number of initiatives to support the effectiveness of its consumer, business and industrial conservation programs and to help move Ontario towards a culture of conservation. Key supporting initiatives include:

- **conservation awareness activities** to help raise Ontarians' understanding of the need and ways to conserve energy
- **market research** to help the OPA to better target, deliver and track the impacts of its conservation programs
- **education and training activities** to help build the capability of Ontario's workforce to design and deliver conservation programs
- the **Conservation Fund and Technology Development Fund** to support new and innovative conservation programs and technologies.

Conservation Awareness

The OPA uses consistent messaging and branding to support all conservation programs as well as the development of a conservation culture throughout Ontario. In 2008, the OPA re-launched its Every Kilowatt Counts website, www.everykilowattcounts.ca, to provide broader and more in-depth conservation information for Ontarians. The site includes a special interactive, educational section for children called Kids' Corner, which also has resources that educators can download to supplement their energy conservation curricula. The website offers comprehensive information and case studies for all business sectors, including commercial, institutional, industrial and agricultural.

First annual Energy Conservation Week

The OPA promoted Ontario's first annual Energy Conservation Week, May 25 to May 31, 2008. Using a grassroots approach, the campaign encouraged wise electricity use by all Ontarians and was supported by the OPA website: www.energyconservationweek.ca. Individuals and organizations were encouraged to contribute to the site with their own Energy Conservation Week activities and testimonials.

A June 2008 Ipsos Reid poll indicated that 73 percent of Ontarians were aware of Energy Conservation Week. Fifty percent participated by engaging in an energy conservation activity during the week, with 74 percent of those participating at home, seven percent participating at work and 19 percent participating at both home and at work.

Second annual Conservation Awareness Day at Rogers Centre

The OPA hosted Conservation Awareness Day at the Toronto Blue Jays game on Sunday, May 25, 2008. The game was attended by more than 29,000 spectators and featured an on-field Certificate of Recognition presentation to Toronto Blue Jays president and CEO Paul Godfrey for energy conservation measures installed at Rogers Centre. The first 10,000 fans who entered the stadium received environmentally friendly Every Kilowatt Counts tote bags, and the first 15,000 fans who left the stadium received "Use Electricity Wisely" wheels.

The Great Refrigerator Roundup 100,000th fridge pickup media event

On November 13, 2008, the Great Refrigerator Roundup marked the decommissioning of the 100,000th refrigerator. This milestone event was celebrated at the ARCA decommissioning facility in Oakville with the Honourable George Smitherman, Deputy Premier and Minister of Energy and Infrastructure, members of the media, representatives form ARCA Inc, LDCs and the OPA, officials and the customer who owned the 100,000th fridge.

"This is a great example of how conservation adds up for Ontarians," said Minister Smitherman in the media release issued for this event. "With the removal of these fridges, enough energy has been saved to power about 3,000 homes, nearly 100 new green-collar jobs have been created and consumers collectively have saved about $3.5 million in energy costs in just one year."

OPA province-wide seasonal greeting card contest

In September 2008, the OPA, with assistance from Paton Publishing, Canada's largest youth magazine publisher, reached out to over 7,000 Ontario teachers and their students in grades four to six. Students were invited to submit an original coloured drawing with a seasonal theme that reflects either electricity efficiency or generation. More than 1,100 submissions from 74 schools across Ontario were received for the contest, illustrating awareness of the wise use of electricity. The winner, a student from St. Teresa of Avila Catholic School in Mississauga, received a commemorative trophy, a $200 honorarium and had her design used for the OPA's 2008 seasonal greeting card. The school was awarded a commemorative trophy and the grand prize of a 64" SMART interactive white board for use in the classroom. The top 14 creative submissions were displayed at The Children's Museum in Kitchener, Ontario.

Market Research

The OPA's market research initiative in 2008 had three main purposes: to inform its strategy to design and deliver the consumer and business programs, to monitor feedback on its residential initiatives and to inform the development of Every Kilowatt Counts as the umbrella brand for its conservation programs.

Market research results from 2008 indicate that Ontarians feel increasingly empowered about conserving electricity. Individuals are learning more about what they can do to use electricity more efficiently, and most of those surveyed report having taken some action to conserve electricity in the home.

Roughly two-thirds of survey participants, slightly more than 2007, believe they can definitely make a contribution to reducing total electricity use in the province. An overwhelming 85 percent reported that using electricity wisely in the home has become more of a personal priority than it was in 2007. Since 2007, progressively more Ontarians cite cost savings and reducing environmental impacts as the main drivers for their electricity conservation behaviours.

Conservation Fund

The Conservation Fund provides support for new and innovative electricity conservation initiatives that build the ability of Ontario's residents, businesses and institutions to reduce their demand for electricity. These initiatives help lay the groundwork for the success of future conservation efforts by testing new program approaches and investing in market and labour force development that supports conservation action over the longer term.

The Conservation Fund supports projects developed by entities such as industry associations, public sector organizations, non-profit organizations and consulting companies serving the commercial, institutional, residential or industrial sectors.

Table 7: 2008 Conservation Fund – Project Funding

Project Sector	# of Projects	OPA Funding ($)	Total Project Cost ($)
Residential	5	972,800	2,406,731
Commercial	4	727,700	1,456,600
Institutional	3	615,500	1,358,000
Industrial	3	684,000	1,572,000
Total	**15**	**3,000,000**	**6,793,331**

In 2008, the Conservation Fund invested $3 million in 15 initiatives, such as:

- centralized incentive program application and administration in the education sector
- upstream program model development for ENERGY STAR® qualified television set-top boxes
- conservation education as a measurable resource in social housing
- energy management in industrial food and beverage operations
- residential shade-tree program delivery model development
- post-secondary training and education in conservation-related fields
- secondary school co-operative education in conservation-related fields.

Several projects were completed in 2008. Results of note include:

- the deployment of an energy conservation secretariat to assist Ontario's 24 publicly funded colleges in managing energy demand and planning for energy-efficiency retrofits
- the incubation of a direct install program that led to the development of the OPA's Power Savings Blitz initiative
- the development of a training program and web-based resources for contractors to drive client demand for energy-efficient building retrofits.

In all three cases, Conservation Fund investments have led to ongoing initiatives that continue to directly or indirectly obtain conservation savings in Ontario. These projects serve as a model to other interested parties and provide a base on which to build.

More information is available on the Conservation Fund website, www.powerauthority.on.ca/cfund.

Technology Development Fund

The Technology Development Fund promotes the development and commercialization of technologies or applications that have potential to improve electricity supply, conservation or demand management. Technology development is an essential part of market transformation because it accelerates the diffusion of new, more efficient technologies into the economy, thereby helping homes and businesses do more with less.

The Technology Development Fund has sharpened its focus on three priority end-uses:

- high-efficiency lighting
- advanced and integrated controls
- advanced cooling and refrigeration.

Focusing in these areas will help to accelerate the achievement of Ontario's conservation targets because they deal with end-uses such as cooling and lighting, which contribute most significantly to high demand.

The OPA collaborates with the Ontario Centres of Excellence – Centre for Energy, and the Centre for Energy Advancement through Technological Innovation, organizations with significant electricity sector and technology expertise. These centres help to share the risk inherent in the development of emerging technologies. Together with its internally managed projects, the Technology Development Fund's contributions have leveraged over $36 million in external contributions – a ratio of more than 11 to one.

Table 8: 2008 Technology Development Fund – Project Funding

Project Type	# of Projects	OPA Funding ($)	Total Project Cost ($)
Conservation	7	1,064,000	11,504,542
Other	4	865,000	13,155,444
Total	**11**	**1,929,000**	**24,659,986**

In 2008, the Technology Development Fund invested just over $1.9 million in 11 projects involving the following innovative technologies and approaches:

- effective exterior solar shadings for residential windows
- energy hub management system for controlling energy use and generation in buildings and communities
- self-managing peak-demand management and response technology demonstration
- performance testing of high energy-efficiency ratio (EER) air conditioning units against the current technology (SEER)
- low-cost, high-performance thin-film photovoltaic solar cells

More information is available at the Technology Development Fund website, www.powerauthority.on.ca/tdfund.

Appendix A – 2008 evaluation summary

Table 9: 2008 OPA Conservation Portfolio Evaluations Summary

Initiatives	Consumer Program	Low-Income Consumer Program	Business Program	Industrial Program	New in 2008	2008 Activities Evaluated
Great Refrigerator Roundup	✓					✓
Cool Savings Rebate	✓					✓
Every Kilowatt Counts Power Savings Event	✓					✓
Summer Sweepstakes	✓				✓	✓
Aboriginal Retrofit Pilot[7]	✓					
Toronto Hydro – Mass-Market Initiatives	✓					
Toronto Hydro – Low-Income Initiatives		✓				
peaksaver®	✓		✓			✓
Electricity Retrofit Incentive	✓		✓			✓
City of Toronto – Better Buildings Partnership	✓		✓			✓
City of Toronto – New Construction			✓			
Toronto Hydro Business Incentive Program			✓			✓
BOMA Toronto			✓			✓
High Performance New Construction			✓		✓	
Power Savings Blitz			✓		✓	✓
LDC Custom Initiatives (Hydro One Double Return)			✓	✓	✓	✓
Demand Response 1 (DR1)			✓	✓		✓
Demand Response 3 (DR3)			✓	✓	✓	✓
Other Demand Response			✓	✓		✓
Customer-Based Generation	✓		✓	✓		

[7] Preliminary results for the 2008 Aboriginal Retrofit Pilot were not available as of publication date and will be reported in the OPA's 2009 Final Conservation Results report.

Appendix B – Cost-Effectiveness Metrics

This appendix describes the metrics used to assess the cost-effectiveness of conservation resources. Two cost-effectiveness tests – the total resource cost (TRC) test and the program administrator cost (PAC) test – along with levelized delivery cost metrics, have been used to assess the portfolio's conservation resources.

A cost-effectiveness test is a benefit-cost analysis designed to evaluate benefits and costs of conservation efforts from a particular perspective (i.e., each cost-effectiveness test uses a unique combination of benefit and cost components to determine an overall net benefit).

The net benefit of each test may be expressed either in absolute terms, whereby the net benefit is the difference between the present value (PV) of both the benefits and the costs, or as a ratio, whereby the net benefit is the determined by dividing the present value of the benefits by the costs.[8] A positive net benefit in absolute terms or a net benefit ratio greater than 1.0 indicates that benefits exceed costs from the perspective of each particular cost-effectiveness test.

Total Resource Cost (TRC) Test

The TRC test measures the benefits and costs of conservation efforts from a societal perspective. This test is described by the following equation:

TRC Test Net Benefit ($) = PV Avoided Supply Cost – (PV Incremental Equipment Cost + PV Program Cost)

or (to determine net benefit as a ratio):

TRC Test (Ratio) = PV Avoided Supply Cost / (PV Incremental Equipment Cost + PV Program Cost)

Incentive costs are not included in the determination of the TRC net benefit because incentives are a transfer of funds from the program-sponsoring organization to participating customers and, consequently, do not directly enhance the aggregate net benefit from a societal perspective.

Program Administrator Cost (PAC) Test[9]

The PAC test measures the benefits and costs of conservation efforts from the perspective of the program administrator or utility. This test is described by the following equation:

PAC Test Net Benefit ($) = PV Avoided Supply Cost – (PV Incentive Cost + PV Program Cost)

or (to determine net benefit as a ratio):

PAC Test (Ratio) = PV Avoided Supply Cost / (PV Incentive Cost + PV Program Cost)

[8] Present value is determined by discounting future benefits and costs over a 20-year period that begins in 2008. A real discount rate of four percent is used to perform this analysis.
[9] Also known as the utility cost test

Levelized Conservation Delivery Cost

Levelized delivery costs reflect the combined program administration and incentive costs required to procure conservation resources, expressed on a levelized basis by spreading these costs either over lifetime energy savings (in this case expressed as $/MWh) or over lifetime peak-demand savings (in this case expressed as $/MW-yr).

Levelized delivery cost expressed in terms of $/MWh is described by the following equation:

Levelized delivery cost ($/MWh) = PV (Incentive Cost + Program Cost) / PV Lifetime MWh Savings

Levelized delivery cost expressed in terms of $/MW-yr is described by the following equation:

Levelized delivery cost ($/MW-yr) = PV (Incentive Cost + Program Cost) / PV Lifetime MW Savings

Levelized delivery cost provides a basis for comparing conservation resources with different cost and resource savings characteristics, and with supply options with different cost and energy output capabilities.

For additional information on cost-effectiveness tests and levelized delivery costs, please refer to the OPA's EM&V Cost-Effectiveness Test Guide.[10]

[10] The OPA EM&V Cost-Effectiveness Test Guide can be found at: http://www.powerauthority.on.ca/Page.asp?PageID=1224&SiteNodeID=404.

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Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #12 List 1

Interrogatory

Issue 2.1: **Is the load forecast and methodology appropriate and have the impacts of Conservation and Demand Management initiatives been suitably reflected?**

Reference: Exhibit A, Tab 12, Schedule 3, pages 13-15 and page 19

a) Please outline what historical years' data are used by each of the three load forecasting models.
b) How does Hydro One Networks ensure that the impact of self-generation and CDM undertaken in these years is not "double-counted" by its subsequent adjustments as shown in Table 3?
c) Please provide the load forecasts for 2009, 2010 and 2011 produced in September 2009 by each of the three forecasting models.
d) What is the basis for the incremental embedded generation shown in Table 3 for 2009-2012?

Response

a) The monthly econometric model uses load data from 1971 to 2010. For the annual econometric models, the residential, commercial and industrial models use load data from the mid 1960's to 2007. The transportation model uses load data from 1982 to 2007, while the agricultural model uses load data from 1991 to 2007. For the end-use models, 2007 load data was used as the base year for the forecast.

b) As documented in lines 11-13 on page 9, lines 1-2 and lines 14-16 on page 14, lines 8-9 on page 15, the impact of embedded generation and CDM is added back to the historical data for modeling and then deducted from the forecast. This step ensures there is no double counting.

c) The September 2009 forecasts before the impact of embedded generation and CDM are presented in the following table.

Comparison of Forecasts of Load Growth (%)

	Econometric Model		End-Use Model	Final Forecast
Year	**Monthly**	**Annual**		
2009	-4.72	-5.41	-4.90	-4.72
2010	0.19	0.38	0.40	0.40
2011	n/a	1.06	0.70	1.06
2012	n/a	1.45	1.15	1.45
Sum of Growth Rates				
2009-2010	-4.53	-5.03	-4.50	-4.32
2009-2011		-3.97	-3.80	-3.26
2009-2012		-2.52	-2.65	-1.81

d) The incremental embedded generations shown in Table 3 are calculated based on the connection applications received by Hydro One and the OPA.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #13 List 1

Interrogatory

Issue 2.1: **Is the load forecast and methodology appropriate and have the impacts of Conservation and Demand Management initiatives been suitably reflected?**

References: i) EB-2008-0272, Exhibit I/Tab 6/Schedules 17 and 18
ii) Exhibit A, Tab 12, Schedule 3, Appendix 4

a) Please provide the forecast data for 2010 and 2011 consistent with the historical data set out in Reference (ii).
b) Please update the response to VECC IR #17 to include actual data for 2008 and 2009 and revised forecast data for 2010 to 2011.
c) With respect to part (b), please also provide a schedule that sets out, for 2009 by month, the day and time (hour) of the peak for Ontario overall and for each region.

Response

a) The requested information is provided below.

Forecast of Ontario Demand and Hydro One Charge Determinats
(MW)

Charge Determinant	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2010												
Ontario Demand	22,211	21,968	20,836	18,349	18,222	21,648	23,056	22,401	21,002	18,969	20,416	21,617
Network Connection	21,711	21,464	20,364	17,922	17,799	21,155	22,532	21,891	20,520	18,529	19,947	21,129
Line Connection	20,906	20,672	19,627	17,309	17,192	20,378	21,685	21,077	19,775	17,885	19,231	20,354
Transformation Connection	18,065	17,861	16,959	14,954	14,853	17,607	18,737	18,211	17,086	15,452	16,615	17,588
2011												
Ontario Demand	21,836	21,708	20,501	18,169	17,902	21,371	22,740	22,123	20,769	18,788	20,180	21,273
Network Connection	21,355	21,218	20,045	17,751	17,494	20,892	22,232	21,626	20,299	18,357	19,722	20,803
Line Connection	20,644	20,514	19,400	17,223	16,979	20,205	21,477	20,902	19,641	17,798	19,094	20,120
Transformation Connection	17,841	17,726	16,765	14,881	14,671	17,459	18,559	18,062	16,972	15,378	16,499	17,388

Note. All figures are weather-normal.

b) Actual data for 2008 and 2009 and revised forecast for 2010 to 2011 are presented below.

Peak-Load by Region
(MW)

Year	Region	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2008	Central	11,260	11,301	10,293	9,600	9,517	12,572	12,358	11,739	11,797	9,651	10,380	10,898
	East	3,487	3,447	3,062	2,701	2,375	3,238	3,183	2,964	3,128	2,807	3,035	3,501
	Northeast	1,305	1,299	1,203	1,174	1,020	1,013	1,043	1,058	1,067	1,022	1,216	1,339
	Northwest	735	759	716	681	718	641	621	638	657	648	647	745
	Southwest	5,066	5,069	4,661	4,317	4,190	5,710	5,722	5,484	5,535	4,422	4,668	4,935
2009	Central	11,117	10,945	10,608	9,457	9,057	11,669	10,422	12,682	10,349	9,377	9,880	10,826
	East	3,642	3,378	3,254	2,698	2,356	3,073	2,825	3,385	2,677	2,625	2,980	3,471
	Northeast	1,367	1,337	1,217	1,058	845	828	843	922	861	956	1,011	1,194
	Northwest	755	593	602	594	578	550	495	487	430	437	500	547
	Southwest	4,905	4,759	4,740	4,109	3,891	5,242	4,653	5,621	4,586	4,145	4,425	4,843

Peak-Load by Region Consistent with Total System Peak
(MW)

Year	Region	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2008	Central	11,739	11,910	10,838	10,140	9,960	13,126	12,821	12,181	12,218	10,076	11,074	11,470
	East	3,635	3,633	3,224	2,853	2,486	3,381	3,303	3,075	3,239	2,931	3,238	3,685
	Northeast	1,360	1,369	1,267	1,240	1,068	1,058	1,082	1,098	1,105	1,067	1,297	1,409
	Northwest	767	800	754	720	751	669	644	662	681	677	690	784
	Southwest	5,281	5,342	4,907	4,560	4,385	5,961	5,937	5,691	5,732	4,616	4,980	5,194
2009	Central	11,728	11,517	11,151	9,894	9,508	12,312	10,841	13,387	10,802	9,847	10,361	11,365
	East	3,842	3,555	3,420	2,823	2,473	3,243	2,938	3,573	2,795	2,756	3,124	3,644
	Northeast	1,443	1,406	1,280	1,107	888	873	876	973	898	1,004	1,060	1,254
	Northwest	796	624	632	622	607	580	515	514	448	459	525	575
	Southwest	5,175	5,008	4,983	4,298	4,085	5,531	4,840	5,934	4,787	4,353	4,640	5,084

Peak-Load Forecast by Region
(MW)

Year	Region	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2010	Central	11,088	11,177	10,441	10,246	9,099	12,230	12,513	11,028	10,148	9,707	10,202	10,882
	East	3,640	3,450	3,241	2,747	2,381	3,162	2,996	2,895	2,685	2,754	3,106	3,393
	Northeast	1,122	1,078	1,047	956	850	844	875	836	866	879	1,009	1,010
	Northwest	688	690	642	610	562	558	571	562	574	596	588	624
	Southwest	4,968	4,920	4,604	4,647	4,126	5,451	5,394	4,820	4,555	4,661	4,592	4,794
2011	Central	10,953	11,041	10,315	10,122	8,988	12,082	12,362	10,895	10,025	9,589	10,078	10,750
	East	3,577	3,390	3,185	2,699	2,340	3,107	2,944	2,845	2,639	2,707	3,052	3,334
	Northeast	1,103	1,060	1,029	940	836	829	860	822	852	864	991	993
	Northwest	678	680	633	602	554	550	563	555	566	587	580	616
	Southwest	4,906	4,858	4,547	4,588	4,074	5,382	5,326	4,759	4,498	4,602	4,534	4,734

Peak-Load Forecast by Region Consistent with Total System Peak
(MW)

Year	Region	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2010	Central	11,451	11,519	10,891	9,789	9,743	11,902	12,909	12,265	11,320	9,901	10,683	11,362
	East	3,759	3,556	3,381	2,624	2,549	3,077	3,091	3,220	2,995	2,810	3,252	3,542
	Northeast	1,159	1,111	1,092	913	910	821	902	930	966	896	1,056	1,055
	Northwest	711	711	670	583	601	543	589	625	640	608	616	652
	Southwest	5,131	5,071	4,803	4,439	4,418	5,304	5,564	5,360	5,081	4,754	4,809	5,006
2011	Central	11,273	11,397	10,730	9,704	9,583	11,763	12,745	12,126	11,207	9,819	10,573	11,195
	East	3,681	3,499	3,313	2,588	2,494	3,025	3,036	3,167	2,950	2,772	3,202	3,472
	Northeast	1,135	1,094	1,070	901	891	807	886	915	952	884	1,040	1,034
	Northwest	698	702	659	577	590	536	581	617	633	601	608	641
	Southwest	5,049	5,015	4,729	4,399	4,344	5,240	5,492	5,298	5,028	4,712	4,757	4,930

c) The peak dates for 2009 are presented in the following table:

Month	Date	Region					
		Central	East	Northeast	Northwest	Southwest	Ontario
Jan	Day	14	15	16	13	15	15
	Hour	19	19	11	23	19	19
Feb	Day	4	5	3	18	4	4
	Hour	19	19	20	22	19	19
Mar	Day	2	2	12	19	2	2
	Hour	20	19	7	23	20	20
Apr	Day	6	6	7	10	7	7
	Hour	12	17	21	7	10	20
May	Day	21	19	22	3	28	21
	Hour	16	17	11	21	13	13
Jun	Day	24	25	24	2	24	24
	Hour	16	16	22	6	16	16
Jul	Day	28	28	22	14	28	28
	Hour	17	17	21	18	17	17
Aug	Day	17	17	17	11	17	17
	Hour	13	15	21	16	13	14
Sep	Day	8	8	11	26	9	8
	Hour	16	17	21	13	16	16
Oct	Day	15	28	22	22	15	15
	Hour	19	18	19	21	19	19
Nov	Day	30	30	30	29	30	30
	Hour	18	18	21	18	18	18
Dec	Day	16	17	16	15	10	17
	Hour	18	18	20	21	18	18

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #14 List 1

Interrogatory

Issue 2.2: Are Other Revenue (including export revenue) forecasts appropriate?

Reference: Exhibit H1, Tab 5, Schedule 1
Preamble: It is anticipated that the following questions may be addressed by the IESO.

a) Please provide a schedule that, for the years 2007-2009 and for January to June 2010, sets out the monthly volumes of exports from Ontario. Note: Please clarify the point of "measurement" for export volumes.
b) With respect to part (a) please also provide the following additional details:
   - Breakdown the monthly values as between peak and off-peak. Use the definition of peak and off-peak consistent with that in the IESO's ETS study and confirm what the definition is.
   - For each time period, provide a breakdown of the volumes by source and sink for the exports (e.g., Ontario -> MISO; MISO -> NYISO (i.e. linked wheel), etc.).

Response

This response is provided by the IESO.

a) and b) The information requested is provided in Attachment 1 to this interrogatory response.

Ontario Monthly Export Volumes (MWh)

Year	Month	NEW YORK		MINNESOTA		MISO		MANITOBA		QUEBEC	
		OFF PEAK	PEAK	OFF PEAK	PEAK	OFF PEAK	PEAK	OFF PEAK	PEAK	OFF PEAK	PEAK
2007	1	324,358	219,240	1,580	5,059	20,422	42,962	15,231	22,550	52,076	48,602
2007	2	473,464	392,095	3,877	3,818	81,811	99,657	25,339	14,128	45,010	40,353
2007	3	445,588	212,290	1,014	3,458	38,222	63,482	19,129	11,716	55,027	41,086
2007	4	402,045	216,815	6,630	10,545	115,684	251,761	26,896	15,779	46,529	31,919
2007	5	323,598	192,503	9,575	11,991	142,090	261,059	1,656	3,850	54,662	38,247
2007	6	534,088	201,373	5,459	11,847	62,503	103,094	666	684	39,019	20,077
2007	7	561,655	379,808	16,154	15,919	72,769	129,502	162	315	39,502	20,875
2007	8	520,592	211,704	14,995	27,190	50,741	193,270	1,648	346	50,953	27,428
2007	9	453,670	230,628	4,040	5,501	18,859	52,482	767	531	62,888	33,194
2007	10	417,698	272,171	2,549	2,677	69,038	71,758	899	181	27,633	19,863
2007	11	473,362	278,708	10,345	21,903	30,116	49,780	443	1,457	41,659	25,083
2007	12	466,139	450,470	28,358	30,446	121,903	100,682	8,810	8,017	56,618	34,957
2008	1	528,794	634,071	31,574	30,146	356,296	327,310	8,311	11,359	51,920	41,423
2008	2	408,374	376,895	16,006	18,101	323,940	353,348	3,520	5,135	40,219	26,983
2008	3	542,119	327,035	21,028	28,172	420,295	381,577	8,003	7,635	46,147	33,176
2008	4	574,334	531,654	23,133	35,803	548,486	573,323	3,746	5,024	43,456	32,610
2008	5	484,138	402,199	24,369	37,811	768,331	795,733	0	0	55,305	45,432
2008	6	546,434	464,740	25,489	33,958	654,301	640,609	0	0	51,624	33,147
2008	7	481,583	619,446	35,233	42,837	549,784	567,828	0	0	44,654	31,032
2008	8	320,346	310,451	38,926	43,401	445,574	395,800	136	60	47,757	28,568
2008	9	340,341	248,619	20,836	33,563	288,012	228,702	1,066	1,532	49,791	33,422
2008	10	344,814	411,986	25,063	35,471	288,337	228,769	863	667	50,970	35,270
2008	11	371,211	288,986	26,519	21,203	309,256	190,417	8,166	1,260	51,935	34,478
2008	12	319,243	297,461	20,415	21,598	276,801	305,376	24,815	35,518	44,577	35,939
2009	1	501,767	386,550	3,213	7,780	413,811	376,930	3,173	18,926	31,180	24,457
2009	2	328,028	178,527	9,940	8,682	396,815	341,065	2,788	3,355	11,879	4,489
2009	3	167,232	89,705	29,045	31,908	578,094	486,437	16,777	11,626	16,095	5,006
2009	4	103,571	40,661	16,789	24,975	313,012	239,975	5,940	4,866	8,376	5,995
2009	5	204,423	86,120	23,264	35,047	354,593	288,058	4,592	4,172	9,257	11,416
2009	6	208,590	117,298	19,566	45,695	464,136	523,675	8,899	5,472	12,821	4,519
2009	7	212,774	162,585	27,787	38,631	529,895	510,747	2,053	3,978	75,595	10,422
2009	8	311,565	158,870	25,002	36,259	437,713	433,888	3,547	1,783	75,199	15,081
2009	9	260,686	96,321	25,185	26,403	330,823	389,507	2,797	1,311	36,366	6,272
2009	10	174,148	106,551	21,966	24,385	297,107	270,432	3,328	2,293	1,893	580
2009	11	122,545	37,447	8,036	9,843	249,189	222,543	19,640	21,512	135,308	68,958
2009	12	141,847	82,580	15,684	25,659	177,690	291,590	17,359	23,073	415,437	186,913
2010	1	222,122	118,114	22,246	31,693	413,865	443,289	30,638	25,501	85,683	56,755
2010	2	73,227	44,023	10,077	21,905	381,784	557,613	6,166	9,687	58,868	43,547
2010	3	120,148	50,198	5,582	20,938	399,091	538,907	2,846	10,047	72,391	37,076
2010	4	154,697	109,404	5,778	9,354	154,440	270,915	7,572	15,802	51,193	6,550
2010	5	72,461	64,214	3,628	9,999	151,234	198,229	2,894	3,670	29,172	3,010
2010	6	70,975	58,835	3,727	11,197	316,699	445,698	2,149	2,816	189,929	43,929

Monthly Linked Transactions (MWh)

Year	Month	FROM MISO TO NEW YORK	FROM NEW YORK TO MISO	FROM NEW YORK TO PJM	FROM PJM TO MISO	FROM QUEBEC TO MISO	FROM QUEBEC TO NYIS	FROM NEW ENGLAND TO MISO
2007	1	414	100					
2007	2	500			6,237			
2007	3	1,261	485					
2007	4	750	1,071					
2007	5	689	3,878					0
2007	6	1,170	1,519		2,302	4,642		2,346
2007	7	1,879	900	1,821	14,392	6,667		
2007	8	2,574	3,830	11,458	8,866	6,181		
2007	9	4,555		2,020	2,120			
2007	10	3,334	360	2,480				
2007	11	7,330	75	1,280	1,468			
2007	12	5,166	0	7,505	13,831			
2008	1	900	559	273,477	21,047	150		
2008	2	1,141		132,750	33,725			
2008	3	1,000	200	569,214	9,292	59,893	31,063	
2008	4	1,190		571,978	27,157	40,057	32,584	
2008	5	485		1,018,280	69,811	8,143		
2008	6	391	100	803,367	84,411	48,739	200	
2008	7	525	3,360	547,955	55,738	81,212		462
2008	8		10,394			72,011		700
2008	9	100	2,561			7,687		
2008	10	75	1,127			1,045		
2008	11	380	123			433		
2008	12	414	1,407			600		
2009	1	1,971						
2009	2	1,329	100					
2009	3		7,472					
2009	4							
2009	5		25,433					
2009	6		3,047			4,987		
2009	7		825			2,253		
2009	8	205	23,034			22,861	2,338	
2009	9	75	31,184			24,206	1,280	
2009	10	250	11,267			2,003		
2009	11					150		
2009	12	75	0			6,946		
2010	1	100	2,588			63,722	500	
2010	2		6,819			69,060		
2010	3		20,922			68,425		
2010	4	150	1,228			200		
2010	5	347				0		
2010	6	200	7,186			44,440		

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #15 List 1

Interrogatory

Issue 2.2: Are Other Revenue (including export revenue) forecasts appropriate?

References: i) Exhibit H1, Tab 5, Schedule 2, page 4
ii) Exhibit H1, Tab 5, Schedule 2, Attachment 1, pages 7 & 9

Preamble: It is anticipated that the following questions will be addressed by the IESO.

a) Please indicate which "neighbours" the IESO held discussions with regarding the elimination of all ETS tariffs.
b) Please clarify whether the "discussions" were with respect to the reciprocal elimination of the Transmission Service charges or both the Transmission Service Charges and Other Charges – as set out in Table 1 (page 7) of Reference (ii).
c) With respect to Table 1, please clarify that the Transmission Service and Other Charges are charges levied by the "source". In each case, are there any "charges" levied by the "sink" jurisdiction?
d) With respect to Table 1, please indicate what the "Other Charges" levied by each jurisdiction (including the IESO) are for.
e) What is the IESO's understanding as to why jurisdictions (other than New York) did not consider reciprocal elimination of transmission tariffs as being a "priority" at that time (Reference (i) – page 4)?
f) What is the current status of the IESO's discussions with New York on this issue?
g) When does the IESO expect to be able to "engage in meaningful discussions with our neighbours" on this issue (Reference (ii) – page 9)?
h) Please discuss the incentive there is for neighbours such as MISO to engage in such discussions when they currently only face an ETS of $1/MWH in Ontario but receive more than four time this for exports to Ontario (Reference (i) – page 7).

Response

This response is provided by the IESO.

a) Please see Exhibit I, Tab 9, Schedule 3.

b) The discussions were limited to reciprocal elimination of the export tariff.

c) Yes, the charges are administered at the source. Hydro Quebec Trans-Energie also levies transmission service and ancillary services charges, as well as charge to account for losses on transaction sinking in Quebec.

d) The purpose and amount of the charges comprising “Other Charges” varies by jurisdiction; however, in general these charges relate to provision of ancillary services, transmission losses and other applicable costs associated with administering the transaction.

e) Please see Exhibit I, Tab 9, Schedule 3 regarding Hydro Quebec Trans-Energie. The IESO does not know why MISO did not consider this matter a priority.

f) Please see Exhibit I, Tab 9, Schedule 3.

g) Please see Exhibit I, Tab 9, Schedule 3.

h) The IESO does not know what MISO views as an incentive (or lack of an incentive) to have such discussions.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #16 List 1

Interrogatory

Issue 2.2: Are Other Revenue (including export revenue) forecasts appropriate?

Reference: Exhibit H1, Tab 5, Schedule 1, Attachment 1 page 9
Preamble: It is anticipated that the following questions will be addressed by the IESO.

a) Please confirm that the results of the quantitative and qualitative analysis undertaken as part of the ETS Tariff Study indicated that a tariff based on Average Embedded Network Transmission cost was the option that best satisfied the established selection principles. If not, please reconcile response with first paragraph on page 9.
b) Please confirm that the IESO's recommendation to retain the $1/MWH ETS tariff was based on changing conditions that led to concerns regarding i) increased surplus base load generation and ii) increased volatility in the supply/demand balance and the view that the higher level of exports associated with the $1/MWh tariff would help mitigate these concerns.
c) If there are any other issues (besides those articulated in part (b)) that maintaining a lower export tariff is meant to address please describe what they are and how a lower export tariff/higher export levels serve to address the concerns.
d) Please indicate when the IESO first became aware of the each of the following changing conditions:
    - Load deterioration due to economic conditions
    - Legislative changes through the GEGEA
    - Increase occurrence of base load generation
e) Why was the consultant not requested to update the analysis of the study to reflect these emerging conditions?

Response

This response is provided by the IESO.

a) b) c) d) The IESO initiated SE-78 in December 2008 to consider and study an appropriate ETS tariff base on the three options identified in HONI's 2007 rate application. The scope of the study was later expanded to consider a fourth option and to address potential SBG issues identified by some stakeholders. Charles River and Associates (CRA) was retained to undertake the study.

The CRA study was completed in August 2009. Based on defined quantitative and qualitative metrics, IESO staff concluded that option 2 (i.e., a tariff based on average embedded network transmission costs) best met the selection criteria.

IESO management considered the CRA study along with other relevant factors, specifically: significant changes that the electricity system was undergoing as the result of the Green Energy and Green Economy Act (GEA) (i.e., substantial increases in intermittent/renewable generation); load deterioration and the prospects for future load recovery and, increased incidences of surplus base load generation (SBG). In August 2009, updated demand forecasts showed lower forecast demand than that relied upon in the CRA study. As well, there had been high incidences of SBG events in recent months (e.g., in April – August 2009, the IESO experienced 971, 274, 1,272, 606, and 457 hours respectively when nuclear generation or imports had to be constrained due to surplus conditions; as compared to less than 100 hours in 2008).

IESO management determined that there was a high degree of uncertainty relating to the foregoing factors and the associated consequences for operating the electricity system. IESO management also determined that the predicted benefits in switching to option 2 were relatively small as compared to overall Ontario transaction costs and that these benefits could decrease as the result of changing system conditions. As a result, the IESO decided that it would be prudent to recommend maintaining the $1/MWh ETS tariff (and thereby not do anything to dampen exports) until further time elapsed and it was possible to more fully assess the consequences of the GEA and economic recovery.

e) See Exhibit I, Tab 4, Schedule 19, part (d).

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #17 List 1

Interrogatory

Issue 2.2: Are Other Revenue (including export revenue) forecasts appropriate?

Reference: i) Exhibit H1, Tab 5, Schedule 2, page 5
ii) Exhibit H1, Tab 5, Schedule 2, Attachment 1

Preamble: It is anticipated that the following questions may be addressed by the IESO.

a) The IESO claims that recent events have led to the view that there will be increased periods of surplus base load generation. Please provide a schedule that contrasts the amount and times of occurrence for surplus base load generation as identified in the ETS Study (assuming Status Quo ETS tariffs) for 2010 and 2015 with the IESO's current expectations for the same years.

b) With respect to the impact of different ETS tariffs on export volumes (Reference (ii) – page 16) did the consultant's model indicate how much of the impact was in the peak versus off-peak period for 2010 and 2015? If yes, please provide.

c) For each potential export path out of Ontario where exports have actually occurred between January 2007 and June 2010, please provide a schedule (and "live" data file) that sets out the following for each hour during this period:
   - The level of exports
   - The "cost" of the export power
   - The "price" received" for the export power from the sink.
   - Any other applicable hourly charges apart from the ETS tariff.
   - Indication if the hour is considered peak or off-peak
   - Indication if the hour was one with surplus base load generation.

d) Based on the data from part (c), how many MWhs of exports would be still be economic versus now uneconomic if the ETS Tariff was $5/MWh versus $1/MWh?

e) Based on the data from part (c), how many MWHs of exports during periods of surplus base load generation would be stlll be economic vs. now uneconomic if the ETS Tariff was $5/MWh versus $1/MWh?

f) As an alternative to simply maintaining the Status Quo, did the IESO consider addressing its concerns regarding increased surplus base load generation by means of an ETS tariff that would be based on $1/MWh in the off-peak and set based on the Average Embedded Network Transmission cost during the peak period?

- If not, please explain why not. Please also comment now on the merits of such an approach.
- If yes, please explain why this approach was rejected.

Response

This response is provided by the IESO.

a) The final results of the CRA study showed that there were no SBG events in 2010 and 2015 test years. The attached spreadsheet shows the actual SBG events that were observed in 2010 (Page 2 of 2). The IESO's forecast of expected SBG conditions is updated and published on a weekday basis. The spreadsheet also shows the IESO's latest forecast of expected SBG events over the forecast period (Page 1 of 2). Given the current SBG forecast horizon, the IESO doesn't have data on which to contrast the amount and time of expected surplus base-load generation conditions in 2015.

b) The CRA modeling showed the exports volumes for on and off peak for 2010 and 2015 under the Status Quo scenario. With respect to the impact of the other ETS tariff options on export volumes, the results of CRA's modeling did not indicate how much of the impact was in the peak versus off-peak hours in 2010 and 2015.

c) Please refer to the spreadsheets provided as Attachment 2 to this interrogatory (Hydro One will only be providing Attachment 2 in electronic form due to the size of the file.)

d) The results of the CRA study did not show how many MWHs of exports would still be economic vs. now uneconomic if the ETS Tariff was $5/MWh versus $1/MWh. The IESO has not asked CRA to do this further analysis.

e) The results of the CRA study did not show how many MWHs of exports during periods of surplus base load generation would be still be economic vs. now uneconomic if the ETS Tariff was $5/MWh versus $1/MWh. The IESO has not asked CRA to do this further analysis.

f) No, this alternative ETS Tariff option was not part of the scope of work that was established during the stakeholdering process.

Current Forecast of Surplus Baseload Generation (2010)

Date	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Thu Aug 12, 2010																								
Fri Aug 13, 2010																								
Sat Aug 14, 2010																								
Sun Aug 15, 2010			123	443	547	274																		
Mon Aug 16, 2010			156	119																				
Tue Aug 17, 2010	537	940	1348	1577	1167	456																		277
Wed Aug 18, 2010	1058	1307	1407	1529	1182	226																		
Thu Aug 19, 2010	391	883	1081	1034	685																			296
Fri Aug 20, 2010	1952	2227	2328	2449	1956	1286	325																407	1405
Sat Aug 21, 2010	2524	2889	3037	3230	3095	2796	2108	1488	329										316	232	341	929	1676	2382
Sun Aug 22, 2010	2390	2842	3117	3204	3147	3067	2772	2033	1264	724	323	225	213	313	410	227	57	224	407	27		502	1145	1746
Mon Aug 23, 2010	1957	2118	2226	2137	1899	655																	226	1102
Tue Aug 24, 2010	1450	1779	2076	2108	1621	573																		460
Wed Aug 25, 2010	752	1319	1635	1696	1294	482																		236
Thu Aug 26, 2010	2045	2628	2868	2872	2463	1717	289																	931
Fri Aug 27, 2010	1288	1746	2090	2143	1919	1411	318																368	1186
Sat Aug 28, 2010	2619	3099	3306	3389	3349	3018	2727	1819	778	138											108	899	1619	2363
Sun Aug 29, 2010	2116	2418	2560	2650	2666	2434	2193	1510	764	240				12	16							164	841	1542
Mon Aug 30, 2010	1330	1488	1590	1497	1262	17																		446
Tue Aug 31, 2010	457	1110	1440	1541	1224	505																		325
Wed Sep 01, 2010		322	867	1105	834	84																		
Thu Sep 02, 2010	176	592	868	918	577																			
Fri Sep 03, 2010	1609	1855	2065	2023	1497	316																	105	826
Sat Sep 04, 2010	2149	2473	2696	2833	2748	2324	1996	1068	161													462	1197	1947
Sun Sep 05, 2010	1958	2278	2409	2507	2568	2479	2209	1485	686	26													415	1019

2010 Observed Surplus Base-load Generation

Date	Hour	Amout (MW)
24-Mar	22	518
2-Apr	2	87
	3	76
	4	144
	23	1300
	24	300
3-Apr	1-10, 22-24	300
4-Apr	1-18	300
	24	525
5-Apr	1-8	525
	23	300
1-May	7	100
5-May	4	271
30-May	4	154
	5	300
	6	578
	7	430
	8	675
7-Jun	6	150
13-Jun	6	256
	7	230
20-Jun	7	340

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #18 List 1

Interrogatory

Issue 2.2: Are Other Revenue (including export revenue) forecasts appropriate?

Reference: i) Exhibit H1, Tab 5, Schedule 2, page 5
ii) Exhibit H1, Tab 5, Schedule 2, Attachment 1

Preamble: It is anticipated that the following questions will be addressed by the IESO.

a) Please explain how a higher level of exports (presumably due to lower ETS tariffs) will facilitate the management of the supply/demand balance in real time.
b) If not addressed in response to part (a), please describe (in lay terms) how exports are "scheduled" in the IESO market and the ability of the IESO to alter such schedules as forecast and real conditions on the system change.
c) Can the IESO "cut" an export in real time in response to variation (i.e. a decline) in real time output from renewable resources such as wind and solar?
d) Can additional exports be authorized in real time in response to variation (i.e., an increase) in real time output from renewable resources such as wind and solar?

Response

This response is provided by the IESO.

a) When baseload electricity production exceeds Ontario electricity demand in any given hour, this will lead to SBG events. A higher level of exports can help to mitigate/eliminate the SBG condition by using the excess energy in Ontario to meet demand in surrounding markets. More exports for example therefore can prevent nuclear baseload units from being dispatched down to lower production levels or in some cases more exports can prevent the shutdown of these units.

b) Market particpants who wish to export energy must make a bid to withdraw energy from the IESO-controlled grid. Inter-jurisdictional trade is co-ordinated between the IESO and other balancing authorities, using hourly interchange schedules. Exports are scheduled on an economic basis within the physical security limits of the intertie and of the IESO-controlled grid. Which exports are accepted for a particular dispatch hour is determined by the pre-dispatch run of the dispatch algorithm during the preceding hour (for example, the export schedule for noon to 1:00 p.m. is determined between 11:00 a.m. and noon). This schedule is then confirmed with our neighbouring jurisdictions to determine if matching transactions have been scheduled. Once this is confirmed, transactions become fixed for the dispatch hour. This means that they do not change during the hour (unless a change is needed for reliability reasons). Therefore, intertie transactions compete economically in pre-dispatch in order to be scheduled, but are then fixed for the hour in real-time. In other words, they are treated like a dispatchable facility in pre-dispatch, but like a non-dispatchable one in real-time.

c) The IESO may curtail an export transaction in real-time for reliability reasons. For example, if there is a sudden decline in wind and solar production in real-time and the IESO determines that this poses a reliability problem then the IESO may curtail an export transaction to manage that reliability issue. It is worthwhile noting that the IESO would normally try to maneuver all available internal generation to solve the reliability issue prior to curtailing an export transaction.

d) Export transactions are scheduled one hour ahead of real-time and they are fixed during the hour in real-time. The IESO cannot increase the export quantity in real-time even if there is more output from renewable resources such as wind and solar.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #19 List 1

Interrogatory

Issue 2.2: **Are Other Revenue (including export revenue) forecasts appropriate?**

Reference: i) Exhibit H1, Tab 5, Schedule 2, page 2
ii) Exhibit H1, Tab 5, Schedule 2, Attachment 1, page 4

Preamble: It is anticipated that the following questions may be addressed by the IESO.

a) When were the findings of the consultant's study and the view that Option 2 best satisfied the four selection principles first shared/reviewed with Stakeholders?
b) Was any analysis or further work undertaken to address stakeholder comments? If yes, please outline.
c) When was the IESO Management recommendation to remain with the $1/MWh ETS tariff first shared with Stakeholders?
d) Were the concerns of IESO Management regarding changing conditions shared with Stakeholders and Stakeholder input sought regarding the alternative means of addressing these concerns prior to the formulation of the IESO Management recommendation? If not why not? If yes, what input was received and provide any analysis undertaken/options considered in response to this input?
e) Please provide copies of any comments received regarding the IESO's Stakeholder Engagement Process on this issue.

Response

This response is provided by the IESO.

a) The study findings and IESO Staff's view that Option 2 best satisfied the four selection principles was reviewed with stakeholders on August 10, 2009.

b) Yes, additional work and analysis was carried out by IESO Staff in response to comments provided by stakeholders. Please refer to Export Transmission Service Tariff (SE-78) Stakeholder Feedback (Exhibit H1-5-2, Attachment 1, Appendix C).

c) IESO management's recommendation to maintain the $1/MWh ETS Tariff was communicated to stakeholders on August 27, 2009.

d) IESO management made its recommendation to maintain the $1/MWh ETS Tariff based on a number of factors, including the CRA study, prior feedback received from stakeholders as part of SE-78, IESO staff's recommendation and its views on economic conditions, GEGEA-related changes and SBG events. IESO management was satisfied that it had adequate information and it therefore did not seek additional stakeholder input prior to making its recommendation.

e) For written stakeholder comments regarding the IESO's stakeholder Engagement Process, please refer to Export Transmission Service Tariff (SE-78) Stakeholder Feedback (Exhibit H1-5-2, Attachment 1, Appendix C). Summary of stakeholder session feedback can be found at the following links:

i. **January 22, 2009 Stakeholder Session:**
http://www.ieso.ca/imoweb/pubs/consult/se78/se78-20090122-Summary_of_Session_Feedback.pdf

ii. **June 25, 2009 Stakeholder Session:**
http://www.ieso.ca/imoweb/pubs/consult/se78/se78-20090625-Summary_of_Session_Feedback.pdf

iii. **August 10, 2009 Stakeholder Session:**
http://www.ieso.ca/imoweb/pubs/consult/se78/se78-20090810-Summary_of_Session_Feedback.pdf

iv. **September 21, 2009 Final Stakeholder Evaluation (Updated)**
http://www.ieso.ca/imoweb/pubs/consult/se78/se78-20090923-Feedback_Summary_Final.pdf

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #20 List 1

Interrogatory

Issue 3.1: Are the proposed spending levels for, Sustaining, Development and Operations OM&A in 2011 and 2012 appropriate, including consideration of factors such as system reliability and asset condition?

Reference: Exhibit A/Tab 14/Schedule 1/Pages 5-6

Preamble: Hydro One Transmission also uses benchmarking (internal and external) and information on best practices to identify ways to operate more effectively and efficiently. Internal analyses are performed to compare performance across geographic regions and identify performance trends

a) Provide a copy of the latest Benchmarking study.
b) Update Hydro One's metrics in the benchmarking study for the historic years and Bridge year.
c) Provide a schedule that for the Asset Replacement metrics and those Cost Metrics that are expressed in percentage terms sets out the average (two-year) results for Hydro One Networks.

Response

a) See Exhibit I, Tab 1, Schedule 8 for key tables and relevant reports.

b) An update of Hydro One's metric in the benchmarking study for historic and bridge values are provided in the table below

Description	**Historic**			**Bridge**
	2006	**2007**	**2008**	**2009**
Transmission Line Capital Spending per Asset	2.33%	4.30%	4.10%	6.40%
Transmission Line O&M Expense per Circuit mile	$1449	$2002	$1801	$2126
Transmission Substation O&M Expense per Asset	2.73%	2.75%	2.37%	2.00%
Lost Time Incident Rate-Transmission and Distribution	0.37	0.36	0.30	0.27

c) The schedule for the Asset Replacement is not available for the First Quartile 2009 Community study. See Exhibit I, Tab 1, Schedule 8 for available Cost metrics

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #21 List 1

Interrogatory

Issue 3.1: Are the proposed spending levels for, Sustaining, Development and Operations OM&A in 2011 and 2012 appropriate, including consideration of factors such as system reliability and asset condition?

Reference: Exhibit A/Tab 14/Schedule 1/Page 12

Preamble: In 2009, Hydro One started to report *Transmission Unit Cost* defined as Capital and O&M Costs ($) per Asset Value ($) as an indicator of productivity using costs per unit in the Corporate Scorecard. Hydro One will continue to benchmark this measure against comparable Utilities. In this way we can demonstrate how productive we are against peer utilities.

a) Provide a copy of the latest Benchmarking study.
b) Update Hydro One's metrics in the benchmarking study for the historic years and Bridge year and forecast test years.
c) Provide the following Metrics for the Historic years Bridge year and forecast test years:
    i. OM&A per customer
    ii. OM&A per Gw transmitted

Response

a) See Exhibit I, Tab 1, Schedule 8 for key tables and relevant reports.

b) Hydro One's metric in the benchmarking study have been updated as per the table below

Description	**Historic**			**Bridge**	**Forecast**		
	2006	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**
Transmission Line Capital Spending per Asset (%)	2.33	4.30	4.10	6.40	4.80	5.16	3.08
Transmission Line O&M Expense per Asset (%)	0.82	1.07	0.93	1.17	.99	.93	.88
Transmission Substation Capital Spending per Asset (%)	4.22	5.20	5.85	7.36	7.82	9.56	7.96
Transmission Substation O&M Expense per Asset (%)	2.00	2.37	2.75	2.73	3.30	2.13	1.96

Note : The GFA value for Substations and Lines is an estimate based on the total GFA growth for 2010, 2011 and 2012.

c)

Description	**Historic**				**Bridge**	**Forecast**	
	2006	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**
OM&A per customer	94	103	93	105	110	109	113
OM&A per GW Transmitted	2.48	2.71	2.50	3.01	3.18	3.19	3.33

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

Interrogatory

Issue 3.1: Are the proposed spending levels for, Sustaining, Development and Operations OM&A in 2011 and 2012 appropriate, including consideration of factors such as system reliability and asset condition?

Reference: Exhibit C1/Tab 2/Schedule 1/Page 2 Table 1

a) Based on Table 1 provide a benchmark analysis of Hydro One's overall OM&A:
   i. OM&A per MW peak
   ii. OM&A per MWH energy transmitted
   iii. OM&A per customer
   iv. OM&A per Km of transmission line
b) Provide in table form the data used to generate the ratios.
c) Graph the ratios and discuss trends.
d) Provide a comparison to other neighboring jurisdictions including interconnected transmission.
e) If other cost comparisons are available from the IESO or NERC please provide these.

Response

a) Hydro One does not participate in any benchmarking study for OM&A. First Quartile Consulting community study has benchmarks using O&M measures. A copy of the latest benchmarking study for Capital and O&M costs per Asset are provided in Attachment 1. Hydro One is marked on each chart. There are no transmission benchmarking analysis on

   i) OM&A per MW peak
   ii) OM&A per customer

b) The data used to generate benchmark community study ratios for Transmission Line O&M Expense per MWh transmitted are as follows:-

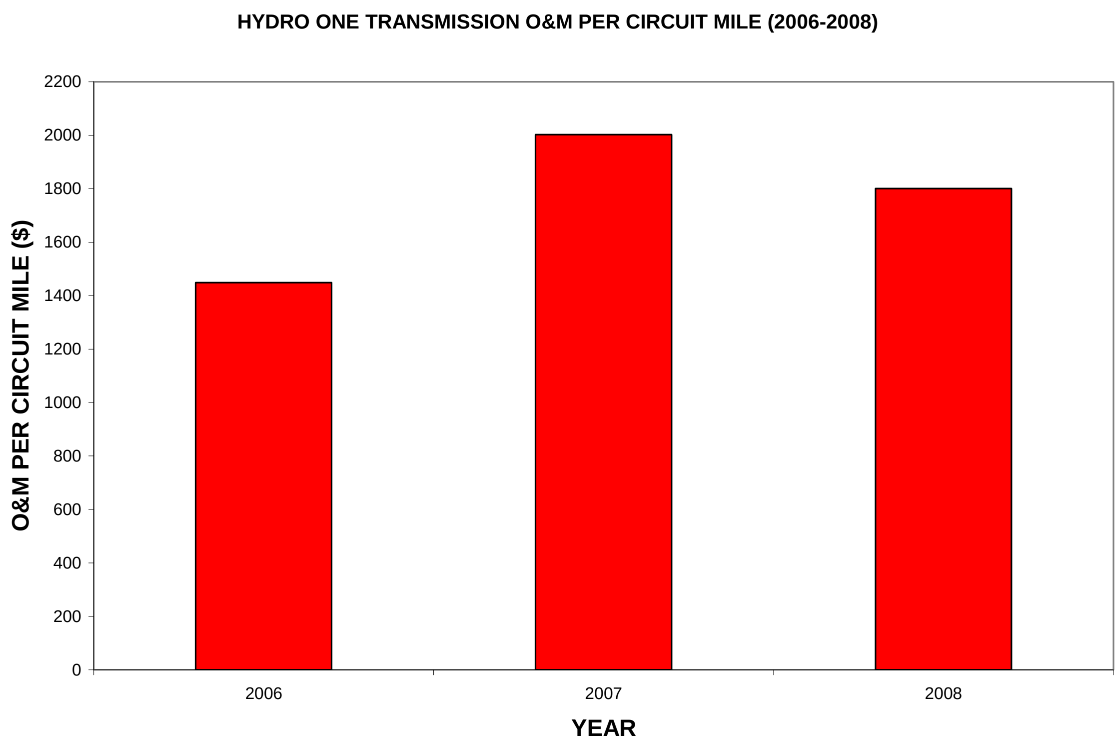
Description	2008 value
Transmission Line O&M Expense	34M ($CAN) [$31.9M ($US)]
GWh transmitted	148,700
Transmission Line O&M Expense per MWh transmitted	0.22($CAN) [$0.21($US)]

The data used to generate benchmark ratios for Transmission Line O&M Expense per circuit mile are as follows:-

Description	2008 value
Transmission Line O&M expense	34M($CAN) [31.9M($US)]
Transmission Circuit Mile	17,709 miles
Transmission Line O&M Expense per circuit mile	1920($CAN) [1801 $US)]

c) A 3 year trend with data from the benchmarking community is only available for O&M per Transmission circuit mile ratio. Hydro One's maintenance costs increased in 2007 compared to 2006 due to increased helicopter usage in the North which increased TWE Costs and downtime, higher brush densities requiring additional labour and herbicides to complete and a delayed start to the program which reduced productivity in the South.

In addition the average annual US exchange rate used in the following charts for 2006 was 1.134 and for 2007 was 1.075.

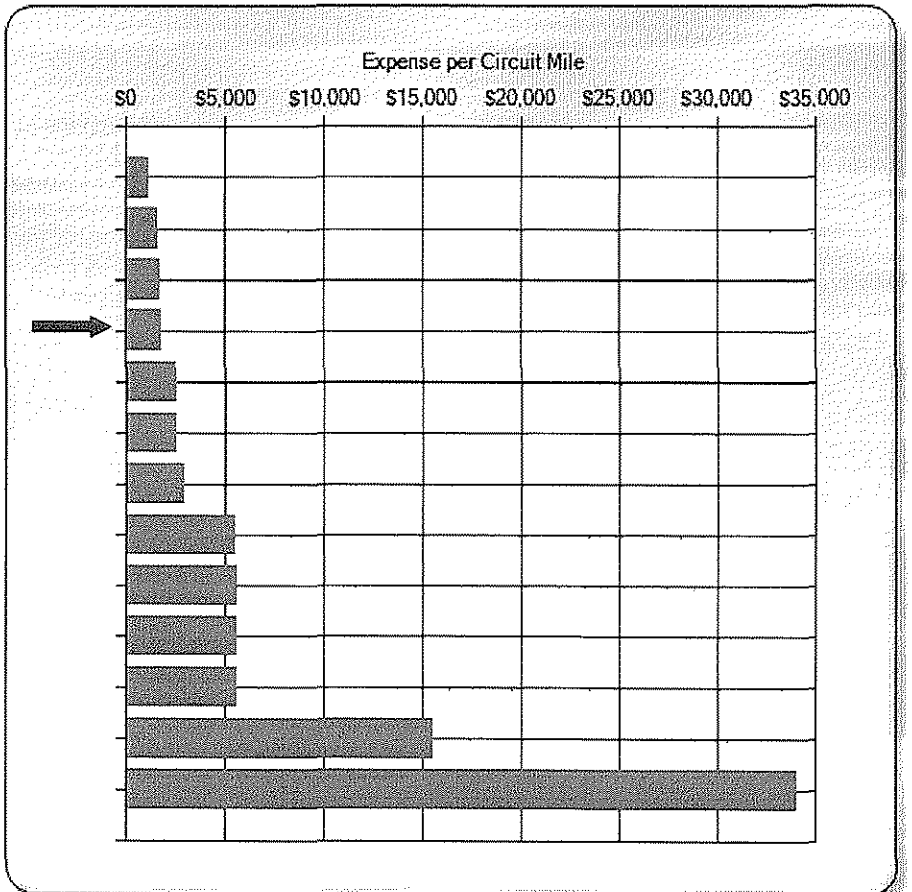


d) A comparison between Hydro One and neighboring or interconnected transmission jurisdictions is not available.

e) There are no cost comparisons available from the IESO or NERC.

Filed: August 16, 2010
EB-2010-0002
Exhibit I-4-22
Attachment 1
Page 1 of 2

TRANSMISSION LINES O&M EXPENSE PER CIRCUIT MILE [FERC] [09]



Mean Quartile

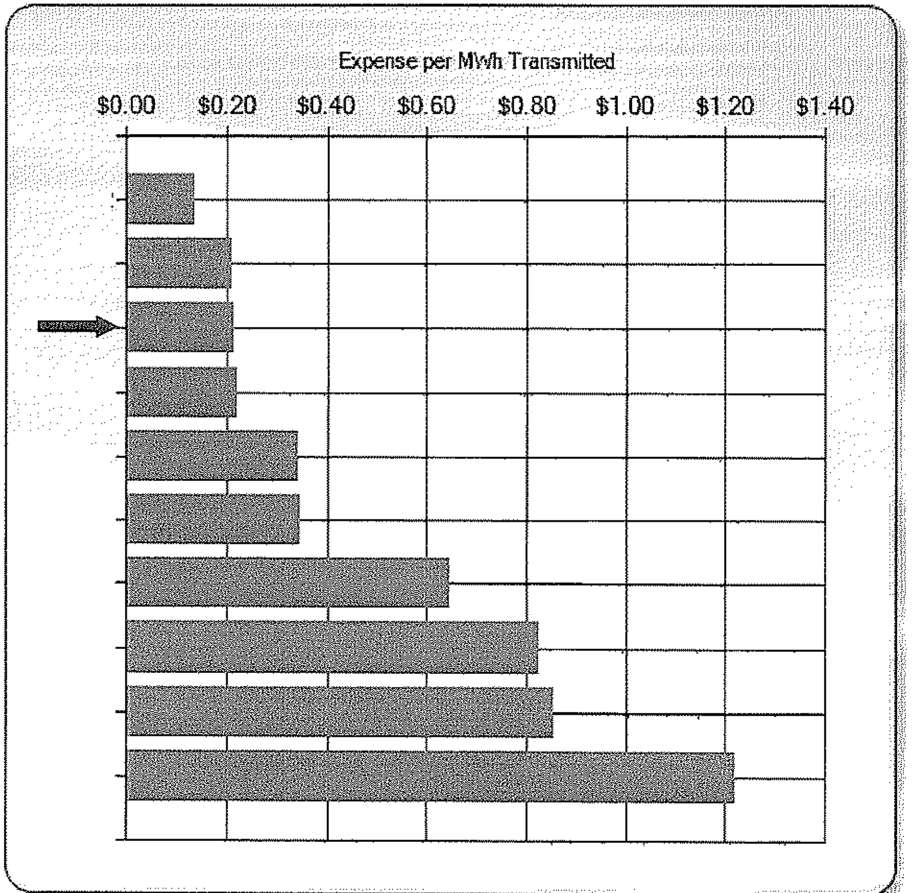
Mean	$6,645
Quartile 1	$1,801
Quartile 2:	$2,921
Quartile 3:	$5,626

Comments

Calculation used

(Trans Lines O&M FERC) / (Trans Circ Mile 09)

TRANSMISSION LINES O&M EXPENSE PER MWH TRANSMITTED [FERC]



Mean Quartile

Mean	$0.50
Quartile 1	$0.22
Quartile 2:	$0.34
Quartile 3:	$0.78

Comments

Calculation used

(Trans Lines O&M FERC) / A160.1

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #23 List 1

Interrogatory

Issue 3.1: Are the proposed spending levels for, Sustaining, Development and Operations OM&A in 2011 and 2012 appropriate, including consideration of factors such as system reliability and asset condition?

Reference: Exhibit C1/Tab 2/Schedule 1/Page 5/ Tables 2 and 3

a) Provide an updated version of Table 3 that provides 2010 Board-Approved OM&A and 2010 YTD and forecast 2010 year end OM&A.
b) In Table 3, provide a variance explanation of the increase in 2009 Shared Services & Other Costs. Relate this to the claimed cost reductions from Cornerstone.
c) Provide an updated variance explanation for any material change in forecast 2010 OM&A by category. Where relevant also relate this to cost reductions from Cornerstone.

Response

a)

Table 3
2010 Board Approved versus 2010 Projected OM&A Expenditures

OM&A ($)	2010 June YTD	2010 Board Approved	2010 Bridge[1]	Variance ($ million)
Sustaining	105.0	225.1	224.4	(0.7)
Development	6.4	13.1	19.0	5.9
Operations	28.8	58.9	62.1	3.2
Customer Care	0.4	1.5	1.1	(0.4)
Shared Services & Other Costs	35.8	55.8	58.6	2.8
Taxes other than Income Taxes	32.9	71.8	69.4	(2.4)
Total	**209.3**	**426.2**	**434.5**	**8.3**

[1] The forecast 2010 year-end OM&A is the filed Bridge year total.

b) Please note this interrogatory requests a variance explanation of the increase in 2009 Shared Services & Other Costs yet references Table 3, which cites 2010 numbers. We will interpret this as asking for the variance explanation of the increase in 2009 Shared Services & Other Cost, referencing to Table 2, citing 2009 numbers.

The approved 2009 Shared Services and Other Costs was $61.1M million; however 2009 actual spending was $70.8M, a $9.7M variance. This resulted as a consequence of increased cost of good sold[1] associated with external work of $9.3M and increased SAP sustainment costs of $7.4M.

c) The 2010 forecast amount is the as filed Bridge year amount.

[1] The increased cost of goods sold in 2009 is offset by higher miscellaneous external revenue. The net difference between these two amounts has been placed into the "External Stations Maintenance and E&CS Revenue" variance account.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #24 List 1

Interrogatory

Issue 3.1: Are the proposed spending levels for, Sustaining, Development and Operations OM&A in 2011 and 2012 appropriate, including consideration of factors such as system reliability and asset condition?

Reference Exhibit C1/Tab 2/Schedule 3/Page 3/Table 1

a) Provide a schedule that compares the Board – approved Sustaining OM&A spending for 2009 with the actual level of Sustaining OM&A for 2009 using a similar break down. Please explain major variances by line item.
b) Provide an Update of the 2010 Bridge Year Sustaining OM&A compared to the Board Approved. Please Explain YTD major variances.
c) For 2011 and 2012 please explain major drivers and why Stations require significantly increased maintenance despite the replacement/upgrade Capital program.
d) Explain in more detail than provided on page 26 the drivers for the significant increase in OM&A for Ancillary Systems.

Response

a) The Board's Decision was provided at the Sustaining OM&A level, not at the same level of detail as provided in Table 1 of Exhibit C1, Tab 2, Schedule 3. The following table summarizes 2009 actual spending against Hydro One's plan following the Decision.

Description	**2009 OEB Approved (M$)**	**2009 Actual(M$)**	**Variance (M$)**
Stations	152.6	151.6	-1.0
Lines	48.7	49.4	0.7
Engineering and Environmental Support	10.2	12.5	2.3
Total	**211.5**	**213.5**	**2.0**

- The overall 2009 Sustaining OM&A actual spending was less than 0.9 % difference than the 2009 Board approved amount.
- Stations variance is attributed to fewer planned transformer refurbishment as indicated in Exhibit I, Tab 2, Schedule 8, and slightly higher than planned costs associated with site infrastructure demand maintenance.
- Lines variance is due to demand leak detection activities associated with the H2JK underground cable, which is being replaced in the test years
- Engineering and Environmental Support variance is attributed to an increase in demand associated with engineering support and records management.

b) The Board's Decision was provided at the Sustaining OM&A level, not at the same level of detail as provided in Table 1 of Exhibit C1, Tab 2, Schedule 3. The following table summarizes 2010 projected spending against Hydro One's plan following the Decision.

Description	**2010 OEB Approved (M$)**	**2010 Forecast (M$)**	**Variance (M$)**
Stations	166.1	164.9	-1.2
Lines	48.8	48.0	-0.8
Engineering and Environmental Support	10.2	11.5	1.3
Total	**225.1**	**224.4**	**-0.7**

The overall 2010 Sustaining OM&A projection is in-line with the 2010 Board approved amount.

c) The increase in Stations OM&A from historic years is primarily driven by the following issues:
- New work to comply with Environment Canada's PCB Regulations for oil-filled station equipment
- New work to comply with NERC Cyber Security regulations and added maintenance of protection and control assets to comply with new regulations
- Increasing need for mid-life maintenance and refurbishment of transformers and circuit breakers to maintain reliability
- Upward pressures on power equipment and ancillary maintenance due to aging infrastructure

Stations OM&A planned cost for the 2011 test year is a 3.4% increase from bridge year projections and 2012 test year is a 3.2% increase from 2011.

Despite the increasing Capital investment, the demographics of the asset base result in continued upward pressure on the OM&A requirements to operate and maintain the system. As outlined in Exhibit D1, Tab 2, Schedule 1, Page 2, "the investments that Hydro One is making in the test years will not arrest these long term demographic trends", as the number of assets replaced in the test years under the Sustaining Capital investments is a relatively small number compared to the overall fleet. It should also be observed that the future OM&A costs for the assets being replaced in the test years have already been discounted when determining the test years' requirements for Stations OM&A.

d) Please refer to Exhibit I, Tab 1, Schedule 40.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #25 List 1

Interrogatory

Issues: 3.1 & 3.2; 9.1

References : i) Exhibit C1/Tab 2/Schedule 4/Page 2/Table 1;
ii) Exhibit C1/Tab 2/Schedule 4/Page 10/Table 1

a) In Table 1 (first reference) provide an overall Total for Development OM&A and a line that shows the percentage increase proposed for 2011 and 2012.

b) Extend Table 1 (second Reference) showing GEGEA Development OM&A to provide a projection for 2013 and 2014 for the 20 listed projects.

Response

a) Please see below revision of Table 1 to include Total Development OM&A and percentage increase proposed for Test Years.

Description	Historic			Bridge	Test	Test
	2007	2008	2009	2010	2011	2012
Research, Development and Demonstration	4.4	3.0	6.0	6.3	6.4	6.6
Standards Development	4.0	6.2	7.9	8.7	7.8	8.3
Smart Zone Development*				4.0	4.0	4.0
Total	**8.4**	**9.2**	**14.0**	**19.0**	**18.2**	**18.9**
Development Work for Transmission Projects – Deferral Account	0	0	1.9	8.2	35.7	46.7
Total Development OM&A (1)	**8.4**	**9.2**	**15.9**	**27.2**	**53.9**	**65.6**
Percentage Increase		**9%**	**73%**	**71%**	**98%**	**22%**

Note (1): "***Total Development OM&A***" includes "***Development OM&A***" expenditures that are included in the 2011/12 revenue requirement and also "***Development Work for Transmission Projects***" in which expenditures are accumulated in a deferral account and hence not included in the 2011/12 revenue requirement.

b) Please see the response to Board Staff Interrogatory 98.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #26 List 1

Interrogatory

Issues: 3.1 & 3.2; 9.1

Reference: Exhibit C1/Tab 4/Schedule 1/Page 15 Table 3 Fleet Management Budget

a) Confirm whether or not the figures in Table 3 include HST.
b) Indicate the amount of the increase/decrease in categories 1 and 3 that is attributable to HST.
c) For Operations and Repairs indicate how much is outsourced and the basis of the charges.
d) For the fuel cost estimate provide the basis of the 2011 and 2012 projections.

Response

a) No, the figures in Table 3 only include applicable PST charges.

b) Hydro One is in the process of establishing the methodology that will capture the revenue requirement impact driven by the harmonization of the PST and GST. Our current best estimate of the amounts that are included in 2011 and 2012 in categories 1 through 3 are $1.7 million and $1.8 million in 2011 and 2012, respectively.

c) $14.4 million of the $60.2 million in 2011 and $14.8 million of the $61.8 million in 2012 is for external repair charges.

d) The fuel cost estimate for 2011 and 2012 is based on our 2010 year-end forecast, plus 3% per year

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #27 List 1

Interrogatory

Issues: 3.1 & 3.2; 9.1

References: i) Exhibit C1/Tab 6/Schedule 1/Page 2 Table 1;
ii) Exhibit C2/Tab 4/Schedule 1/Page 1

a) Provide an explanation of the drivers for increased Asset Removal costs in 2010-2012.

Response

Asset Removal costs are increasing as a result of increasing sustaining capital replacement programs that are seeing a greater number of assets taken out of service and replaced.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #28 List 1

Interrogatory

Issues: 3.1 and 4.2

Reference: i) Exhibit A, Tab 13, Schedule 1
ii) BC Hydro's F2011 Revenue Requirement Application, page 2-10
(http://www.bcuc.com/Documents/Proceedings/2010/DOC_24719_B-1_BCHydro-F11RR-Application.pdf)

a) In its F2011 Rate Application, BC Hydro indicated that it participated in T&D Benchmarking Studies undertaken by First Quartile Consulting in 2008 and 2009. Did Hydro One Networks participate in either of these benchmarking studies? If yes, please provide copies of the relevant reports and identify Hydro One Networks' participant code.

Response

a) Yes, Hydro One participated in the 2008 and 2009 community study. See Exhibit I, Tab 1, Schedule 8 for the key tables and relevant reports.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #29 List 1

Interrogatory

Issues: 3.1 and 4.2

References: i) EB-2008-0272, Exhibit J2.7
ii) Exhibit A, Tab 12, Schedule 5, pages 4-8

a) Please provide an updated version of Exhibit J2.7 that sets out the minimum and proposed OM&A and Capital Spending for 2011 and 2012 as established by Hydro One Networks' Investment Prioritization Process.

Response

a) By definition, the Business Plan represents the minimum aggregate set of investments as determined through the investment planning process outlined in Exhibit A, Tab 12, Schedule 5.

The investment planning process requires a number of alternatives for each category of investment and the lowest expenditure level is referred to as the Minimum and upper levels are generally a level 2 or 3. In most cases, with the exception of demand work, the level of investment that mitigates risks to an acceptable degree is between the minimum and upper level. The plan in this submission has gone through the prioritization process and represents the levels of investment to manage risks at acceptable levels over the test years.

Hydro One applies the risk based prioritization process to establish a uniform view of investments, recognizing that the investments differ in many ways, e.g., protection and controls as compared to vegetation management. In order to arrive at this common understanding of risk, the process requires a number of alternatives for each investment category to derive the appropriate level of investment. The minimum in most cases is used to facilitate the process, or provide a lower bound in order to zero in on the acceptable level from a perspective of risk mitigation. In most cases the process requires the selection of an extreme lower bound that would plan for a medium likelihood of severe occurrences, such as just recently occurred at Manby TS, refer to Exhibit I, Tab 1, Schedule12. Hydro One would never plan for such events, but that could be the consequence of selecting a minimum level without a detailed understanding of the prioritization process and the possible outcome. Furthermore, if one were to reduce a number of investments to the minimum level, the likelihood of a severe event would increase.

As well, the minimum levels do not provide for long term sustainability of the assets. For example, in a number of cases reliability would drift lower and at some point in the future, investments would need to increase to renew the condition and performance of these assets.

Considering these aspects, using the minimum as a point of reference is discouraged, as it truly does not represent a plan that is in the best interest of the rate payers and the province.

HYDRO ONE NETWORKS INC.
TRANSMISSION OM&A 2011/2012 PLAN

	2011			2012		
	Filed	Minimum Level	Variance	Filed	Minimum Level	Variance
Sustaining						
Stations						
Land Assessment and Remediation	1.1	0.9	0.2	1.1	0.9	0.2
Environmental Management	14.0	10.5	3.5	15.4	11.4	4.0
Power Equipment	67.4	62.3	5.1	67.7	65.9	1.9
Protection, Control, Monitoring, Metering and Telecommunications	44.5	43.6	0.9	46.6	45.0	1.6
Ancillary Systems Maintenance	15.8	16.1	-0.3	16.6	17.7	-1.1
Infrastructure Maintenance	27.9	23.9	4.0	28.7	24.9	3.9
Total Stations	**170.7**	**157.4**	**13.3**	**176.3**	**165.8**	**10.5**
Lines						
Vegetation Management	27.5	24.8	2.7	28.3	25.4	3.0
Overhead Lines Programs	20.2	18.0	2.2	23.0	16.3	6.8
Underground Cable Program	3.8	2.7	1.1	4.0	2.8	1.2
Total Lines	**51.4**	**45.5**	**5.9**	**55.4**	**44.4**	**11.0**
Engineering and Environmental Support	**11.0**	**9.2**	**1.8**	**11.8**	**9.7**	**2.1**
Total Sustaining	**233.0**	**212.0**	**21.0**	**243.5**	**220.0**	**23.6**
Development						
Research and Development	6.4	6.3	0.1	6.6	6.5	0.1
Standards Development	7.8	3.9	3.9	8.3	4.2	4.1
IPSP Development Projects	33.7	33.7	0.0	41.6	41.6	0.1
Smart Grid	4.0	4.0	0.0	4.0	4.0	0.0
Total Development	**51.9**	**47.9**	**3.9**	**60.6**	**56.4**	**4.2**
Operations						
Operation	38.0	38.0	0.0	38.3	38.3	0.0
Operations Support	24.8	21.2	3.6	25.9	22.2	3.8
Environmental, Health & Safety	3.5	2.8	0.7	4.0	3.3	0.7
Total Operations	**66.3**	**62.1**	**4.2**	**68.2**	**63.7**	**4.5**
TOTAL Sustaining, Development & Operations	**351.2**	**322.0**	**29.1**	**372.4**	**340.0**	**32.3**
Shared Services and Other Costs						
Asset Management costs	34.6	34.6	0.0	34.9	34.9	0.0
Common Corporate Functions & Services costs	100.8	100.8	0.0	98.3	98.3	0.0
Customer care	1.1	1.1	0.0	0.6	0.6	0.0
Information Technology	58.2	52.8	5.4	58.8	54.2	4.7
Cost of Sales	14.9	14.9	0.0	8.5	8.5	0.0
Cornerstone	-12.5	-12.5	0.0	-21.4	-21.4	0.0
Other	-182.6	-182.6	0.0	-174.3	-174.3	0.0
Total Shared Services and Other Costs	**14.4**	**9.0**	**5.4**	**5.5**	**0.8**	**4.7**
Property Taxes & Rights Payments	**70.8**	**70.8**	**0.0**	**72.2**	**72.2**	**0.0**
TOTALTransmission OM&A	**436.3**	**401.8**	**34.5**	**450.0**	**413.0**	**37.0**

HYDRO ONE NETWORKS INC.
TRANSMISSION CAPITAL 2011/2012 PLAN

	2011			2012		
	Filed	Minimum Level	Variance	Filed	Minimum Level	Variance
Sustaining						
Stations						
Circuit Breakers	23.6	20.3	3.3	24.9	25.3	-0.4
Station Facility Re-investment	84.0	70.0	14.0	84.7	83.2	1.4
Power Transformers	63.5	54.8	8.7	65.7	63.2	2.4
Other Power Equipment	19.6	11.8	7.8	21.2	12.2	9.0
Protection, Control, Monitoring and Telecommunications	93.8	88.4	5.3	107.5	99.8	7.7
Ancillary Systems	18.0	13.1	4.9	18.1	13.3	4.9
Transmission Site Facilities and Infrastructure	26.5	10.6	15.9	26.4	11.3	15.1
Stations Environment	8.4	4.2	4.2	8.5	4.3	4.3
Total Stations	**337.3**	**273.1**	**64.1**	**356.9**	**312.6**	**44.4**
Lines						
Overhead Lines Refurbishment and Component Replacement	55.6	43.7	11.9	57.6	44.0	13.6
Transmission Lines Re-Investment	8.9	10.5	-1.6	7.3	0.0	7.3
Underground Lines Cable Refurbishment and Replacement	22.2	12.5	9.7	21.6	13.1	8.5
Total Lines	**86.7**	**66.6**	**20.1**	**86.5**	**57.2**	**29.3**
Total Sustaining	**424.0**	**339.8**	**84.2**	**443.4**	**369.7**	**73.7**
Development						
Inter Area Network Transfer Capability	307.9	349.8	-41.9	139.3	317.4	-178.1
Local Area Supply Adequacy	150.5	145.7	4.8	101.4	94.7	6.7
Load Customer Connection	81.8	89.9	-8.1	84.7	81.8	2.9
P&C Enablement for Generation Connections	11.4	23.5	-12.1	36.0	37.4	-1.4
TS Upgrades to Facilitate Distribution Generation	33.8	69.0	-35.2	81.4	114.0	-32.6
Performance Enhancement and Risk Mitigation	24.0	21.8	2.2	7.2	6.2	1.0
Smart Grid	7.8	1.5	6.3	6.8	1.2	5.6
Total Development	**617.2**	**701.4**	**-84.2**	**456.8**	**652.7**	**-195.9**
Operating						
Grid Operating and Control Facilities	22.6	12.9	9.7	18.5	12.3	6.2
Integrating Operating Infrastructure	21.7	24.1	-2.4	38.9	25.7	13.2
Total Operating	**44.3**	**36.9**	**7.4**	**57.4**	**38.0**	**19.4**
TOTAL Sustaining, Development & Operations	**1085.5**	**1078.2**	**7.3**	**957.6**	**1060.4**	**-102.8**
Shared Services and Other Costs						
Transport, Work & Service Equipment	21.6	20.4	1.1	17.0	15.8	1.2
Information Technology	17.2	10.3	6.9	13.3	9.0	4.4
Cornerstone	3.7	2.3	1.4	1.3	0.5	0.8
Facilities and Real Estate	23.9	22.3	1.6	19.1	5.2	13.9
Conservation and Demand Management	0.0	0.0	0.0	0.0	0.0	0.0
Total Shared Services and Other Costs	**66.4**	**55.3**	**11.1**	**50.7**	**30.5**	**20.2**
TOTAL Transmission Capital	**1151.9**	**1133.5**	**18.4**	**1008.3**	**1090.9**	**-82.6**

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #30 List 1

Interrogatory

Issue 3.2: Are the proposed spending levels for Shared Services and Other O&M in 2011 and 2012 appropriate?

Issue 3.4: 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 2011/12 appropriate?

Reference: Exhibit A/Tab 7/Schedule 3/Page 6/Table 2

a) Explain the decrease in 2010-2012 General Counsel and Secretary Service costs charged to affiliates.

b) Explain the decrease 2010-2012 in Financial Services costs charged to affiliates.

c) Confirm that due to lower recoveries, the amount of costs for the above referenced services at Hydro One Networks is increased in 2010-1012. Provide the increase in these costs.

Response

a) General Counsel and Secretary costs charged to the affiliates decreased from 2010 to 2012 as a result of the expected completion of the Records Management project.

b) Financial Services costs charged to affiliates decrease from 2010 to 2012 as a result of lower IFRS costs.

c) General Counsel and Secretary and Financial Services costs allocated to Networks do not increase from 2010 to 2012 as a result of lower recoveries.

Networks Allocation	2010	2012	Change
General Counsel and Secretary	29.1	30.6	1.5
Financial Services	22.0	20.2	(1.8)

General Counsel and Secretary costs charged to the Affiliates include the Regulatory Affairs department. From 2010 to 2012, Regulatory Affairs costs increase primarily as a result of new National Energy Board cost recovery fees charged to Hydro One Networks.

Financial Services costs decrease by $1.8M from 2010 to 2012 primarily due to lower IFRS implementation costs.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #31 List 1

Interrogatory

Issue 3.2: Are the proposed spending levels for Shared Services and Other O&M in 2011 and 2012 appropriate?
Issue 3.4: 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 2011/12 appropriate?

Reference: Exhibit A/Tab 7/Schedule 3/Page 8

a) Explain the more than 10% increase in 2011/12 charges to Hydro One Networks from Telecommunication Services from 2010.
b) Provide the multi-year costs for telecom services 2008-2012.
c) Compute the year over year % increases and the overall increase from 2008 to 2012.
d) Provide a detailed explanation of the multi year and test year cost increases with reference to cost drivers such as employees.
e) How does Hydro One Networks know that its 2011 and 2012 telecommunications services and costs are at market rates?

Response

a) The increases in Telecom Services cost in 2011 and 2012 are due to increases in labour costs as per collective agreements and increases in service capacity to continue meet HON business and power system operations demands.

b) The annual cost for Telecom Services (in $Thousands) is: 9,002 in 2008; 9,567 in 2009; 10,208 in 2010; 10,739 in 2011; and 11,297 in 2012.

c) The year over year percentage increase is 6.3% from 2008-09, 6.7% from 2009-10, 5.2% from 2010-11, and 5.2% from 2011-12. This equates to a 25.5% overall increase for the five years from 2008 to 2012.

d) The increases are primarily due to labour cost increases as per negotiated collective agreements and additional telecom/security monitoring and management services required of the service provider. The year over year cost increases are driven by an increase in the scope of data networks being managed with the following services: Alarm Based Monitoring, Coordinated Network Management, Systems Analysis Services, and Carrier/Vendor Management Services.

e) Hydro One Networks engaged the Shpigler Group, a strategy management consulting firm specializing in telecommunication and technology, in 2006 and 2008 to perform an independent service review and market benchmarking assessment for the services provided by its telecom affiliate. The report concluded the contracted costs are indicative of fair market value. The reports reaffirmed the conclusion that Hydro One obtains commercial and operations benefit through its relationship with Hydro One Telecom. These costs were deemed acceptable by the Board in the EB-2008-0272 Transmission proceedings. Considering the services in 2011 and 2012 are an extension of existing services provided by Hydro One Telecom, Hydro One Networks feels the costs are consistent with the findings of the previous reports.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #32 List 1

Interrogatory

Issue 3.2: **Are the proposed spending levels for Shared Services and Other O&M in 2011 and 2012 appropriate?**
Issue 3.4: **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 2011/12 appropriate?**

Reference: Exhibit A/Tab 7/Schedule 3/Page 6/Table 2

a) Describe the basis on which the charges for the services provided by Hydro One Networks were established.

Response

As described at page 5 of Exhibit A, Tab 7, Schedule 3 the charges for services provided by Hydro One Networks are no less than the greater of (i) the market price of that service, product, resource or use of asset and (ii) the utility's fully-allocated cost to provide that service, product, resource or use of asset.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #33 List 1

Interrogatory

Issue 3.2: Are the proposed spending levels for Shared Services and Other O&M in 2011 and 2012 appropriate?
Issue 3.4: 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 2011/12 appropriate?

Reference: Exhibit A/Tab7/Schedule3/Appendix A

a) Provide a copy of the 2011 and 2012 Affiliate Services Agreements and/or Schedules A and B (pricing) of 2011/2012 services and costs corresponding to Exhibit A/Tab 7/Schedule 3/Page 6/Tables 2 and 3

Response

Affiliate Service Agreements for Shared Services are only signed for a one year term (current year). Agreements for 2011 and 2012 have not been signed.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #34 List 1

Interrogatory

Issue 3.2: Are the proposed spending levels for Shared Services and Other O&M in 2011 and 2012 appropriate?

Issue 3.4: 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 2011/12 appropriate?

References: i) Exhibit C1/Tab 2/Schedule 7/Page 2 Table 1;
ii) Exhibit C1/Tab 5/Schedule 1/Page 3 Table 1 and Table 2;
iii) Exhibit C1-5-1Attachment 1

a) The first reference shows total CCFS costs of $155 million in 2011 and 162.1 million in 2012. The second reference shows Total CCFS costs of $101 million in 2011 and 107.2 million in 2012. The difference appears to be Real Estate Costs -please confirm this is the only difference.
b) Provide a version of Exhibit C1/Tab 2/Schedule 7/Page 2 Table 1 that shows the total year over year % increase and the % increase in allocation to Tx.
c) C1-5-1, Attachment 1 page 2 indicates "The Updated BP 2010-2014 includes 2011 costs aggregating approximately C$303.3 million and 2012 costs aggregating approximately C$324.9 million, incurred to provide the corporate functions and services" and "Approximately 43% of the CF&S costs are incurred under an outsourcing arrangement with Inergi LP ("Inergi"). In this Report, CF&S includes the portions of Inergi services identified in Updated BP 2010-2014 as sustainment". Reconcile this statement with costs shown at C1/Tab 5/Schedule 1/Page 3 Table 1 and Table 2.
d) Provide a version of C1/Tab 2/Schedule 7/Page 2 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.
e) Reconcile the CCFS costs for 2011 and 2012 with the Schedules in the Service Level Agreements for the two years.

Response

a) Confirmed.

b) Provided below is the requested table that shows the total year over year % increase and the % increase in allocation to Transmission.

Description	Historic		Bridge	Test		Transmission Allocation Test
	2008 over 2007	2009 over 2008	2010 over 2009	2011 over 2010	2012 over 2011	2012 over 2011
Corporate Management	7%	0%	-12%	-2%	0%	4%
Finance	24%	11%	-2%	-3%	-1%	-1%
Human Resources	11%	15%	13%	6%	4%	4%
Corporate Communications	19%	22%	16%	6%	34%	72%
General Counsel and Secretariat	-19%	3%	23%	14%	-7%	-6%
Regulatory Affairs	-9%	1%	4%	2%	9%	17%
Corporate Security	24%	0%	29%	4%	4%	0%
Internal Audit	-4%	8%	7%	3%	3%	0%
Real Estate & Facilities	12%	21%	16%	-8%	2%	3%
Total CCF&S Costs	**8%**	**13%**	**9%**	**-1%**	**5%**	**9%**

c) Inergi costs represent 42% & 41% of the total CCF&S costs, as displayed in Table 1 below. The amounts shown as Inergi-CCFS costs are included in the Finance and Human Resources figures provided in Exhibit C1, Tab 5, Schedule 1, Tables 1 and 2.

Table 1	**2011 $**	**2011%**	**2012**	**2012%**
Inergi-CCFS	14.9	5%	15.3	5%
Inergi-Other	110.1	37%	111.9	36%
Total Inergi	125.0	42%	127.2	41%
Total CCFS	297.2	100%	309.8	100%

The B&V *Review of Shared Services Cost Methodology* report (Exhibit C1, Tab 5, Schedule 1, Attachment 1) indicates 43% of CF&S costs are related to the Inergi LP outsourcing agreement vs. 42% & 41% in table 1 above. The figures in the B&V report were based on the financial information prepared for the February 2010 version of the 2010 Budget and 2011/12 Outlook. Although the 2010 Budget and 2011/12 Outlook was subsequently updated for the 2011-12 Transmission Rate application, Hydro One did not ask B&V to update their report. The methodology Hydro One used to update the 2010 Budget and 2011/12 Outlook figures for the Transmission filing was the same methodology reviewed by B&V in their February 2010 report. The only difference between the figures used in this application vs. the B&V report is the actual plan dollars used.

d) The table below shows how Exhibit C1, Tab 2, Schedule 7, table 1 reconciles with the updated total CCFS costs used in the Shared Services Cost Allocation model.

	Test		Transmission Allocation	
Description	2011	2012	2011	2012
Corporate Management	5.2	5.2	2.6	2.7
Finance	29.1	28.8	14.5	14.4
Human Resources	18.6	19.3	9.6	10.0
Corporate Communications	12.4	16.6	6.0	10.3
General Counsel and Secretariat	9.2	8.6	4.8	4.5
Regulatory Affairs	20.7	22.6	11.3	13.2
Corporate Security	2.8	2.9	1.3	1.3
Internal Audit	3.0	3.1	1.9	1.9
Real Estate & Facilities	54.0	55.0	27.6	28.3
CF&S$_1$	**155.0**	**162.1**	**79.7**	**86.6**
Customer Care Services	**40.7**	**43.9**	**0.5**	**0.7**
Facilities$_2$	**(45.2)**	**(45.6)**	**(20.4)**	**(20.6)**
Information Technology Systems	**110.3**	**112.7**	**50.4**	**51.8**
Supply Chain Services	**35.2**	**35.3**	**0.0**	**0.0**
Other	**1.3**	**1.3**	**0.0**	**0.0**
Total CCFS	**297.2**	**309.8**	**110.2**	**118.5**

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.

Provided below is an updated Table 3 of the B&V report in Exhibit C1, Tab 5, Schedule 1, Attachment 1. This table has been updated to reflect the CCFS costs used in this Transmission application.

Table 3. 2011 AND 2012 CF&S COSTS, UPDATED BUSINESS PLAN 2010-14

	2011 Budget		2011 Budget	
Business Unit	**$ Millions**	**% of Total**	**$ Millions**	**% of Total**
Transmission	**110.2**	**37.1%**	**118.5**	**38.3%**
Distribution	**145.2**	**48.9%**	**149.4**	**48.2%**
Others	**41.8**	**14.0%**	**41.8**	**13.5%**
Total CCFS	**297.2**	**100.0%**	**309.8**	**100.0%**

e) Tables below reconcile the updated total CCFS costs for 2011 and 2012 respectively with the Schedules in the Service Level Agreements as outlined in Exhibit A, Tab 7, Schedule3, Table 2 and Table 3.

Description	**2011**						
	Total	**Networks**	**Telecom**	**Brampton**	**Remotes**	**Hydro One Inc.**	**Materials Surcharge**
Fees Payable by Affiliates to Networks							
General Counsel and Secretary Services	29,870	29,184	92	184	318	92	0
Financial Services	21,700	20,659	311	407	305	18	0
Corporate Services	69,970	48,745	419	33	264	0	20,509
Telecommunication Services	20,820	20,406	280	0	134	0	0
Other Services	139,597	122,679	2,033	0	620	0	14,266
Total	**281,957**	**241,672**	**3,135**	**624**	**1,642**	**110**	**34,775**
Fees Payable by Networks							
General Counsel and Secretary Services	990	926	10	20	25	10	0
President / CEO / Chairman Services	3,261	3,144	26	34	18	39	0
Chief Financial Office Services	936	832	29	39	7	28	0
Total	**5,187**	**4,903**	**65**	**93**	**50**	**77**	**0**
Real Estate	**8,837**	**8,837**					
Donations	**1,250**					**1,250**	
Total CCFS[1]	**297,231**	**255,412**	**3,200**	**716**	**1,691**	**1,436**	**34,775**

Note 1: Total CCFS costs do not include CEO/President for Remotes Services, Utility Operation Services, Joint Use Services provided by Networks and Telecommunication Services provided by Telecom, as those services are not classified as Corporate Common Services.

Description	2012						
	Total	**Networks**	**Telecom**	**Brampton**	**Remotes**	**Hydro One Inc.**	**Materials Surcharge**
Fees Payable by Affiliates to Networks							
General Counsel and Secretary Services	31,277	30,623	86	173	308	86	0
Financial Services	21,201	20,190	305	380	307	18	0
Corporate Services	75,961	54,113	436	34	274	0	21,105
Telecommunication Services	24,087	23,607	325	0	155	0	0
Other Services	141,277	124,774	2,109	0	645	0	13,749
Total	**293,803**	**253,307**	**3,261**	**587**	**1,690**	**105**	**34,853**
Fees Payable by Networks							
General Counsel and Secretary Services	1,009	944	10	20	25	10	0
President / CEO / Chairman Services	3,278	3,160	26	34	18	39	0
Chief Financial Office Services	951	846	30	39	7	29	0
Total	**5,238**	**4,950**	**66**	**94**	**50**	**78**	**0**
Real Estate	**9,464**	**9,464**					
Donations	**1,250**					**1,250**	
Total CCFS$_1$	**309,755**	**267,721**	**3,327**	**681**	**1,740**	**1,432**	**34,853**

Note 1: Total CCFS costs do not include CEO/President for Remotes Services, Utility Operation Services, Joint Use Services provided by Networks and Telecommunication Services provided by Telecom, as those services are not classified as Corporate Common Services.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #35 List 1

Interrogatory

Issue 3.3: Are the 2011/12 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?

References : i) Exhibit C1/Tab 3/Schedule 2/Page 9/Table 3 ;
ii) EB-2008-0272 Exhibit I-6-37 Attachment 1;
iii) Exhibit C2/Tab 3/Schedule 1 Tables 1,2,3

a) Provide a version of Table 3 that shows the Total Compensation for Hydro One Networks broken down between Distribution and Transmission.
b) Provide an updated copy of the IR response in the second reference.
   i. Update the 2009 data to show an actual comparison and
   ii. 2010 data to show the latest projection in comparison
c) Provide the projections for the test years 2011 and 2012.
d) Provide a comparison table that shows the increases in each category from the 2009 Board- approved data.
e) Reconcile the answers to parts b-d with disaggregated compensation for Hydro One Transmission in the requested version of Table 3 in part a).
f) Confirm that the 2005 data noted in the footnote to reference iii) Table 2 have not been filed in this case, but are the same as EB-2008-0272 Exhibit I-6-37 Attachment 1.

Response

a) The payroll costs and employee numbers cannot be separated between Transmission and Distribution. Hydro One Networks has an integrated workforce for its Transmission and Distribution businesses. This allows Hydro One to take advantage of economies of scale and efficiencies that would not be available through separate transmission and distribution operations.

b) c) Refer to Attachment 1 which is an updated version of the EB-2008-0272 Exhibit I, Tab 6, Schedule 37, Attachment 1. Please note: The Total Wages for 2010 found at Exhibit C1 Tab 3 Schedule 2 page 9 Table 3 should read $745.1 M and it has been updated in this Attachment.

d) Refer to Attachment 2 for the comparison of EB-2008-0272 2009/2010 data versus current application.

e) Refer to a) above – compensation cannot be separated between Transmission and Distribution.

f) The 2005 data noted in the footnote is the same as EB-2008-0272 Exhibit 1, Tab 6, Schedule 37, 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**

2009	# Employees			Total Wages			Base Pay			Average Base Pay		
REP	Forecasted	Actual	Diff.	Forecasted	Actual	Diff.	Forecasted	Actual	Diff.	Forecasted	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	EB-2008-0272 Forecast	Current Application Forecast	Diff.	EB-2008-0272 Forecast	Current Application Forecast	Diff.	EB-2008-0272 Forecast	Current Application Forecast	Diff.	EB-2008-0272 Forecast	Current Application Forecast	Diff.
PWU Reg	3,424	3,667	243	$313,038,398	$356,105,003	$43,066,605	$256,721,906	$276,118,903	$19,396,998	$74,977	$75,298	$321
SOCIETY Reg	1,147	1,479	332	$111,006,705	$139,154,777	$28,148,072	$108,911,113	$126,916,047	$18,004,934	$94,953	$85,812	($9,141)
MCP Reg	628	710	82	$90,329,523	$98,161,467	$7,831,943	$72,815,291	$81,986,159	$9,170,868	$115,948	$115,473	($474)
Total Reg	**5,199**	**5,856**	**657**	**$514,374,626**	**$593,421,246**	**$79,046,620**	**$438,448,309**	**$485,021,109**	**$46,572,800**	**$84,333**	**$82,825**	**($1,509)**
PWU Temp	70	234	164	$665,436	$7,051,909	$6,386,473	$1,302,103	$6,577,102	$5,274,999	$18,601	$28,107	$9,506
Society Temp	25	85	60	$174,459	$4,458,292	$4,283,833	$864,530	$4,252,267	$3,387,737	$34,581	$50,027	$15,445
MCP Temp	2	14	12	$82,281	$1,008,863	$926,582	$68,944	$997,022	$928,078	$34,472	$71,216	$36,744
Total Temp	**97**	**333**	**236**	**$922,176**	**$12,519,064**	**$11,596,888**	**$2,235,576**	**$11,826,390**	**$9,590,814**	**$23,047**	**$35,515**	**$12,468**
CASUAL	**1,776**	**2,221**	**445**	**$103,456,175**	**$139,178,355**	**$35,722,180**	**$77,316,115**	**$113,346,100**	**$36,029,985**	**$43,534**	**$51,034**	**$7,500**
Total	**7,072**	**8,410**	**1338**	**$619,900,000**	**$745,118,666**	**$125,218,666**	**$518,000,000**	**$610,193,600**	**$92,193,600**	**$73,247**	**$72,556**	**($691)**

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #36 List 1

Interrogatory

Issue 3.6: Is Hydro One Networks' proposed depreciation expense for 2011 and 2012 appropriate?

Reference: i) Exhibit A/Tab 11/Schedule 3/Page 6

Preamble: IFRS requires the use of depreciation service lives that are more reflective of the asset's actual accounting life than those used currently. This change will generally lengthen asset service lives from the lives previously mandated by the Board and will provide a depreciation expense reduction that could have the effect of offsetting the increase on revenue requirement from adopting IAS 16-compliant overhead accounting. Hydro One Transmission will not experience this offsetting impact as its depreciation service lives, as assessed by its independent depreciation consultant, will not change significantly in moving from CGAAP to MIFRS. This is because Hydro One Transmission was not subject to the Board's mandated service lives. Instead, service lives and asset componentization definitions that meet IFRS requirements were inherited from Ontario Hydro.

a) Provide a schedule that shows for major asset classes the difference between GAAP and IFRS, including Accumulated depreciation, NBV and 2011 and 2012 depreciation expense.

Response

a) Hydro One assumed that for 2012, the "CGAAP revenue requirement is generally equivalent to that calculated under IFRS." As Hydro One did not have planned depreciation expense available on an IFRS basis at the time of its submission, there was no difference in the method used to calculate CGAAP depreciation expense in the 2011 submission and IFRS depreciation expense in the 2012 submission.

However, at the time of filing, Hydro One was able to confidently estimate that IFRS depreciation expense will not be less than that determined under CGAAP. While the method of calculating depreciation will change from a group method under CGAAP to an item method under IFRS, continued use of the same underlying service life parameters and consistent asset componentization minimize the impact.

The estimated impact of depreciation expense on the CGAAP versus IFRS basis for 2010 is provided in Exhibit I, Tab 7, Schedule 6, part d).

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #37 List 1

Interrogatory

Issue 3.6: Is Hydro One Networks' proposed depreciation expense for 2011 and 2012 appropriate?

Reference: Exhibit A/Tab 11/Schedule 3/Page 8

Preamble: Finally, Hydro One Transmission is requesting that the Board approve a new Impact for Changes in IFRS Variance Account with exactly the same parameters as it recently approved for Hydro One Distribution (EB-2009-0069). This is a contingency account to guard against future changes to MIFRS that cannot be reasonably predicted at the time of filing. Such changes could possibly disadvantage either customers or the shareholder and it would be applied symmetrically.

a) Provide details of the costs that would be tracked/recorded in the proposed account and explain why these costs cannot be:
   - predicted and
   - recorded in the existing IFRS Deferral/Variance account.

Response

a) For more information on the nature of the amounts that could be recorded in the proposed account and why their nature and amount cannot reasonably be predicted now, please see Exhibit I, Tab 1, Schedule 92 parts a to d).

   Future amounts that could be recorded in this account would not qualify for inclusion in the existing IFRS deferral/variance account because this latter account only records variances between the Company's actual IFRS conversion costs and such costs included in the approved revenue requirement.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #38 List 1

Interrogatory

Issue 3.6: Is Hydro One Networks' proposed depreciation expense for 2011 and 2012 appropriate?

References: i) Exhibit C1/Tab 6/Schedule 1/Page 2 Table 1;
ii) Exhibit C2/Tab 4/Schedule 1/Page 1

a) Provide an explanation of the drivers for increased Asset Removal costs in 2010-2012

Response

Refer to Exhibit I, Tab 4, Schedule 27.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #39 List 1

Interrogatory

Issue 4.1: Are amounts proposed in rate base in 2011 and 2012 appropriate?
Issue 4.2 Are the proposed 2011 and 2012 Sustaining and Development and Operations capital expenditures appropriate, including consideration of factors such as system reliability and asset condition?

Reference: i) Exhibit D1/Tab 3/Schedule 2 ii) Exhibit A/Tab 14/Schedule 4, page 3

a) Based on Hydro One Networks' investment prioritization process please respond to the following:
   - What areas of Sustainment CAPEX would be reduced if Hydro One Networks' Sustainment funding was reduced by 10% - 20%. Please explain, with reference to risks and impacts, why these areas were selected.
   - What areas of Sustainment CAPEX would be increased if Hydro One Networks' Sustainment funding was increased by 10%-20%. Please explain, with reference to risks and impacts, why these areas were selected.

Response

SUSTAINING CAPITAL REDUCTIONS

The deferals identified below are based on a review of the risks to Hydro One's business values, (i.e., safety & environment, financial, reputation, regulatory relationship, customer/reliability, business efficiency) that were identified as part of the prioritization process for the 2011 and 2012 plan, as opposed to working through the full prioritization process. Time constrains prevented a full review of the plan as would occur through the prioritization process. Full prioritization would include the 5 year plan with required input from the field business units, various levels of management and senior management review, which was not possible. As well, consideration was given to current risks that have changed significantly since the 2011 and 2012 plan was approved. The one area where risks have increased is in the area of underground cable replacements identified in Exhibit D2, Tab 2, Schedule 3, S39, as such, these projects would not be considered for deferral.

Sustaining Capital deferrals in the order of 10% over the test years are outlined below, along with the impacts to risk and key business values. Because of the asset demographics presented in Exhibit C1, Tab2, Schedule 2, Appendix A, deferral of the Capital requirements will put compounding pressures on future spending requirements in both Capital and OM&A. Please refer to Exhibit C1, Tab 2, Schedule 2, Table 4A and

4B for additional detail between reductions in Sustaining Capital and the impact on other Capital and OM&A investment areas.

<u>Station Re-investment ($20.0 million 2011 and 2012 combined)</u>

The reduction would include deferring the Merivale TS GIS bus replacement outside of the test years, and delaying the Richview TS air-blast circuit breakers (ABCBs) replacements by approximately 18 months. Risks are as follows:

- Deferring the Merivale GIS bus replacement would continue to expose parts of the Ottawa area to single supply conditions when this poor performing equipment is out service. As well, the delay will fail to address environmental concerns with significant irreparable SF6 leaks on this end-of-life (EOL) equipment

- Deferring the Richview ABCB replacement would result in an increased risk to reliability as a result of reduced system redundancy during a forced outage of this unreliable equipment, and added failures would result in customer interruptions.

<u>Power Transformers ($12.0 million 2011 and 2012 combined)</u>

This reduction would include deferring the replacement of two EOL transformers outside the test years. This is expected to result in at least one additional transformer failure over a five year period if future replacements do not address the backlog. Potential risks include impact to system reliability following the transformer failure, as well as LDC customer concerns until the transformer can be replaced under demand conditions.

<u>Other power Equipment ($10.0 million 2011 and 2012 combined)</u>

This reduction would include deferring the replacement of approximately half of the EOL assets planned in the test years, including insulators, capacitor banks and disconnect switches. Risks are as follows:

- Deferring insulator and switch replacements would increase reliability risks with the higher likelihood of forced outages of long duration due to EOL equipment. Consequences to system reliability, possible collateral equipment damage upon failure, and placing additional risk on Hydro One staff in the vicinity at time of failure.

- Deferring capacitor bank replacements would reduce system reliability by not replacing EOL assets required for efficient operation of the power system through power factor correction and voltage support. This would result in additional operator control action which can involve taking equipment out of service increasing system vulnerabilities and a decrease in efficiency of the transmission system.

<u>Ancillary Systems ($6.0 million 2011 and 2012 combined)</u>

This reduction would include doing approximately 25% fewer EOL AC station service replacements than required in the test years. This would increase the likelihood of a transfer scheme not operating when called upon, and is estimated to result in a system impactive event at either a BES or DESN station within the next five years if the backlog is not addressed. There would also be continued risk of arc-flash exposure for Hydro One staff depending on the reliable operation of this equipment.

Stations Environment ($6.0 million 2011 and 2012 combined)

This reduction would include deferring approximately one third of the capital work required on spill containment systems. Risks associated with this include increased likelihood of releasing transformer oil into the environment, with unacceptable environmental and reputational consequences. Increased possibility for punitive fines by the Ministry of the Environment under the Environmental Protection Act.

Protection, Control, Monitoring and Telecom ($6.0 million 2011 and 2012 combined)

The reductions would include the deferral of portions of the PLC Replacements (S30), Benchboard Replacements and Programmable Synchrocheck Relays.
Risks are as follows:

- Should the PLC fail, transmission lines may be required to be removed from service and possibly curtail generation and reduce supply reliability to load stations

- Benchboards are used to locally operate a station. They would be called into service should the OGCC lose control of a station as a result of a telecom or RTU failure. Should this occur and the Benchboard is not fully functional additional staff would be required to monitor and operate the station, some planned outages would be recalled or cancelled and there is increased likelihood of operational error causing additional outages or equipment damage.

- Deferral of the Synchrocheck Relays would result in extended outages to portions of the system following a fault. This would result in longer outage duration, greater number of customers impacted and increase in switching cost.

Transmission Site Facilities and Infrastructure ($8.0 million 2011 and 2012 combined)

This reduction would result in deferring approximately half of the security upgrade investments planned in the test years. These investments are made to protect Hydro One Transmission's assets as well as enhance reliability and the safety of the public and Hydro One employees.

Failing to make required investments in this area would not only impact reliability and safety, but also increases corrective maintenance costs to repair stolen copper, and lost productivity due to the opportunity cost of repairs. There is also the risk of damage to major equipment such as transformers and breakers as a result of copper theft: protections may not operate correctly and grounding systems engineered to safely dissipate fault current may not perform as intended.

Overhead Transmission Lines ($11 million 2011 and 2012 combined)

This reduction would include the deferral of portions of steel tower coating (S35) and shieldwire replacement (S36). Risks are as follows:

- Deferring tower coating results in higher coating costs in the future due to deterioration that takes place during the deferral period. If the backlog is allowed to increase, there is the likelihood that member replacement will be required due to loss of metal. Many of Hydro One's towers are showing a significant degree of corrosion and deferral of this type of work can only be made so long until massive programs are required to deal with wide spread deterioration of tower assets.

- Deferral of shieldwire replacements increases the likelihood that a failure will occur under severe weather conditions, e.g., icing of the wire or strong winds. A break would result in a power disruption with safety risks.

<u>Transmission Line Re-Investment ($7.0 million in 2011)</u>
The reduction would defer the start of the replacement of circuit A6P (S38) by about one year. This would result in a continuation of poor reliability affecting local customers and exposure to safety risks.

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 P&C staff and the longer term benefits.

Sustaining Capital increases in the order of 10% over the test years are summarized below, along with the impacts to risk and key business values. The linkages between increases in Capital investment in various areas an be generally assessed by considering the inverse to the effects of reductions outlined in Exhibit C1, Tab 2, Schedule 2, Table 4A and 4B.

In general, additional capital spending would help maintain historical system reliability with local enhancement in reliability in specific areas, manage technical obsolescence, and manage the compounding demographic pressures of the aging asset base. If applicable, additional impacts to key business values are mentioned below. With additional Sustaining Capital, Hydro One would make additional investment in these areas:

<u>Stations ($34.0 million per year)</u>
- Circuit Breakers ($3.0 million per year)
  - Increase the number of oil circuit breakers at 230kV and 115kV terminal stations, as well as capacitor and reactor switching positions to reduce repair times thereby securing customer supply and system reliability.
  - Increase the number of SF6 breaker replacements thereby reducing environmental impact of breaker models with known SF6 leaks, as well as improve system reliability.

- Power Transformers ($7.0 to 15.0 million per year)
  - Increase the number of replacements by approximately 2-3 per year thereby ensuring that redundancy of supply is maintained with reduced risk of customer impactive outages. This is not expected to reduce failures as the system is aging quicker than replacements.

- Station Ancillary Equipment ($8.0 million per year)
  - Increase number of AC station service replacements by approximately two BES stations and three DESN stations per year
    - More quickly reduce safety risks associated with operating equipment entering EOL region
    - Ensure uninterrupted power supply to primary system elements, e.g., transformers, breakers, thereby securing the operation of station equipment. This is especially critical during fault conditions.

- Protection & Control ($6.0 million per year)

  Additional funds would be used to accelerate the replacement of end of life Protection and Telecommunication systems while recognizing resource capability limitations in the test year period. There are multiple demands on the available protection experts and this would constrain protection replacements during the test years. With these considerations, the following programs would be accelerated:
  - Station P&C Replacement (S24) (increase by $4.0 million) – This program addresses end of life protections at load supply stations in order to secure reliability of protections and system operations under fault conditions. Protections are a known long term problem and need to be addressed to restore system security.
  - DC Remote Trip Replacements (S27) ($2 million) – The rate of increase in failures of these telecom circuits and lengthening restoration times will need to addressed to restore reliability.

- Infrastructure ($8.0 million per year)
  - Increase funding to replace deluge and fire protection systems at indoor stations at or approaching their EOL region. Unreliable operation of these systems pose serious reliability and safety risks.
  - Increase building repair and roof replacement to prevent damage to electrical equipment as a result of leaking roofs. Water damage to protections and controls can seriously jeopardize the security of the transmission system.
  - Improve station drainage at a number of stations to reduce safety risk, improve working conditions and access to equipment.

<u>Lines – ($9.0 million per year)</u>

- Overhead Lines
  - Increase insulator replacements by 25%. There are signs that the integrity of insulators is deteriorating and to reduce safety risks additional replacements would be planned.
  - Increase steel tower coating and refurbishment work by 50%. This is needed work and would reduce long term sustaining challenges.
  - Increase wood structure replacements by 10%, predominately on single supply lines to improve customer reliability.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #40 List 1

Interrogatory

(Issues 4.2 and 9.1)

Reference: Exhibit D1/Tab 1/Schedule 2/Table 1

a) Provide a version of Table 1 that shows the historic year and breaks out the Capital additions in each group that are considered GEGEA/Minister's Instruction.
b) Provide a percentage increase for each capital group with and without GEGEA/Minister's Instruction Additions.
c) Provide an estimate of the revenue requirement impact for each year with and without GEGEA/Minister's Instruction Additions.

Response

a) The GEGEA/Minister's Instruction (Government Instruction) projects are only included in the Development category of Table 1. Provided below is a different version of Table 1 that includes the historic year and shows the In-Service Capital additions that are considered Government Instruction.

GEGEA: In-Service Capital Additions 2009 – 2012 ($ M)

	2009 – Historic Year	**2010 – Bridge Projected**	**Test Years**	
			2011	**2012**
Government Instruction Projects	3.3	0.6	11.4	198.9

b) Provided below is the percentage increase for the Development Capital In-Service Additions with and without Government Instruction Additions.

Total Development Capital	**Test Years**	
	2011	**2012**
With Government Instruction Projects	106%	272%
Without Government Instruction Projects	103%	229%

c) The revenue requirement impact in each of the test years that results from Government Instruction Additions is $0.9M in 2011 and $10.3M in 2012.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #41 List 1

Interrogatory

Issue 4.1: **Are amounts proposed in rate base in 2011 and 2012 appropriate?**
Issue 4.2 **Are the proposed 2011 and 2012 Sustaining and Development and Operations capital expenditures appropriate, including consideration of factors such as system reliability and asset condition?**

References: Exhibit D1/Tab 1/Schedule 3/Tables 1 and 2

a) Provide a version of Table 1 that shows the effect of the introduction of HST on July 1, 2010.
b) Provide a version of Table 2 that shows the effect of introduction of HST on July 1, 2010.

Response

Table 1
Transmission Net Cash Working Capital Requirement ($M Except Lead-Lag Days)

	Revenue Lag (Days)	**Expense Lag (Days)**	**Net Lag (Lead) (Days)**	**2011 Test Year Amount**	**2012 Test Year Amount**
	(A)	(B)	(C)	(D)	(E)
Expenses					
OM&A Expenses	36.4	21.73	14.67	431.1	444.7
Removal costs	36.4	30.02	6.38	18.2	17.9
Environmental Remediation	36.4	34.84	1.56	7.2	7.7
Interest on Long term debt	36.4	52.87	-16.47	258.7	281.2
Income tax	36.4	16.51	19.89	80.9	69.8
Total				**796.1**	**821.3**
HST (see Table 2)				308.9	310.3
TOTAL AMOUNTS PAID/ACCRUED				**1105.0**	**1131.6**
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				17.3	17.8
Removal costs				0.3	0.3
Environmental Remediation				0	0.0
Interest on Long term debt				(11.7)	(12.7)
Income tax				4.4	3.8
Total				**10.4**	**9.3**
HST (see Table 2)				(9.6)	(12.7)
NET WORKING CASH REQUIRED				**0.8**	**(3.4)**

Table 2
Transmission Summary of HST Cash Working Capital Requirement
(All Data in $M Except Lead-Lag Days)

HST Category	**2011 Test Year**		**2012 Test Year**	
		13% HST Projection		**13% HST Projection**
	(A)	(B)	(A)	(B)
Revenue	1,439.3	187.1	1540.2	200.2
OM&A Expenses	143.6	18.7	148.1	19.3
Removal costs	18.2	2.4	17.9	2.3
Environmental Remediation	7.2	0.9	7.7	1.0
Capital	767.6	99.8	673.0	87.5
TOTAL		**308.9**		**310.3**
HST (Benefit) Cost	**2011 Test Year**		**2012 Test Year**	
	Expense Leads (Days)	**HST Amounts**	**Expense Leads (Days)**	**HST Amounts**
	(C)	(D)	(C)	(D)
The values shown in the Col (D) labeled “HST Amounts” are calculated using the expense leads shown in Col (C) divided by 365 for 2011 and 366 for 2012 and multiplied by the 13% HST projected amount in Col (B)				
Revenue	(46.58)	(23.9)	(46.58)	(25.5)
OM&A Expenses	36.59	1.9	36.59	1.9
Removal costs	43.95	0.3	43.95	0.3
Environmental Remediation	43.95	0.1	43.95	0.1
Capital	43.95	12.0	43.95	10.5
TOTAL		**(9.6)**		**(12.7)**

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #42 List 1

Interrogatory

Issue 4.1: Are amounts proposed in rate base in 2011 and 2012 appropriate?
Issue 4.2 Are the proposed 2011 and 2012 Sustaining and Development and Operations capital expenditures appropriate, including consideration of factors such as system reliability and asset condition?

References: i) Exhibit D1/Tab 3/Schedule 1/Page 2/Table 1;ii) Exhibit D1/Tab 3/Schedule 1/Page 5/Table 3

a) Provide an update to the Bridge year 2010 forecast in Tables 1 and 3. Add a column for latest YTD.
b) Provide Explanation for all material variances in 2010 CAPEX Spend, including the revised completion in service dates.
c) Provide an estimate of the impact of the change in 2010 spend and timing on the 2011 capital additions and 2011 Revenue Requirement.
d) Discuss the impact of delays and under-spending in 2010 on the 2011 and 2012 capital program and provide an updated estimate of capital additions in each test year.

Response

a) The 2010 bridge year forecast remains as provided in Exhibit D1, Tab 3, Schedule 1. Please see the updates to the 2010 June YTD Actual in Tables 1 and 3.

Table 1 (Revised)
Summary of Transmission Capital Budget ($ Million)
Including Capitalized Overheads and AFUDC

Description	Historic			Bridge	Test		
	2007	2008	2009	2010	2011	2012	2010 June YTD Actual
Sustaining	210.0	280.4	300.0	308.3	424.0	443.4	172.4
Development	272.6	310.9	516.2	537.9	617.2	456.8	210.6
Operations	4.7	23.1	20.0	10.1	44.3	57.4	3.0
Shared Services Capital	72.2	89.8	81.5	73.6	66.3	50.6	17.8
TOTAL	**559.5**	**704.2**	**917.8**	**930.0**	**1,151.8**	**1,008.3**	**403.8**

Table 3 (Revised)
2010 Board Approved versus 2010 Projected Capital Expenditures ($ Million)

Capital Category	2010 Board Approved	2010 Bridge Year	Variance	2010 June YTD Actual
Sustaining	321.6	308.3	(13.3)	172.4
Development	642.3	537.9	(104.4)	210.6
Operations	28.9	10.1	(18.8)	3.0
Shared Services	64.9	73.6	8.7	17.8
Total	**1,057.6**	**930.0**	**(127.6)**	**403.8**

b) Please see Exhibit D1, Tab 3, Schedule 1Page 5 for an explanation of variance of Board approved versus Bridge year forecast.

c) N/A

d) N/A

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #43 List 1

Interrogatory

Issue 4.1: Are amounts proposed in rate base in 2011 and 2012 appropriate?
Issue 4.2 Are the proposed 2011 and 2012 Sustaining and Development and Operations capital expenditures appropriate, including consideration of factors such as system reliability and asset condition?

Reference: Exhibit D1/Tab 3/Schedule 2 Table 5

a) With regard to S16 explain the need and rationale for purchasing spare transformers.
b) Indicate the current inventory value of both spare and other transformers scheduled to be installed under the 2011/2012 capital program.
c) Discuss the logistics of moving spare transformers and placing these in service.
d) Discuss the regulatory treatment of these transformers including if they are additions to inventory and/or how the costs are to be recovered if the units are not in service.

Response

a) The rationale for purchasing these assets is described at Exhibit D, Tab 3, Schedule 2, page 21: "Insufficient numbers of spares will put the system and customers at risk as a result of loss of redundancy should a transformer fail without the availability of a spare. In addition, under these conditions maintenance will suffer as planned outage restrictions will have to be placed on equipment remaining in-service. This will result in possible equipment damage, a reduction in service life and possible system outages that will create difficult situations for LDC customers, as they may be required to shift load with possible temporary provisions to maintain customer supply." Many of the LDCs do not have adequate ability to shift load should the remaining in-service transformer fail, thereby exposing customers to outages that would be in the order of days to possibly weeks. Hydro One's fleet of spare transformers protects against a catastrophic event such as this.

   The planned acquisitions ensure that a sufficient fleet of spare transformers is available to support demand replacements.

b) The transformers which are scheduled to be installed under Sustaining and Development capital programs do not come from the fleet of spare transformers, but instead are ordered directly from Hydro One's suppliers and charged to the capital project. Spares are utilized to support demand replacements which occur due to equipment failure. On average there are two transformer demand replacements per year.

c) When an in-service transformer fails, Hydro One makes a case-by-case assessment if the faulted transformer can be repaired on-site, or if it must be removed and replaced with a spare transformer. Once the decision is made to utilize the spare, the transformer undergoes the process noted below. Note that due to the size and weight of the individual transformers they typically have to be transported disassembled to the stations where they will be installed.

- Transformer is prepared for deployment from Central Maintenance Services in Pickering;
  - Removal of the oil from the main tank (with exception of station service and possibly 42MVA transformers)
  - Obtaining transportation clearances and permits by either rail or road
  - Arrange the transportation of the accessories by truck (radiators, bushings, etc.)
- The transformer is shipped to site disassembled (with the exception of station service transformers and possibly 42MVA transformers);
- Transformer is assembled on-site and filled with oil
- Commissioning checks and testing are completed. Transformer is placed on potential for 24 hours. Final oil samples are taken to verify healthy condition and the transformer is placed in-service from an operational perspective.

It should be noted that the spare transformer is already considered in-service for financial and regulatory purposes, as it is considered an in-service fixed asset upon receipt.

d) Hydro One Transmission’s accounting policy for spare/reserve station and power transformers is to account for them as in-service fixed assets upon receipt, even though they have not yet been physically installed. This is because these assets provide current-period benefit to customers by providing them with increased assurance of system reliability. This accounting policy and regulatory treatment is consistent with the regulatory guidance for spare transformers found within articles 410, 420 and 510 of the Board’s Accounting Procedures Handbook for Electric Distribution Utilities, which is applied to the Company’s Transmission Business by analogy.

<u>Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #44 List 1</u>

Interrogatory

Issue 4.1: Are amounts proposed in rate base in 2011 and 2012 appropriate?
Issue 4.2 Are the proposed 2011 and 2012 Sustaining and Development and Operations capital expenditures appropriate, including consideration of factors such as system reliability and asset condition?

Reference: Exhibit D1/Tab 3/Schedule 4/Page 2 Table 1.

a) Provide details of the Wide Area Network project including when approved, capital expenditures cash flow and in-service dates.

Response

a) Please refer to Exhibit I, Tab 1, Schedule 87, part (a). The bridge and test years capital expenditure cash flows are per the table below.

$M	2010	2011	2012
Capital* and MFA	1.0	11.0	26.1
OM&A and Removals	0.0	0.0	0.0
Gross Investment Cost*	1.0	11.0	25.6
Recoverable	0.0	0.0	0.0
Net Investment Cost	1.0	11.0	26.1

The project will be placed in service in stages as portions of the network are completed; as such there will be in-service dates in each of years following 2010. The project continues beyond the test years.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #45 List 1

Interrogatory

Issue 4.1: **Are amounts proposed in rate base in 2011 and 2012 appropriate?**
Issue 4.2 **Are the proposed 2011 and 2012 Sustaining and Development and Operations capital expenditures appropriate, including consideration of factors such as system reliability and asset condition?**

Reference: Exhibit D2/Tab 1/Schedule 1/Page 1

a) Provide a version of D2/1/1 that shows the Historic and Bridge year data.

Response

a)

Hydro One Networks Inc.
Transmission
Statement of Utility Rate Base
($millions)

Particulars	2007 Actuals	2008 Actuals	2009 Actuals	2010 Forecast
Gross plant at cost	$9,948.6	$10,292.6	$10,781.3	$11,477.5
Less: accumulated depreciation	($3,648.2)	($3,765.4)	($3,966.6)	($4,188.8)
Net utility plant	$6,300.4	$6,527.2	$6,814.7	$7,288.7
Working Capital				
Cash Working capital [1]	$12.5	$11.3	$9.4	$8.6
Material and Supplies Inventory	$27.7	$10.5	$11.7	$12.7
Total Working Capital	$40.2	$21.8	$21.1	$21.3
Total Rate Base	$6,340.6	$6,549.0	$6,835.8	$7,310.0

[1] Hydro One Transmission does not calculate actual cash working capital, thus approved amounts have been provided for illustrative purposes.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #46 List 1

Interrogatory

Issue 4.1: **Are amounts proposed in rate base in 2011 and 2012 appropriate?**
Issue 4.2 **Are the proposed 2011 and 2012 Sustaining and Development and Operations capital expenditures appropriate, including consideration of factors such as system reliability and asset condition?**

Reference: Exhibit D2, Tab 2, Schedule 2 and Schedule 3

a) Please confirm that all eight Inter-Area Network Transfer Capability projects are aimed at increasing the capability of the transmission system to transport the increased generation output from specific areas of the province.
b) Based on the nature of the generation being supported please discuss the anticipated loading on the related transmission facilities associated with each project over the different months of the year and during the hours within each month.

Response

a) All eight Inter-Area Network Transfer Capability projects are aimed at increasing the capability of the transmission system to transport the increased generation output from specific areas of the province.

b) The transmission utilization and loading scenarios for Project D1 was discussed extensively in the Bruce to Milton transmission line section 92 (Leave to Construction) application. Please refer to proceeding in EB-2007-0050.

The Projects D2 to D8 are all shunt reactive compensation facilities and are intended to provide system voltage support. These are not transmission facilities that carry power flow similar to other transmission elements such as circuits, transformers or bus conductors. This question cannot be answered without more specific information on what transmission facilities (e.g. circuits or transformers) the loading assessments are being requested for. More specific information is also required regarding the type and location of the new generation that will be connected as well as the scenario assumptions on the existing resources that affect the facilities to be assessed.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #47 List 1

Interrogatory

(Issues 4.2 and 9.1)

References: i) Exhibit D2/Tab 2/Schedule 1Pages 1-2
ii) Exhibit D2/Tab 2/Schedule2/Pages 1

a) Provide a version of the Net Capital Expense Table that extracts for each major category, the "Government Instruction Capital and displays this as a separate Subtotal line and provide a new line for Total CAPEX.
b) Provide an annotation that shows which projects are GEGEA/Government instruction projects.
c) Reconcile the total GEGEA costs 2010-2012 indicated in part c) with the response to part a).

Response

a) Please see Attachment 1.

b) Please see Attachment 2.

c) Please refer to Attachment 1, page 2 line items "Total Development (Government Instructed)" and "Total Development (Non Government Instructed)" and compare to Attachment 2, page 5 line items "Total Development Capital (Government Instructed)" and "Total Development (Non Government Instructed)". Note: The total net expenditure for Development Capital for the test years 2011 and 2012 is as follows:

	2011 ($M)	**2012 ($M)**
Total Net Development	**617.2**	**456.8**
Government Instructed	*126.7*	*198.1*
Non Government Instructed	*490.4*	*258.7*

EB-2010-0002 – EXHIBIT D2, TAB 2, SCHEDULE 1 COMPARISON OF NET CAPITAL EXPENSE BY MAJOR CATEGORY

COMPARISON OF NET CAPITAL EXPENSE BY MAJOR CATEGORY

	Historic			Bridge	Test	
	2007	**2008**	**2009**	**2010**	**2011**	**2012**
<u>Transmission Capital ($ millions)</u>						
Sustaining						
Transmission Stations						
Circuit Breakers	0.6	11.6	16.6	30.8	23.6	24.9
Station Reinvestment	48.9	71.1	34.6	16.8	84.0	84.7
Power Transformers	18.7	40.7	48.7	71.3	63.5	65.7
Other Power Equipment	11.5	9.0	13.1	15.4	19.6	21.2
Ancillary Systems	8.9	9.9	6.0	9.1	18.0	18.1
Stations Environment	5.9	6.2	3.0	2.8	8.4	8.5
Protection, Control, Monitoring, and Telecommunications	44.1	55.2	82.0	72.5	93.8	107.5
Transmission Site Facilities and Infrastructure	4.0	20.3	20.1	23.1	26.5	26.4
Total Transmission Stations Capital	142.7	223.9	224.1	241.8	337.3	357.0
Transmission Lines						
Overhead Lines Refurbishment and Component Replacement	46.4	44.0	56.8	54.9	55.6	57.6
Transmission Lines Reinvestment	6.2	7.3	15.2	9.8	8.9	7.3
Underground Lines Cable Refurbishment & Replacement	14.6	5.3	4.1	1.9	22.2	21.6
Total Transmission Lines Capital	67.2	56.5	76.0	66.6	86.7	86.5
Total Sustaining Capital	210.0	280.4	300.1	308.3	424.0	443.4

	Historic			Bridge	Test	
	2007	2008	2009	2010	2011	2012
Development						
Inter Area Network Transfer Capability	**80.5**	**152.6**	**343.1**	**424.5**	**307.9**	**139.3**
Government Instructed	*0.0*	*0.0*	*0.0*	*0.0*	*4.5*	*22.6*
Non Government Instructed	*80.5*	*152.6*	*343.1*	*424.5*	*303.4*	*116.7*
Local Area Supply Adequacy	**97.4**	**91.0**	**93.7**	**61.9**	**150.5**	**101.4**
Government Instructed	*0.0*	*0.0*	*0.3*	*5.0*	*77.1*	*58.1*
Non Government Instructed	*97.4*	*91.0*	*93.4*	*56.9*	*73.4*	*43.3*
Load Customer Connection	**53.7**	**46.8**	**54.4**	**31.9**	**81.8**	**84.7**
Government Instructed	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
Non Government Instructed	*53.7*	*46.8*	*54.4*	*31.9*	*81.8*	*84.7*
Generator Customer Connection	**38.4**	**17.6**	**4.5**	**0.0**	**0.0**	**0.0**
Government Instructed	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
Non Government Instructed	*38.4*	*17.6*	*4.5*	*0.0*	*0.0*	*0.0*
Performance Enhancement & Risk Mitigation	**2.5**	**2.9**	**19.2**	**17.5**	**24.0**	**7.2**
Government Instructed	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
Non Government Instructed	*2.5*	*2.9*	*19.2*	*17.5*	*24.0*	*7.2*
TS Upgrades to Facilities Distribution Generation	**0.0**	**0.0**	**0.2**	**0.0**	**33.8**	**81.4**
Government Instructed	*0.0*	*0.0*	*0.2*	*0.0*	*33.8*	*81.4*
Non Government Instructed	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
P&C Enablement for Generation Connections	**0.0**	**0.0**	**0.9**	**0.6**	**11.4**	**36.0**
Government Instructed	*0.0*	*0.0*	*0.9*	*0.6*	*11.4*	*36.0*
Non Government Instructed	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
Smart Grid	**0.0**	**0.0**	**0.4**	**1.4**	**7.8**	**6.8**
Government Instructed	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
Non Government Instructed	*0.0*	*0.0*	*0.4*	*1.4*	*7.8*	*6.8*
Total Development	**272.6**	**310.9**	**516.2**	**537.9**	**617.2**	**456.8**
Total Development (Government Instructed)	***0***	***0***	***0.3***	***5.6***	***126.8***	***198.1***
Total Development (Non Government Instructed)	***272.6***	***310.9***	***515.9***	***532.3***	***490.4***	***258.7***

	Historic			Bridge	Test	
	2007	**2008**	**2009**	**2010**	**2011**	**2012**
Operations						
Grid Operating and Control Facilities	2.0	16.8	11.3	8.8	22.6	18.5
Operating Infrastructure	2.7	6.3	8.7	1.4	21.7	38.9
Total "Operations"	4.7	23.1	20.0	10.1	44.3	57.4
Shared Services and Other Costs						
Transport, Work & Service Equipment	13.3	17.5	14.0	19.8	21.6	17.0
Information Technology	13.3	9.2	9.2	17.0	18.9	14.4
Cornerstone	35.2	59.1	50.9	11.1	2.0	0.2
Facilities & Real Estate	3.2	3.5	6.3	25.8	23.9	19.1
Other	7.1	0.5	1.1	0.0	0.0	0.0
Total Shared Services & Other Costs	72.2	89.8	81.5	73.6	66.3	50.6
Total Transmission Capital	**559.5**	**704.2**	**917.8**	**930.0**	**1,151.8**	**1,008.3**

EB-2010-0002 – EXHIBIT D2, TAB 2, SCHEDULE 2 LIST OF CAPITAL INVESTMENT REQUIRING IN EXCESS OF $3 MILLION IN TEST YEAR 2011 OR 2012

LIST OF CAPITAL INVESTMENT PROGRAMS OR PROJECTS REQUIRING IN EXCESS OF $3 MILLION IN TEST YEAR 2011 OR 2012 ($ MILLIONS)

1.0 SUSTAINING CAPITAL (EXHIBIT D1, TAB 3, SCHEDULE 2)

1.1 Stations

		2011	2012
S1	2011/2012 Oil Circuit Breaker Replacement Program	6.9	7.9
S2	2011/2012 SF6 Breakers Type SP Replacements	13.2	13.4
S3	2011/2012 Metalclad Circuit Breakers Replacement - GTA	10.5	10.7
S4	Beck #1 SS: Air Blast Circuit Breaker (ABCB) Re-Investment	25.5	20.6
S5	Abitibi Canyon Switching Station (SS) and Pinard Transformer Station (TS) - Replace EOL Components	10.3	10.3
S6	Nanticoke TS: Air Blast Circuit Breaker (ABCB) Re-Investment	4.3	0
S7	Orangeville TS: Air Blast Circuit Breaker (ABCB) Re-Investment	10.3	10.6
S8	Richview TS 230 kV Switchyard: Air Blast Circuit Breaker (ABCB) Re-Investment	5.1	10.3
S9	Hanmer TS 500 kV ABCB Replacement	8.4	8.5
S10	Pickering A switchyard : Air Blast Circuit Breaker (ABCB) Re-Investment	3.2	3.3
S11	Merival GIS ITE Bus Replacement	6.3	6.4
S12	N.R.C Transmission Station	0	4.0
S13	Richview TS - Replace EOL Transformers T7/T8	6.4	2.8
S14	Replace EOL CGE Transformers	31.8	34.4
S15	Leaside TS - Replace EOL Transformers T19, T20 and T21	4.9	6.5
S16	Purchase Spare Transformers	13.2	13.3
S17	2011/2012 Station HV Disconnect replacement Program	5.1	5.2
S18	Capacitor Bank Replacement	3.1	3.3
S19	2011/2012 Station Service Upgrades	11.6	11.8
S20	2011/2012 Spill Containment Refurbishment - Major	8.4	8.5
S21	BSPS Replacement of End-of-Life Equipment	7.6	11.1

Note 1: GEGEA/Government Instructed project.

S22	ITC - Line Protections Replacements	4.8	4.9
S23	NYPA Tie Lines - Beck Line Protections Replacements	3.2	3.5
S24	2011 - 2012 Station P&C Replacement	22.0	22.2
S25	2011-2012 Protection Replacements	8.1	11.8
S26	2011-2012 RTU Replacement	5.0	5.5
S27	DC Signaling (Remote Trip) Replacements	7.0	6.4
S28	DC Signaling Replacements (Toronto North & East)	3.3	8.1
S29	NPCC Regulated Lines - Tone Equipment Replacements	5.6	8.2
S30	PLC Replacement Program	3.2	2.2
S31	TDCN Cyber Security	5.3	5.1
S32	2011/2012 Spill - Major Drainage	4.3	4.4
S33	Station Security Infrastructure	8.3	8.5

1.2 Lines

		2011	**2012**
S34	2011/2012 Transmission Wood Pole Replacement Program	30.8	31.3
S35	2011/2012 Steel Structure Coating Program	5.5	6.5
S36	2011/2012 Shieldwire Replacement Program	4.2	4.3
S37	2011/2012 Transmission Lines Emergency Restoration	6.6	6.6
S38	Circuit A6P - Reserve Jct. to Port Arthur TS Transmission Line Refurbishment	7.1	6.2
S39	H2JK / K6J Cable Replacement (Riverside Jct. x Strachan TS)	20.6	20.0

Summary – Sustainment	**2011**	**2012**
Total Sustaining Projects & Programs Listed Above	**351.0**	**368.4**
Sustaining Projects & Programs Less than $3 M	**73.0**	**75.0**
Total Sustaining Capital (per Exhibit D1-3-2)	**424.0**	**443.4**

2.0 DEVELOPMENT CAPITAL (EXHIBIT D1, TAB 3, SCHEDULE 3)

2.1 Inter-Area Network Transfer Capability

		2011	2012
D1	New 500 kV Bruce to Milton Double Circuit Transmission Line4	184.4	94.3
D2	Northeast Transmission Reinforcement: Install SVC's at Porcupine TS & Kirkland Lake TS	33.1	0
D3	Nanticoke TS - Install 500 kV, 350 MVar Static Var Compensator	22.1	0
D4	Detweiler TS - Install 230 kV, 350 MVar Static Var Compensator	34.9	0
D5	Essa TS - Install 250 MVar Shunt Capacitor Bank	5.9	0
D6	Porcupine TS - Install two100 MVar Shunt Capacitor Banks	10.3	0.2
D7	Hanmer TS - Install 149 MVar Shunt Capacitor Bank	7.9	0.1
D8	Dryden TS - Install a Shunt Capacitor Bank	0.1	10.3

2.2 Local Area Supply Adequacy

		2011	2012
D9	Woodstock Area Transmission Reinforcement	20.7	0
D10	Rebuild Burlington TS 115kV Switchyard	30.4	1.4
D11	Toronto Area Station Upgrades for Short Circuit Capability: Re-build Hearn SS ***(Note 1)***	**54.6**	**27.0**
D12	Toronto Area Station Upgrades for Short Circuit Capability: Lea-side TS Equipment Uprate ***(Note 1)***	**13.5**	**21.9**
D13	Toronto Area Station Upgrades for Short Circuit Capability: Manby TS Equipment Uprate ***(Note 1)***	**9.0**	**9.2**
D14	Midtown Transmission Reinforcement Plan	31.0	36.7
D15	Guelph Area Transmission Reinforcement	1.0	4.1

2.3 Load Customer Connection

		2011	2012
D16	Commerce Way TS: Build new TS and Line Connection (for-merly Woodstock East TS)	27.1	6.5
D17	Kirkland Lake TS: Reconnect Idle K4 Line	13.3	0.2
D18	South Halton Tremaine TS: Build New Transformer Station	20.9	5.5
D19	Ancaster TS: Build new Transformer Station and Line Connection	3.4	17.0
D20	East Ottawa TS: Build new Transformer Station	3.6	21.3
D21	Leamington TS: New 230/27.6 kV DESN and Line Connection	15.4	33.8

Note 1: GEGEA/Government Instructed project.

D22	New 230/28 kV Transformer Station in Northern Mississauga & Line Connection	0.1	7.4
D23	Enfield TS: Build 230/44 kV DESN and Line Connection (formally Oshawa Area TS)	0	4.9
D24	Long Lac TS: Replace End-of-Life 115-44 kV Transformers	5.3	0
D25	North Bay TS: Upgrade to a 115-44 kV Transformer Station	18.3	8.4
D26	Barwick TS: Build new Transformer Station	8.8	6.2
D27	Duart TS: Build new Transformer Station and Line Connection (formerly Rodney TS)	12.1	12.6

2.4 Generation Customer Connection

		2011	**2012**
D28	500 MW Renewables III RFP (Talbot Wind Farm)	23.0	0
D29	350 MW Peaking Generation in Northern York Region	4.5	0
D30	Chatham Wind Generation Connection (260MW)	0.1	4.1
D31	Lower Mattagami Generation Connections	2.0	4.0

2.5 Enabling Facilities (Government Instruction)

		2011	**2012**
D32	Enabling 230/44kV TS #1 and Short (<2km) Tap ***(Note 1)***	**0.05**	**8.4**
D33	Enabling 115/44kV TS #1 and Short (<2km) Tap ***(Note 1)***	**0.05**	**8.4**

2.6 Bulk & Regional Transmission (Government Instruction)

		2011	**2012**
D34	Algoma x Sudbury Transmission Expansion ***(Note 1)***	**0**	**5.7**
D35	Northwest Transmission Reinforcement ***(Note 1)***	**4.5**	**16.9**

2.7 Station Equipment Upgrades & Additions to Facilitate Renewables (Government Instruction)

		2011	**2012**
D36	Static Var Compensator #1 at Existing Station in South Western Ontario ***(Note 1)***	**0.4**	**32.9**
D37	In-Line Circuit Breakers #1 ***(Note 1)***	**13.4**	**6.9**
D38	In-Line Circuit Breakers #2 ***(Note 1)***	**13.4**	**6.9**
D39	In-Line Circuit Breakers #3 ***(Note 1)***	**3.2**	**7.2**
D40	In-Line Circuit Breakers #4 ***(Note 1)***	**3.2**	**7.2**
D41	In-Line Circuit Breakers #5 ***(Note 1)***	**0**	**1.2**
D42	In-Line Circuit Breakers #6 ***(Note 1)***	**0**	**1.2**

2.8 Protection and Control for Enablement of Distribution Connected Generation (Government Instruction)

		2011	2012
D43	Station Protection Upgrades for Distributed Generation ***(Note 1)***	**5.3**	**15.8**
D44	Transfer Trip Facilities ***(Note 1)***	**4.7**	**14.0**

2.9 Smart Grid

		2011	2012
D45	End-to End Testing of Interoperable Bus Architecture at Owen Sound and Meaford Transformer Stations	5.5	5.5

2.10 Performance Enhancement

		2011	2012
D46	Various lines and TSs outliers-inliers	4.0	4.0

2.11 Risk Mitigation

		2011	2012
D47	Mitigate Reliability Problems of HV Shunt Capacitor Installations	16.8	0.0

Summary – Development	2011	2012
Total Development Projects & Programs Listed Above	**701.7**	**490.4**
Government Instructed	**125.3**	**190.8**
Non Government Instructed	**576.4**	**299.6**
Development Projects & Programs Less than $3 M	**21.5**	**44.3**
Government Instructed	**1.4**	**7.3**
Non Government Instructed	**20.1**	**37.0**
Less Capital Contribution	**(106.1)**	**(77.9)**
Government Instructed	**0**	**0**
Non Government Instructed	**(106.1)**	**(77.9)**
Total Development Capital (per Exhibit D1-3-3)	**617.2**	**456.8**
Government Instructed	**126.7**	**198.1**
Non Government Instructed	**490.4**	**258.7**

Note 1: GEGEA/Government Instructed project.

3.0 OPERATIONS CAPITAL (EXHIBIT D1, TAB 3, SCHEDULE 4)

3.1 Grid Operations Control Facilities

		2011	2012
O1	Network Operations Buildings	12.1	11.0
O2	NMS Upgrade & Enhancements	3.8	4.0
O3	Tx Operating Facilities Sustainment	6.5	3.5

3.2 Operating Infrastructure

		2011	2012
O4	Hub Site Management Program	2.9	4.3
O5	Telemetry Expansion	3.4	3.5
O6	Wide Area Network	11.0	26.1

Summary – Operations	**2011**	**2012**
Total Operations Projects & Programs Listed Above	**39.7**	**52.4**
Operations Projects & Programs Less than $3 M	**4.6**	**5.0**
Total Operations Capital (per Exhibit D1-3-4)	**44.3**	**57.4**

4.0 SHARED SERVICES AND OTHER CAPITAL (EXHIBIT D1, TAB 3, SCHEDULE 5)

4.1 Information Technology

		2011	2012
IT1	Cornerstone Phase 2	-	-
IT2	Cornerstone Phase 3	20.8	29.3
IT3	Mobile IT Platform	3.0	2.0
IT4	GIS Implementation	6.0	4.9
IT5	MFA PC and Printer Hardware	6.2	4.2
IT6	Software Refresh & Maintenance - Enterprise Application Software	3.2	3.6
IT7	MFA UNIX Servers	4.1	4.2
IT8	MFA Windows Servers	3.5	1.9

4.2 Other

		2011	2012
C1	Real Estate Facilities Capital for 2011 and 2012	25.8	19.6
C2	Real Estate Head Office and GTA Facilities Capital for 2011 and 2012	19.0	15.6
C3	Shared Services Capital – Service Equipment	8.8	5.9
C4	Shared Services Capital – Transport & Work Equipment	74.1	60.2

Summary - Shared Services and Other Capital	**2011**	**2012**
Total Shared Services, Other Projects & Programs listed above	**174.5**	**151.4**
Shared Services, Other Projects & Programs less than $3 M	**11.9**	**8.3**
Less Cornerstone Savings	**(13.9)**	**(22.1)**
Total Shared Services & Other Capital (per Exhibit D1-3-5)	**172.5**	**137.6**
Transmission allocation of Shared Services & Other Capital (per Exhibit D1, Tab 3)	**66.3**	**50.6**

Note 1: GEGEA/Government Instructed project.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #48 List 1

Interrogatory

Issue 5.3: Is the forecast of long term debt for 2010-2012 appropriate?

References: i) Exhibit B1/Tab 2/Schedule 1Table 4;
ii) Exhibit B2/Tab 1Schedule 2/Page 4

a) For historical 2009 and bridge year 2010 debt (listed in B1/2/1 Table 4) and B2/1/2 page 4 at lines 23-31 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-2008-0272
   ii. Coupon rate forecast approved by the Board
   iii. The premium discount and expenses
   iv. the total principal amount
   v. the annual carrying cost

b) For material differences in the schedule 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 2009 issue details are shown on lines 25 to 27 of page 1, Exhibit 1.4.1, EB-2008-0272 Rate Order. Actual issue details for 2009 are shown on lines 27 to 29 of page 3 Exhibit B2, Tab 1, Schedule 2 EB-2010-0002.

   Board approved 2010 issue details are shown on lines 23 to 28 of page 1, Exhibit 1.4.2, EB-2008-0272 Rate Order. Actual and current assumption issue details for 2010 are shown on lines 23 to 31 of page 4 Exhibit B2, Tab 1, Schedule 2 EB-2010-0002.

b) There is no material difference in the overall rate contained in the schedules.

EXHIBIT 1.4.1 – EB-2008-0272 RATE ORDER, JUNE 11, 2009
&
EXHIBIT B2, TAB 1, SCHEDULE 2 – EB-2008-0272

HYDRO ONE NETWORKS INC.
TRANSMISSION
Cost of Long-Term Debt Capital
Test Year (2009) Updated for 2008 Actuals
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 $100 Principal Amount (Dollars)	Effective Cost Rate	Total Amount Outstanding: at 12/31/08 ($Millions)	Total Amount Outstanding: at 12/31/09 ($Millions)	Avg. Monthly Averages ($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-10	278.4	3.6	274.8	98.70	7.34%	278.4	278.4	278.4	20.4	
2	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	
3	22-Jun-01	6.400%	1-Dec-11	174.0	(0.5)	174.5	100.28	6.36%	174.0	174.0	174.0	11.1	
4	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	
5	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	
6	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	
7	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	
8	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	
9	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	
10	24-Feb-04	3.950%	24-Feb-09	162.5	0.7	161.8	99.55	4.05%	162.5	0.0	25.0	1.0	
11	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	
12	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	
13	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	
14	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	
15	19-May-05	3.950%	24-Feb-09	105.0	(0.9)	105.9	100.90	3.69%	105.0	0.0	16.2	0.6	
16	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	
17	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	
18	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	
19	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	
20	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	
21	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	
22	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	
23	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	
24	19-Nov-08	3.890%	19-Nov-10	60.0	0.1	59.9	99.78	4.01%	60.0	60.0	60.0	2.4	
25	15-Mar-09	5.770%	15-Mar-39	337.0	1.7	335.3	99.50	5.81%	0.0	337.0	259.2	15.0	
26	15-Jun-09	5.070%	15-Jun-19	337.0	1.7	335.3	99.50	5.13%	0.0	337.0	181.5	9.3	
27	15-Sep-09	4.380%	15-Sep-14	337.0	1.7	335.3	99.50	4.49%	0.0	337.0	103.7	4.7	
28		**Subtotal**							3524.0	4267.5	3842.0	221.8	
29		Treasury OM&A costs										1.9	
30		Other financing-related fees										0.8	
31		**Total**							3524.0	4267.5	3842.0	224.5	5.8437%

HYDRO ONE NETWORKS INC.
TRANSMISSION
Cost of Long-Term Debt Capital
Test Year (2010) Updated for 2008 Actuals
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 $100 Principal Amount (Dollars)	Effective Cost Rate	Total Amount Outstanding: at 12/31/09 ($Millions)	Total Amount Outstanding: at 12/31/10 ($Millions)	Avg. Monthly Averages ($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-10	278.4	3.6	274.8	98.70	7.34%	278.4	0.0	128.5	9.4	
2	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	
3	22-Jun-01	6.400%	1-Dec-11	174.0	(0.5)	174.5	100.28	6.36%	174.0	174.0	174.0	11.1	
4	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	
5	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	
6	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	
7	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	
8	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	
9	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	
10	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	
11	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	
12	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	
13	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	
14	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	
15	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	
16	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	
17	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	
18	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	
19	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	
20	3-Mar-08	5.180%	18-Oct-17	180.0	(3.1)	183.1	101.74	4.95%	180.0	180.0	180.0	8.9	
21	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	
22	19-Nov-08	3.890%	19-Nov-10	60.0	0.1	59.9	99.78	4.01%	60.0	0.0	50.8	2.0	
23	15-Mar-09	5.770%	15-Mar-39	337.0	1.7	335.3	99.50	5.81%	337.0	337.0	337.0	19.6	
24	15-Jun-09	5.070%	15-Jun-19	337.0	1.7	335.3	99.50	5.13%	337.0	337.0	337.0	17.3	
25	15-Sep-09	4.380%	15-Sep-14	337.0	1.7	335.3	99.50	4.49%	337.0	337.0	337.0	15.1	
26	15-Mar-10	6.870%	15-Mar-40	170.4	0.9	169.6	99.50	6.91%	0.0	170.4	131.1	9.1	
27	15-Jun-10	6.170%	15-Jun-20	170.4	0.9	169.6	99.50	6.24%	0.0	170.4	91.8	5.7	
28	15-Sep-10	5.480%	15-Sep-15	170.4	0.9	169.6	99.50	5.60%	0.0	170.4	52.4	2.9	
29		**Subtotal**							4267.5	4440.3	4383.6	249.5	
30		Treasury OM&A costs										2.0	
31		Other financing-related fees										0.8	
32		**Total**							4267.5	4440.3	4383.6	252.3	5.7556%

HYDRO ONE NETWORKS INC.
TRANSMISSION
Cost of Long-Term Debt Capital
Historical Year (2009)
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 $100 Principal Amount (Dollars)	Effective Cost Rate	Total Amount Outstanding: at 12/31/08 ($Millions)	Total Amount Outstanding: at 12/31/09 ($Millions)	Avg. Monthly Averages ($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-10	278.4	3.6	274.8	98.70	7.34%	278.4	278.4	278.4	20.4	
2	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	
3	22-Jun-01	6.400%	1-Dec-11	174.0	(0.5)	174.5	100.28	6.36%	174.0	174.0	174.0	11.1	
4	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	
5	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	
6	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	
7	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	
8	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	
9	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	
10	24-Feb-04	3.950%	24-Feb-09	162.5	0.7	161.8	99.55	4.05%	162.5	0.0	25.0	1.0	
11	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	
12	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	
13	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	
14	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	
15	19-May-05	3.950%	24-Feb-09	105.0	(0.9)	105.9	100.90	3.69%	105.0	0.0	16.2	0.6	
16	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	
17	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	
18	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	
19	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	
20	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	
21	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	
22	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	
23	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	
24	19-Nov-08	3.890%	19-Nov-10	60.0	0.1	59.9	99.78	4.01%	60.0	60.0	60.0	2.4	
25	13-Jan-09	3.890%	19-Nov-10	65.0	(0.4)	65.4	100.67	3.51%	0.0	65.0	60.0	2.1	
26	14-Jan-09	5.000%	12-Nov-13	130.0	(3.7)	133.7	102.87	4.33%	0.0	130.0	120.0	5.2	
27	3-Mar-09	6.030%	3-Mar-39	195.0	1.2	193.8	99.43	6.07%	0.0	195.0	150.0	9.1	
28	16-Jul-09	5.490%	16-Jul-40	210.0	1.3	208.7	99.37	5.53%	0.0	210.0	96.9	5.4	
29	19-Nov-09	3.130%	19-Nov-14	175.0	0.6	174.4	99.64	3.21%	0.0	175.0	26.9	0.9	
30		**Subtotal**							3524.0	4031.5	3709.9	213.4	
31		Treasury OM&A costs										1.2	
32		Other financing-related fees										1.2	
33		**Total**							3524.0	4031.5	3709.9	215.7	5.8148%

HYDRO ONE NETWORKS INC.
TRANSMISSION
Cost of Long-Term Debt Capital
Bridge Year (2010)
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 $100 Principal Amount (Dollars)	Effective Cost Rate	Total Amount Outstanding: at 12/31/09 ($Millions)	Total Amount Outstanding: at 12/31/10 ($Millions)	Avg. Monthly Averages ($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-10	278.4	3.6	274.8	98.70	7.34%	278.4	0.0	128.5	9.4	
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3	22-Jun-01	6.400%	1-Dec-11	174.0	(0.5)	174.5	100.28	6.36%	174.0	174.0	174.0	11.1	
4	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	
5	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	
6	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	
7	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	
8	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	
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17	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	
18	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	
19	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	
20	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	
21	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	
22	19-Nov-08	3.890%	19-Nov-10	60.0	0.1	59.9	99.78	4.01%	60.0	0.0	50.8	2.0	
23	13-Jan-09	3.890%	19-Nov-10	65.0	(0.4)	65.4	100.67	3.51%	65.0	0.0	55.0	1.9	
24	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	
25	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	
26	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	
27	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	
28	15-Mar-10	5.490%	16-Jul-40	120.0	(0.7)	120.7	100.59	5.45%	0.0	120.0	92.3	5.0	
29	15-Mar-10	4.400%	1-Jun-20	180.0	0.8	179.2	99.56	4.45%	0.0	180.0	138.5	6.2	
30	15-Jun-10	4.680%	15-Jun-20	100.0	0.5	99.5	99.50	4.74%	0.0	100.0	53.8	2.6	
31	15-Sep-10	3.560%	15-Sep-15	100.0	0.5	99.5	99.50	3.67%	0.0	100.0	30.8	1.1	
32		**Subtotal**							4031.5	4128.0	4177.7	231.3	
33		Treasury OM&A costs										2.0	
34		Other financing-related fees										5.0	
35		**Total**							4031.5	4128.0	4177.7	238.3	5.70%

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #49 List 1

Interrogatory

Issue 5.3: **Is the forecast of long term debt for 2010-2012 appropriate?**

References: i) Exhibit B1/Tab 1/Schedule 1, page 3
ii) Exhibit B2/Tab 1/Schedule 2/Page 5

a) Provide a schedule that sets out for B/1/2 page 6 lines 28-33 the basis of the proposed coupon rates, other financing costs and annual carrying costs for all proposed 2011/12 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
   iii. Sources and dates of forecast(s) other financing costs
b) Reconcile answer with Tables 3 and 4 of B1/2/1.
c) When will Hydro One provide an update of the forecast 2011/12 debt costs?
d) Explain in detail how the 2011/12 debt issues and costs are mapped to Hydro One Networks and to Hydro One Transmission.
e) Based on the 2011 and 2012 financing plan provide an estimate of the revenue requirement impact to Hydro One Networks transmission of a 10 basis point change in the average effective coupon rate.

Response

a) The long term forecast debt issuance set out in Exhibit B2, Tab 1, Schedule 2, Page 6 lines 28 – 33 is described in Exhibit B1, Tab 2, Schedule 1, Section 3.4, from line 5 of page 6 to line 11 of page 7.

b) It is the same.

c) Hydro One does not plan to update the forecast 2011 and 2012 debt costs.

d) Hydro One Networks Inc. issues debt to Hydro One Inc., reflecting debt issues by Hydro one Inc. to third party public debt investors. The portion of the debt issued by Hydro One networks Inc. that is mapped to the Transmission business is described in Exhibit B1, Tab 2, Schedule 1, page 2, lines 17 – 20.

e) Based on the 2011 and 2012 financing plan, the revenue requirement impact of a 10 basis point change in the average effective coupon rate is \$0.5M and \$1.3M in 2011 and 2012, respectively.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #50 List 1

Interrogatory

Issue 6.1: Are the proposed amounts, disposition and continuance of Hydro One's existing Deferral and Variance accounts appropriate?

References: i) Exhibit F1/Tab 2/Schedule 1/Page 1/Table 1;
ii) Exhibit F1/Tab2/Schedule/1Page 2/Table 2

a) Explain the use of different time frames for the disposition of the regulatory assets in Table 2 and why there should be a delay in disposing the IPSP and Other Long Term Planning and Pension Cost Differential.

Response

Hydro One is requesting disposition of negative regulatory asset balances over a twelve-month period, rather than a twenty-four month period, in order to mitigate rate impacts to customers in 2011. Where the regulatory asset is positive, Hydro One is requesting to recover the balance over twenty-four months for rate smoothing purposes.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #51 List 1

Interrogatory

Issue 6.1: Are the proposed new Deferral and Variance Accounts appropriate?

Reference: Exhibit A/Tab11/Schedule 3/pages1-9.

Preamble: The second exception described and for which a variance account is requested is for gains and losses on tangible and intangible asset sales or losses resulting from premature asset retirement in 2012.

a) If the requested variance account is approved by the Board, confirm that the account should be reduced by the amount of depreciation expense otherwise included in rates under the existing methodology.

Response

a) The Company agrees that the variance account should be credited for any depreciation expense in rates that is attributable to prematurely retired assets. The depreciation credit would be calculated based on amount of depreciation in approved revenue requirement that will not be incurred as a result of an asset premature retirement.

<u>Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #52 List 1</u>

<u>Interrogatory</u>

Issue 6.2: Are the proposed new Deferral and Variance Accounts appropriate?

Reference: Exhibit F1/Tab 1/Schedule 2/Page 2 IFRS - INCREMENTAL TRANSITION COSTS

a) Why does Hydro One require the continuing use of this account in 2011 and 2012, given that the implementation date for IFRS is January 2011?
b) Explain why Hydro One expects to incur incremental transition costs after the implementation date?

<u>Response</u>

For parts a) and b), please see Exhibit I, Tab 1, Schedule 92, part m.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #53 List 1

Interrogatory

Issue 6.2: Are the proposed new Deferral and Variance Accounts appropriate?

Reference: Exhibit F1/Tab 1/Schedule 2/Page 4 of 5

a) Why is it necessary to record the impact of HST in the Tax Rate Changes Account since the HST Tax Change will have occurred in 2010 and no new changes to the rate are contemplated?

Response

It is correct that the HST will take effect July 1, 2010 and no new change to the HST rate is currently contemplated. However, it is necessary to record the impact of the HST in the Tax Rate Changes Account because the current rate filing includes PST as part of the costs for the test years. As noted in Exhibit I, Tab 1, Schedule 91, part d, Hydro One is in the process of establishing the methodology that will capture the revenue requirement impact driven by the harmonization of the PST and GST in order to return the net savings to ratepayers in a future proceeding.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #54 List 1

Interrogatory

Issue 6.2: Are the proposed new Deferral and Variance Accounts appropriate?

Reference: Exhibit F1/Tab 1/Schedule 2

Preamble: This account will track the difference between the annual OEB Cost Assessments, intervenor cost awards, and costs associated with OEB-initiated studies and the amount for these expenditures approved by the OEB as part of 2011 and 2012 Transmission Rates.

a) Why should the OEB approve this account for Hydro One Networks, since a similar account was only approved for the period 2004-2006 for electricity distributors and the approval of the account in EB-2008-0272 was for variances in OEB Assessments only?

Response

a) Please see Exhibit I, Tab 1, Schedule 92, parts s to w inclusive.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #55 List 1

Interrogatory

Issue 7.1: Is the cost allocation proposed by Hydro One appropriate?

References: i) Exhibit G1, Tab 2, Schedule 1, pages 11-13
ii) Exhibit G2, Tab 2, Schedule 1

a) Please describe how the costs of a Dual Function Line with both load customers and generation customers connected to it will be allocated as between Network and Line Connection. Please provide an illustrative example.
b) What year's "customer demand" was used to determine the allocation percentages for Dual Function Line Assets?

Response

a) As per the methodology approved by the Board, and detailed in Exhibit G1, Tab 2, Schedule 1, page 11, the allocation of Dual Function Line (DFL) costs is based on the customer load connected to the DFL and the transmission capacity of the DFL. The amount of generation connected to a DFL does not impact the cost allocation.

b) The 2011 forecast annual average coincident peak demand of customer load was used to determine the allocation percentages for DFL assets.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #56 List 1

Interrogatory

Issue 7.1: Is the cost allocation proposed by Hydro One appropriate?

References: i) Exhibit G2, Tab 1, Schedule 1
ii) EB-2008-0272, Exhibit G2, Tab 1, Schedule 1

a) Please provide a listing of those transmission lines in this Schedule whose Functional Category designation has changed since EB-2008-0272 and provide explanations as to the reason for each change.
b) Please provide a schedule that lists the new Transmission Lines noted in Exhibit G2, Tab 1, Schedule 1 (i.e., not included in EB-2008-0272). In each case please indicate the relevant project reference number (from either the EB-2008-0272 Application or this Application) that describes the investment.

Response

a) There are 42 transmission line segments out of more than 2,300 line segments on the transmission system for which the functionalization has changed in EB-2010-0002 as compared to EB-2008-0272.

The reasons for the functionalization changes are mainly due to database clean-up and line segment reconfiguration, which includes the adding/removing of customer taps to/from an existing line segment.

Table 1 and 2 list the EB-2010-0002 line segments which have been changed. Table 1 shows the line segments used in both filings and their new and old functionalization assignments with the reason for each change. Table 2 shows the line segments that were renamed as a result of reconfiguration and whose functionalization changed as compared to EB-2008-0272.

Table 1: Line Segment New Rate Pool Assignments

Operation Designation	Section #	EB-2010-0002	EB-2008-0272	Explanation for the change
K6F	10	OTHER	TDF	Tap to Margach DS T2 was disconnected
A1T	5	OTHER	LC	25 Hz system in Niagara region was removed from service
A1T	6	OTHER	LC	25 Hz system in Niagara region was removed from service
A1T	11	OTHER	LC	25 Hz system in Niagara region was removed from service
A1T	12	OTHER	LC	25 Hz system in Niagara region was removed from service
A8G	1	OTHER	LC	25 Hz system in Niagara region was removed from service
A8G	2	OTHER	LC	25 Hz system in Niagara region was removed from service
A8G	3	OTHER	LC	25 Hz system in Niagara region was removed from service

Operation Designation	Section #	EB-2010-0002	EB-2008-0272	Explanation for the change
A8G	4	OTHER	LC	25 Hz system in Niagara region was removed from service
Q1N	1	OTHER	LC	25 Hz system in Niagara region was removed from service
Q5G	1	OTHER	LC	25 Hz system in Niagara region was removed from service
Q5G	2	OTHER	LC	25 Hz system in Niagara region was removed from service
Q5G	3	OTHER	LC	25 Hz system in Niagara region was removed from service
Q5G	4	OTHER	LC	25 Hz system in Niagara region was removed from service
B4V	1	DFL	N	Added customer tap to 'N' line
B5V	1	DFL	N	Added customer tap to 'N' line
B5V	2	DFL	N	Added customer tap to 'N' line
P1T	1	OTHER	LC	Change in operating configuration
P1T	2	OTHER	LC	Change in operating configuration
P1T	4	OTHER	LC	Change in operating configuration
C23Z	1	DFL	N	Added customer tap to 'N' line
C23Z	2	DFL	N	Added customer tap to 'N' line
C23Z	3	DFL	N	Added customer tap to 'N' line
C23Z	4	TDF	OTHER	Change in operating configuration
S7M	14	OTHER	LC	Change in operating configuration
V41N	1	DFL	N	Database clean up
V41N	2	TDF	LC	Database clean up
A9K	4	TDF	LC	Database clean up
D1W	1	TDF	LC	Database clean up
L27V	5	TDF	LC	Database clean up
S7M	6	LC	TDF	Database clean up
S7M	18	TDF	LC	Database clean up

Table 2: Line Segment New Names and Rate Pool Assignments

EB-2008-0272			EB-2010-0002			
Operation Designation	**Section #**		**Operation Designation**	**Section #**		**Reason for the Change**
V72RS	9	TDF	V41H	1	LC	Change in operating configuration
V73RS	1	DFL	V73R	4	N	Change in operating configuration
V73RS	3	TDF	V42H	2	LC	Change in operating configuration
V73RS	7	TDF	V42H	10	LC	Change in operating configuration
V73RS	10	DFL	V42H	1	LC	Change in operating configuration
V74R	4	TDF	V43	5	LC	Change in operating configuration
V75P	13	TDF	V44	1	LC	Change in operating configuration
V75P	18	OTHER	V77R	1	N	Change in operating configuration
V76R	6	TDF	V43	2	LC	Change in operating configuration
V76R	8	DFL	V43	1	LC	Change in operating configuration

b) There are 53 new transmission line segments noted in EB-2010-0002, Exhibit G2, Tab 1, Schedule 1. Table 3 lists the new line segments and project reference number, where appropriate.

Table 3: New Line Segment Rate Pool Assignments

Operation Designation	Section #	From	To	Functional Category	Explanation and or Project Reference #
15M1	13	Kenora MTS JCT	Kenora MTS JCT	LC	Change in operating configuration
15M1	15	Kenora MTS JCT	Kenora MTS	LC	Change in operating configuration
A2	8	Cyrville Rd JCT	Cyrville JCT	LC	EB-2008-0272, Ex. D1/T3/S3, Table 4 “Other Historical Projects”: Tap to customer owned Cyrville MTS
A2	9	Cyrville Rd JCT	Cyrville MTS	LC	EB-2008-0272, Ex. D1/T3/S3, Table 4 “Other Historical Projects”: Tap to customer owned Cyrville MTS
A4K	11	Cyrville Rd JCT	Cyrville JCT	LC	EB-2008-0272, Ex. D1/T3/S3, Table 4 “Other Historical Projects”: Tap to customer owned Cyrville MTS
A4K	12	Cyrville Rd JCT	Cyrville MTS	LC	EB-2008-0272, Ex. D1/T3/S3, Table 4 “Other Historical Projects”: Tap to customer owned Cyrville MTS
A5H	15	Fournier JCT	Fournier JCT	TDF	Database clean-up
B1	1	Beach Road JCT	Beach TS	LC	Database clean-up
B4V	5	Underwood JCT	Hanover TS	DFL	EB-2008-0272 Ex D1/T3/S3, Table 5 “Other Historical Projects”: Tap to customer owned Underwood CTS (Underwood Wind Farm)
B4V	6	Underwood JCT	Underwood CTS	TDF	EB-2008-0272 Ex D1/T3/S3, Table 5 “Other Historical Projects”: Tap to customer owned Underwood CTS (Underwood Wind Farm)
B5V	3	Underwood JCT	Hanover TS	DFL	EB-2008-0272 Ex D1/T3/S3, Table 5 “Other Historical Projects”: Tap to customer owned Underwood CTS (Underwood Wind Farm)
B5V	4	Underwood JCT	Underwood CTS	TDF	EB-2008-0272 Ex D1/T3/S3, Table 5 “Other Historical Projects”: Tap to customer owned Underwood CTS (Underwood Wind Farm)
B5V	5	Amaranth JCT	Orangeville TS	DFL	EB-2008-0272 Ex D1/T3/S3, Table 5 “Other Historical Projects”: Tap to customer owned Amaranth CTS (Melancthon II Wind)
B5V	6	Amaranth JCT	Amaranth CTS	TDF	EB-2008-0272 Ex D1/T3/S3, Table 5 “Other Historical Projects”: Tap to customer owned Amaranth CTS (Melancthon II Wind)
B82V	6	Holland JCT	Woodbridge JCT	DFL	EB-2008-0272 Ex. D2/T2/S2, Ref. #D24: Tap to Holland TS

Operation Designation	Section #	From	To	Functional Category	Explanation and or Project Reference #
B82V	7	Holland JCT	Holland TS	TDF	EB-2008-0272 Ex. D2/T2/S2, Ref. #D24: Tap to Holland TS
B83V	6	Holland JCT	Woodbridge JCT	DFL	EB-2008-0272 Ex. D2/T2/S2, Ref. #D24: Tap to Holland TS
B83V	7	Holland JCT	Holland TS	TDF	EB-2008-0272 Ex. D2/T2/S2, Ref. #D24: Tap to Holland TS
C3L	4	Leaside Str 4-5 JCT	Leaside TS	LC	Database clean-up
D9HS	8	Beach Road JCT	Beach TS	LC	Database clean-up
E8F	5	Ford Windsor MTS	East Windsor CGS	LC	EB-2008-0272 Ex D1/T3/S3, Table 5 “Other Historical Projects”: Tap to East Windsor CGS
E9F	5	Ford Windsor MTS	East Windsor CGS	LC	EB-2008-0272 Ex D1/T3/S3, Table 5 “Other Historical Projects”: Tap to East Windsor CGS
F11C	7	Freeport SS	Freeport SS	LC	Database clean-up
H3L	9	Gerrard TS	Bloor Street JCT	LC	EB-2008-0272 Ex. D2/T2/S2, Ref. #S36: U/G Cable Replacement
H9A	24	Gamble H9A JCT	Gamble H9A JCT	LC	Change in operating configuration
IDLE14	1	Beach TS	Beach STR 44 JCT	OTHER	Database clean-up
IDLE23	1	Nia Park EP J	Mid R. JCT Niagara	OTHER	Database clean-up
IDLE4	1	Birch JCT	Bridgman JCT	OTHER	Database clean-up
K12	1	Karn TS	Woodstock TS	LC	EB-2008-0272 Ex. D2/T2/S2, Ref. #D18: Woodstock Area Reinforcement
K3D	2	K3D-10 SW JCT	Vermilion Bay JCT	DFL	Database clean-up
K6F	7	Sioux Narrows JCT	K6F-10 SW JCT	DFL	Database clean-up
K7	1	Karn TS	Woodstock TS	LC	EB-2008-0272 Ex. D2/T2/S2, Ref. #D18: Woodstock Area Reinforcement
L1S	11	Milman Foundry JCT	Milman Foundry CTS	LC	Database clean-up
L1S	12	Milman Foundry JCT	Milman Foundry CTS	LC	Database clean-up
L27V	6	Nova SS	Nova SS	DFL	Database clean-up
M32W	8	Ingersoll JCT	Karn TS	LC	EB-2008-0272 Ex. D2/T2/S2, Ref. #D18: Woodstock Area Reinforcement
M33W	8	Ingersoll JCT	Karn TS	LC	EB-2008-0272 Ex. D2/T2/S2, Ref. #D18: Woodstock Area Reinforcement
T38B	8	TCE Halton Hills JCT	Halton TS	LC	EB-2008-0272 Ref. Ex. D1/T3/S3, section 3.4.2: Tap to TCE Halton Hills CGS
T38B	9	TCE Halton Hills JCT	TCE Halton Hills JCT	LC	EB-2008-0272 Ref. Ex. D1/T3/S3, section 3.4.2: Tap to TCE Halton Hills CGS
T39B	8	TCE Halton Hills JCT	Halton TS	LC	EB-2008-0272 Ref. Ex. D1/T3/S3, section 3.4.2: Tap to TCE Halton Hills CGS
T39B	9	TCE Halton Hills	TCE Halton	LC	EB-2008-0272 Ref. Ex. D1/T3/S3, section

Operation Designation	Section #	From	To	Functional Category	Explanation and or Project Reference #
		JCT	Hills JCT		3.4.2: Tap to TCE Halton Hills CGS
T61S	6	Timmins WestMine JCT	Weston Lake DS	LC	EB-2008-0272, Ex. D1/T3/S3, Table 4 “Other Historical Projects”: Tap to customer owned WestMine CTS
T61S	7	Timmins WestMine JCT	Timmins WestMine CTS	LC	EB-2008-0272, Ex. D1/T3/S3, Table 4 “Other Historical Projects”: Tap to customer owned WestMine CTS
V41H	8	Cardiff JCT	Cardiff TS	LC	Database clean-up
V41N	3	St.Clair E.C. JCT	Sarnia Scott TS	DFL	EB-2005-0501 Ex. D2/T2/S2, Ref # D19: Tap to St.Clair CGS (Sarnia Generation Connection Plan)
V41N	4	St.Clair E.C. JCT	St.Clair E.C. CGS	TDF	EB-2005-0501 Ex. D2/T2/S2, Ref # D19: Tap to St.Clair CGS (Sarnia Generation Connection Plan)
V41N	5	Nova SS	Nova SS	DFL	Database clean-up
V43N	6	St.Clair E.C. JCT	Sarnia Scott TS	DFL	EB-2005-0501 Ex. D2/T2/S2, Ref # D19: Tap to St.Clair CGS (Sarnia Generation Connection Plan)
V43N	7	St.Clair E.C. JCT	St.Clair E.C. CGS	TDF	EB-2005-0501 Ex. D2/T2/S2, Ref # D19: New tap to St.Clair CGS (Sarnia Generation Connection Plan)
X2H	10	Gardiner STR 44 JCT	Gardiner TS	LC	EB-2008-0272 Ref. #D23: Tap to T2 at Gardiner TS
X2H	11	Gardiner STR 44 JCT	Gardiner TS	LC	EB-2008-0272 Ref. #D23: Tap to T3 at Gardiner TS
X4H	5	Gardiner STR 44 JCT	Gardiner TS	LC	EB-2008-0272 Ref. #D23: Tap to T1 at Gardiner TS
X4H	6	Gardiner STR 44 JCT	Gardiner TS	LC	EB-2008-0272 Ref. #D23: Tap to T4 at Gardiner TS

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #57 List 1

Interrogatory

Issue 7.1: Is the cost allocation proposed by Hydro One appropriate?

References: i) Exhibit G2, Tab 1, Schedule 1
ii) EB-2008-0272, Exhibit G2, Tab 1, Schedule 1

a) Please provide a listing of those transmission stations in this Schedule whose Functional Category designation has changed since EB-2008-0272 and provide explanations as to the reason for each change.
b) Please provide a schedule that lists the new Transmission Stations noted in Exhibit G2, Tab 1, Schedule 2 (i.e., not included in EB-2008-0272). In each case please indicate the relevant project reference number (from either the EB-2008-0272 Application or this Application) that describes the investment.

Response

a) There are 4 transmission stations in this Schedule whose Functional Category has changed since EB-2008-0272. Table 1 list the stations used in both filings and their new and old functionalization assignments with the reason of the change.

Table 1: Transmission Station New Rate Pool Assignment

Station Number	Station Name	EB-2008-0272	EB-2010-0002	Explanation for the change
4035	Freeport SS	N	N,LC	Database cleanup
4091	Preston TS	TC	N,TC	Database cleanup
6231	K3D-10 SW JCT	N	N,LC	Database cleanup
6232	K6F-10 SW JCT	N	N,LC	Database cleanup

b) There is one new transmission station noted in EB-2010-0002, Exhibit G2, Tab 1, Schedule 2. Table 2 list the new station information and relevant investment project reference number.

Table 2: New Transmission Station List

Station Number	Station Name	Functional Category (EB-2010-0002)	Project Reference #
1302	Holland TS	TC	Project D24 in EB-2008-0272, Exhibit D2, Tab 2, Schedule 3

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #58 List 1

Interrogatory

Issue 7.1: Is the cost allocation proposed by Hydro One appropriate?

Reference: Exhibit G2, Tab 3, Schedule 1

a) Are there any Generator Line Connections listed in this schedule that were included in EB-2008-0272 but were not deemed to Generator Line Connections at that time? If so, what is the basis for the change in classification?
b) Please identify those Generator Line Connections that are new since EB-2008-0272.
c) What year's load and generator capacity values were used to determine the generator/load split?

Response

a) Yes, there are 17 Generator Line Connections listed in this schedule that were included in EB-2008-0272 but were not deemed to be Generator Line Connections at that time. Hydro One clarifies that these Generator Line Connections were inadvertently included in the current schedule. This oversight has been determined to have a negligible impact on the cost allocation results (<$200k on Network and Line Connection revenue requirements). The table below lists these 17 Line Segments.

Operation Designation	Section #	From	To
B22D	8	Majestic JCT	Majestic CTS
B23D	8	Majestic JCT	Majestic CTS
B4V	4	Amaranth JCT	Amaranth CTS
C23Z	4	KEPA Wind Farm JCT	Port Alma WF CSS
H12P	1	Hearn SS	Portlands Energy JCT
H13P	1	Hearn SS	Portlands Energy JCT
H14P	1	Hearn SS	Portlands Energy JCT
L24L	3	Longwood TS	Longwood TS
L26L	3	Longwood TS	Longwood TS
Q21P	1	Beck #2 TS	Beck Pump Storage GS
Q22P	1	Beck #2 TS	Beck Pump Storage GS
T38B	7	Trafalgar DESN JCT	Trafalgar TS
T39B	7	Trafalgar DESN JCT	Trafalgar TS
V74R	9	Richview TS	Richview TS
W71D	4	Lower Notch JCT	Lower Notch GS
W71D	5	Lower Notch JCT	Lower Notch GS
WT1T	5	ESWF JCT	ESWF CSS

b) There is one new Generator Line Connection since EB-2008-0272. The table below presents this new Generator Line Connection information.

Operation Designation	**Section #**	**From**	**To**	**% Generator**	**% Load**
A4K	11	Cyrville Rd JCT	Cyrville JCT	15%	85%

c) The 2011 forecast annual non-coincident peak demand and 2008 generator capacity were used to determine the allocation percentages for Generator Line Connection Assets.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #59 List 1

Interrogatory

Issue 7.1: Is the cost allocation proposed by Hydro One appropriate?

Reference: Exhibit G2, Tab 3, Schedule 2

a) Are there any Generator Station Connections listed in this Schedule that were included in EB-2008-0272 but not considered to be Generator Station Connections at that time? If so, what is the basis for the change in classification?
b) Please identify those Generator Station Connections that are new since EB-2008-0272.
c) What year's load and generator capacity was used to determine the generator/load split?

Response

a) No, all of Generator Station Connections listed in this Schedule were also considered to be Generator Station Connections in EB-2008-0272.

b) There are no new Generator Station Connections since EB-2008-0272.

c) The 2011 forecast annual non-coincident peak demand and 2008 generator capacity were used to determine the allocation percentages for Generator Station Connection Assets.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #60 List 1

Interrogatory

Issue 7.1: Is the cost allocation proposed by Hydro One appropriate?

References: i) Exhibit G2, Tab 4, Schedule 1
ii) EB-2008-0272, Exhibit G2, Tab 4, Schedule 1

a) Please explain why the Gross Book value for the Other Category has increased from roughly $40 M in EB-2008-0272 to over $300 M.
b) Please explain why the Gross Book value of Generator Station Connections has decreased as between 2010 (per EB-2008-0272) and 2011.
c) Please explain why the Gross Book value of Line Connection – Dual Function Lines has decreased as between 2010 (per EB-2008-0272) and 2011.
d) Please explain why the Gross Book value of Transformation Connection decreased as between 2010 (per EB-2008-0272) and 2011.

Response

a) The difference is attributable primarily to two factors. The first is that the 2010 GBV per EB-2008-0272 was calculated based on actual year end 2007 fixed asset values and the forecast of in-service additions available at the time, while the 2011 value per the current application is based on actual 2008 year end fixed asset values and the current forecast data available. As discussed in Exhibit I, Tab 5 Schedule 8, in-service additions to the Rate Base are lower than was forecast in EB-2008-0272.

The second factor contributing to the difference in values is the inclusion of some assets in the "Other" functional category that should belong in other categories. Hydro One has refined the assignment of assets to the "Other" category and determined that about $150 M should be allocated to other functional categories, the bulk of which will go to the Network category. As noted on page 20 of Exhibit G1, Tab 2, Schedule 1, the financial values associated with the "Other" functional category are proportionally allocated to the Network, Line Connection and Transformation Connection pools and as such this re-allocation of "Other" assets does not significantly impact the total costs assigned to these pools. The impact of this change on the 2011 rate pool revenue requirements is estimated to be: Network +$3M (~0.3%), Line Connection +$0.5M (~0.2%), Transformation Connection -$3.5M (~1%). This change will be reflected in the final determination of the rate pool revenue requirements subsequent to the Decision of the Board in this Application.

b) The difference is primarily attributable to the fact that 2010 GBV per EB-2008-0272 was calculated based on actual year end 2007 fixed asset values and the forecast of in-service additions available at the time, while the 2011 value per the current application is based on actual 2008 year end fixed asset values and the current forecast data available.

c) Please see the response to Part b) above. Also contributing to the difference is a decrease in the 2011 GBV of "Line Connection-Dual Function Lines" due to a declining share of the asset costs allocated to the Line Connection portion of DFL as a result of lower DFL load customer demand.

d) Please see the response to Part b) above.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #61 List 1

Interrogatory

Issue 7.1: Is the cost allocation proposed by Hydro One appropriate?

References: i) Exhibit G2, Tab 4, Schedules 1 & 2
ii) EB-2008-0272, Exhibit G2, Tab 4, Schedules 1 & 2

a) Please provide a schedule that sets out the 2010 (per EB-2008-0272) and 2011 Gross Book value and Depreciation for each Function Category and calculate year over year percentage change for each.

b) In virtually all cases the percentage change in Gross Book Value differs materially from the percentage change in Depreciation; please provide an explanation as to why.

Response

a) Please refer to the schedule below.

	Gross Book Value[$M]			**Depreciation [$M]**		
Functional Category	2010 (EB-2008-0272)	2011 (EB-2010-0002)	2011 Over 2010 Change	2010 (EB-2008-0272)	2011 (EB-2010-0002)	2011 Over 2010 Change
Network	5,319.6	5,476.1	3%	104.8	118.1	13%
Line Connection	1,398.4	1,416.5	1%	24.7	27.4	11%
Transformation Connection	2,440.4	2,434.7	0%	56.3	60.0	7%
Wholesale Meter	4.6	3.5	-24%	0.1	0.1	0%
Network - Dual Function Line	621.4	634.4	2%	8.9	9.8	10%
Line Connection - Dual Function Line	187.9	179.7	-4%	2.7	2.8	4%
Generator Line Connection	146.1	147.9	1%	2.6	2.8	8%
Generator Station Connection	37.4	34.9	-7%	0.8	0.8	0%
Common	1,584.1	1,660.8	5%	78.5	69.4	-12%
Other	40.4	308.8	664%	0.4	4.6	1050%
Total	11,780.2	12,297.3	4%	279.8	295.6	6%

b) The noted differences are primarily attributable to the fact that the 2010 and 2011 Gross Book Value and Depreciation numbers compared are calculated based on a different forecast of in-service additions and customer load, as discussed in Exhibit I, Tab 4, Schedule 60.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #62 List 1

Interrogatory

Issue 8.1: **Is it appropriate to implement "AMPCO's High 5 Proposal" in place of the status quo charge determinants for Network service?**

Reference: Exhibit H1, Tab 2, Schedule 1

a) With respect to Table #1, please provide a schedule that sets out the total number of Delivery Points, for each customer category, for 2011 and the number where 85% of NCP from 7 am to 7 pm is greater than the Monthly CP.

Response

Transmission delivery points are billed for Network service on a monthly basis. In each month, the billing demand can be either 85% NCP (7am to 7pm) or CP, whichever is the highest.

The attached table summarizes the number of billed months for which the delivery points per customer group are charged based on 85% NCP (7am to 7pm) demand.

Category	# of Customer Delivery Points	Total Billed Months (Del Pts *12)	85% NCP Billed Months
Directs	90	1080	633
LDCs	430	5160	821
Power Producers	89	1068	513

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #63 List 1

Interrogatory

Issue 8.1: Is it appropriate to implement "AMPCO's High 5 Proposal" in place of the status quo charge determinants for Network service?

References: i) Exhibit H1, Tab 3, Schedule 1, page 5
ii) Exhibit H1, Tab 2, Schedule 1, Table #1

a) Please provide a Schedule that for each Transmission delivery point in 2011 lists the total of the 12 monthly Network billing determinants. In the same schedule please set out percentage each billing point contributed to the total for all Network billing determinants in 2011. (Note: It is not necessary to identify the specific customer associated with each delivery point.)

b) Please include in the schedule prepared for part (a), the each delivery point's 2011 contribution (in percentage terms) to the All Customers' Average Coincident Peak Demand as defined by AMPCO's "High Five Proposal" and discussed in reference (i).

c) What is the anticipated costs that will be incurred by the IESO to implement the necessary tool and business process changes that would be required by AMPCO's "High 5 Proposal"?

Response

a) and b)

The information requested is provided in the table below. Please note that the information in the table below has not changed. Hydro One has only combined the tables that were filed on August 16, 2010.

	Current Methodology		High 5 Proposal	
Delivery Point ID	**Total of 12 monthly Network Charge Determinants (KW)**	**Share of Total Network Charge Determinants**	**Average of Coincident Peak Demand on the 5 highest peak days in 2011 (KW)**	**Share of Total High-5 Charge Determinants**
1	146,066	0.0604%	457	0.0021%
2	851	0.0004%	0	0.0000%
3	403	0.0002%	15	0.0001%
4	3,660	0.0015%	191	0.0009%
5	40,234	0.0166%	0	0.0000%
6	356	0.0001%	0	0.0000%
7	306,937	0.1269%	0	0.0000%

	Current Methodology		High 5 Proposal	
Delivery Point ID	**Total of 12 monthly Network Charge Determinants (KW)**	**Share of Total Network Charge Determinants**	**Average of Coincident Peak Demand on the 5 highest peak days in 2011 (KW)**	**Share of Total High-5 Charge Determinants**
8	4,891	0.0020%	312	0.0014%
9	2,176	0.0009%	0	0.0000%
10	30,753	0.0127%	2,074	0.0096%
11	66,320	0.0274%	7,157	0.0332%
12	845,056	0.3495%	82,967	0.3854%
13	19,927	0.0082%	921	0.0043%
14	2,946	0.0012%	0	0.0000%
15	926,035	0.3830%	81,375	0.3780%
16	0	0.0000%	0	0.0000%
17	276,955	0.1145%	26,473	0.1230%
18	939,558	0.3886%	72,829	0.3383%
19	435,237	0.1800%	30,158	0.1401%
20	85,040	0.0352%	5,910	0.0275%
21	21,399	0.0089%	1,548	0.0072%
22	2,013,695	0.8328%	189,851	0.8819%
23	719,409	0.2975%	73,156	0.3398%
24	6,013	0.0025%	0	0.0000%
25	410,667	0.1698%	29,782	0.1383%
26	5,857	0.0024%	492	0.0023%
27	39,417	0.0163%	1,109	0.0052%
28	248,749	0.1029%	20,818	0.0967%
29	90,103	0.0373%	561	0.0026%
30	9,929	0.0041%	0	0.0000%
31	161	0.0001%	11	0.0001%
32	75,640	0.0313%	5,809	0.0270%
33	24,578	0.0102%	2,268	0.0105%
34	5,020	0.0021%	0	0.0000%
35	48,846	0.0202%	3,029	0.0141%
36	650,321	0.2690%	56,367	0.2618%
37	408,386	0.1689%	26,527	0.1232%
38	514,644	0.2128%	49,051	0.2279%
39	1,993,821	0.8246%	204,922	0.9519%
40	98,150	0.0406%	6,070	0.0282%
41	434,412	0.1797%	37,583	0.1746%
42	651,311	0.2694%	66,541	0.3091%
43	262,599	0.1086%	23,530	0.1093%
44	114,815	0.0475%	12,196	0.0567%
45	12,467	0.0052%	749	0.0035%
46	719,286	0.2975%	42,173	0.1959%
47	5,234	0.0022%	0	0.0000%
48	0	0.0000%	0	0.0000%

	Current Methodology		High 5 Proposal	
Delivery Point ID	**Total of 12 monthly Network Charge Determinants (KW)**	**Share of Total Network Charge Determinants**	**Average of Coincident Peak Demand on the 5 highest peak days in 2011 (KW)**	**Share of Total High-5 Charge Determinants**
49	396,672	0.1641%	0	0.0000%
50	574,516	0.2376%	43,840	0.2037%
51	1,079,701	0.4465%	94,758	0.4402%
52	1,618,097	0.6692%	151,866	0.7055%
53	254,299	0.1052%	19,668	0.0914%
54	490,250	0.2028%	48,761	0.2265%
55	721,568	0.2984%	57,677	0.2679%
56	832,443	0.3443%	85,871	0.3989%
57	117,774	0.0487%	9,327	0.0433%
58	1,218,849	0.5041%	61,971	0.2879%
59	133,068	0.0550%	12,906	0.0600%
60	1,975,938	0.8172%	184,545	0.8573%
61	456,733	0.1889%	38,778	0.1801%
62	62,777	0.0260%	0	0.0000%
63	115,717	0.0479%	11,685	0.0543%
64	260,045	0.1075%	23,192	0.1077%
65	1,231,857	0.5095%	117,964	0.5480%
66	1,484,964	0.6141%	141,595	0.6577%
67	309,015	0.1278%	28,507	0.1324%
68	1,008,854	0.4172%	100,422	0.4665%
69	787,130	0.3255%	83,188	0.3864%
70	784,447	0.3244%	62,373	0.2897%
71	76,583	0.0317%	5,370	0.0249%
72	46,731	0.0193%	0	0.0000%
73	0	0.0000%	0	0.0000%
74	109,986	0.0455%	9,932	0.0461%
75	1,111,373	0.4596%	102,123	0.4744%
76	451,735	0.1868%	47,687	0.2215%
77	30,632	0.0127%	1,824	0.0085%
78	1,376,025	0.5691%	138,920	0.6453%
79	1,320,401	0.5461%	145,890	0.6777%
80	159,041	0.0658%	15,254	0.0709%
81	300,664	0.1243%	27,056	0.1257%
82	0	0.0000%	0	0.0000%
83	1,404,164	0.5807%	123,335	0.5729%
84	10,107	0.0042%	0	0.0000%
85	88	0.0000%	0	0.0000%
86	540,205	0.2234%	45,841	0.2129%
87	777,757	0.3217%	69,088	0.3209%
88	816,444	0.3377%	84,127	0.3908%
89	111	0.0000%	0	0.0000%

	Current Methodology		High 5 Proposal	
Delivery Point ID	**Total of 12 monthly Network Charge Determinants (KW)**	**Share of Total Network Charge Determinants**	**Average of Coincident Peak Demand on the 5 highest peak days in 2011 (KW)**	**Share of Total High-5 Charge Determinants**
90	3,804	0.0016%	218	0.0010%
91	1,234,830	0.5107%	111,227	0.5167%
92	1,400,398	0.5792%	144,129	0.6695%
93	1,008,533	0.4171%	89,507	0.4158%
94	344,858	0.1426%	30,553	0.1419%
95	157,350	0.0651%	14,143	0.0657%
96	86,352	0.0357%	6,991	0.0325%
97	81,394	0.0337%	0	0.0000%
98	28,349	0.0117%	1,411	0.0066%
99	1,340,186	0.5543%	119,546	0.5553%
100	289	0.0001%	0	0.0000%
101	0	0.0000%	0	0.0000%
102	620,299	0.2565%	56,644	0.2631%
103	980,149	0.4054%	92,379	0.4291%
104	364,571	0.1508%	27,066	0.1257%
105	338,249	0.1399%	18,137	0.0843%
106	432,202	0.1787%	27,620	0.1283%
107	388,666	0.1607%	27,442	0.1275%
108	25,551	0.0106%	1,747	0.0081%
109	111,451	0.0461%	9,280	0.0431%
110	849,086	0.3512%	80,037	0.3718%
111	35,733	0.0148%	2,146	0.0100%
112	65,541	0.0271%	4,700	0.0218%
113	210,693	0.0871%	14,538	0.0675%
114	90,114	0.0373%	7,203	0.0335%
115	33,779	0.0140%	1,866	0.0087%
116	15,009	0.0062%	0	0.0000%
117	209,816	0.0868%	16,886	0.0784%
118	1,049,636	0.4341%	99,716	0.4632%
119	266,596	0.1103%	19,071	0.0886%
120	80,965	0.0335%	6,326	0.0294%
121	675,295	0.2793%	63,120	0.2932%
122	234,688	0.0971%	14,993	0.0696%
123	21,268	0.0088%	1,126	0.0052%
124	62,044	0.0257%	5,895	0.0274%
125	856,113	0.3541%	80,635	0.3746%
126	178	0.0001%	0	0.0000%
127	115,268	0.0477%	5,615	0.0261%
128	74,713	0.0309%	5,570	0.0259%
129	1,284,857	0.5314%	140,426	0.6523%
130	13,543	0.0056%	1,112	0.0052%

	Current Methodology		High 5 Proposal	
Delivery Point ID	**Total of 12 monthly Network Charge Determinants (KW)**	**Share of Total Network Charge Determinants**	**Average of Coincident Peak Demand on the 5 highest peak days in 2011 (KW)**	**Share of Total High-5 Charge Determinants**
131	0	0.0000%	0	0.0000%
132	1,598	0.0007%	0	0.0000%
133	108,149	0.0447%	6,622	0.0308%
134	32,574	0.0135%	1,656	0.0077%
135	9,063	0.0037%	0	0.0000%
136	283,093	0.1171%	23,646	0.1098%
137	158,178	0.0654%	12,460	0.0579%
138	1,009,296	0.4174%	73,312	0.3406%
139	1,688,235	0.6982%	146,582	0.6809%
140	482,013	0.1993%	36,075	0.1676%
141	147,997	0.0612%	11,602	0.0539%
142	429,753	0.1777%	32,657	0.1517%
143	540,255	0.2234%	37,158	0.1726%
144	173,048	0.0716%	11,819	0.0549%
145	1,158,645	0.4792%	98,593	0.4580%
146	155,489	0.0643%	13,772	0.0640%
147	648,253	0.2681%	61,017	0.2834%
148	117,354	0.0485%	10,923	0.0507%
149	112,713	0.0466%	10,172	0.0472%
150	951,209	0.3934%	89,340	0.4150%
151	294,105	0.1216%	23,765	0.1104%
152	54,098	0.0224%	2,996	0.0139%
153	117,700	0.0487%	6,881	0.0320%
154	1	0.0000%	0	0.0000%
155	18,048	0.0075%	968	0.0045%
156	503,549	0.2083%	43,340	0.2013%
157	582,603	0.2409%	55,914	0.2597%
158	410,107	0.1696%	39,694	0.1844%
159	1,380,993	0.5711%	129,764	0.6028%
160	178,728	0.0739%	10,573	0.0491%
161	318,577	0.1318%	26,015	0.1208%
162	8,773	0.0036%	332	0.0015%
163	12,838	0.0053%	481	0.0022%
164	4,533,461	1.8749%	496,825	2.3079%
165	118,166	0.0489%	7,912	0.0368%
166	1,389,423	0.5746%	138,640	0.6440%
167	420,636	0.1740%	41,208	0.1914%
168	31,171	0.0129%	1,458	0.0068%
169	1,540,149	0.6370%	156,229	0.7257%
170	366,231	0.1515%	40,523	0.1882%
171	1,855,440	0.7674%	178,967	0.8314%

	Current Methodology		High 5 Proposal	
Delivery Point ID	**Total of 12 monthly Network Charge Determinants (KW)**	**Share of Total Network Charge Determinants**	**Average of Coincident Peak Demand on the 5 highest peak days in 2011 (KW)**	**Share of Total High-5 Charge Determinants**
172	50,804	0.0210%	3,731	0.0173%
173	526,192	0.2176%	41,856	0.1944%
174	242,748	0.1004%	26,053	0.1210%
175	18,442	0.0076%	1,137	0.0053%
176	990,270	0.4095%	73,760	0.3426%
177	162,855	0.0674%	15,606	0.0725%
178	2,106,034	0.8710%	209,699	0.9741%
179	145,914	0.0603%	8,895	0.0413%
180	257,016	0.1063%	12,495	0.0580%
181	158,437	0.0655%	5,530	0.0257%
182	139,853	0.0578%	6,281	0.0292%
183	203,241	0.0841%	20,208	0.0939%
184	88,050	0.0364%	6,989	0.0325%
185	131,309	0.0543%	9,337	0.0434%
186	137,617	0.0569%	8,473	0.0394%
187	771,448	0.3191%	59,627	0.2770%
188	440,169	0.1820%	34,114	0.1585%
189	606,911	0.2510%	47,174	0.2191%
190	111,744	0.0462%	7,020	0.0326%
191	784,283	0.3244%	64,669	0.3004%
192	1,227,232	0.5076%	106,474	0.4946%
193	1,642,673	0.6794%	139,535	0.6482%
194	5,116	0.0021%	488	0.0023%
195	208,768	0.0863%	10,921	0.0507%
196	79,051	0.0327%	1,399	0.0065%
197	326,216	0.1349%	28,549	0.1326%
198	611,388	0.2529%	56,417	0.2621%
199	536,903	0.2220%	44,957	0.2088%
200	137,348	0.0568%	11,479	0.0533%
201	247,341	0.1023%	20,696	0.0961%
202	1,981,177	0.8194%	197,377	0.9169%
203	166,427	0.0688%	15,521	0.0721%
204	177,944	0.0736%	13,249	0.0615%
205	26,221	0.0108%	1,908	0.0089%
206	141,551	0.0585%	15,863	0.0737%
207	997,185	0.4124%	97,098	0.4510%
208	345,017	0.1427%	33,394	0.1551%
209	950,117	0.3929%	63,139	0.2933%
210	16,232	0.0067%	0	0.0000%
211	164,500	0.0680%	10,106	0.0469%
212	557,911	0.2307%	40,319	0.1873%

	Current Methodology		High 5 Proposal	
Delivery Point ID	**Total of 12 monthly Network Charge Determinants (KW)**	**Share of Total Network Charge Determinants**	**Average of Coincident Peak Demand on the 5 highest peak days in 2011 (KW)**	**Share of Total High-5 Charge Determinants**
213	181,760	0.0752%	13,104	0.0609%
214	567,003	0.2345%	44,367	0.2061%
215	399,116	0.1651%	36,804	0.1710%
216	44,848	0.0185%	2,800	0.0130%
217	141,328	0.0584%	8,907	0.0414%
218	24,651	0.0102%	1,494	0.0069%
219	67,522	0.0279%	5,642	0.0262%
220	713,526	0.2951%	66,489	0.3089%
221	424,559	0.1756%	37,619	0.1748%
222	58,339	0.0241%	3,918	0.0182%
223	1,229,780	0.5086%	102,125	0.4744%
224	434,738	0.1798%	48,713	0.2263%
225	66,389	0.0275%	5,600	0.0260%
226	59,998	0.0248%	2,756	0.0128%
227	74,768	0.0309%	7,130	0.0331%
228	377,849	0.1563%	32,892	0.1528%
229	350,602	0.1450%	37,101	0.1723%
230	35,908	0.0149%	2,987	0.0139%
231	1,703,578	0.7046%	121,969	0.5666%
232	781,817	0.3233%	66,185	0.3074%
233	1,189	0.0005%	79	0.0004%
234	10,716	0.0044%	128	0.0006%
235	16,073	0.0066%	318	0.0015%
236	39,137	0.0162%	1,572	0.0073%
237	64,530	0.0267%	4,368	0.0203%
238	468,478	0.1938%	27,999	0.1301%
239	224,491	0.0928%	22,946	0.1066%
240	377,915	0.1563%	31,110	0.1445%
241	4,658	0.0019%	278	0.0013%
242	2,400,429	0.9928%	233,694	1.0856%
243	144,885	0.0599%	9,654	0.0448%
244	74,587	0.0308%	5,233	0.0243%
245	281,359	0.1164%	20,779	0.0965%
246	262,603	0.1086%	31,588	0.1467%
247	542,690	0.2244%	45,969	0.2135%
248	90,148	0.0373%	4,717	0.0219%
249	220,158	0.0911%	16,726	0.0777%
250	797,498	0.3298%	90,194	0.4190%
251	625,182	0.2586%	60,806	0.2825%
252	1,141,279	0.4720%	98,765	0.4588%
253	288,282	0.1192%	24,116	0.1120%

	Current Methodology		High 5 Proposal	
Delivery Point ID	**Total of 12 monthly Network Charge Determinants (KW)**	**Share of Total Network Charge Determinants**	**Average of Coincident Peak Demand on the 5 highest peak days in 2011 (KW)**	**Share of Total High-5 Charge Determinants**
254	337,716	0.1397%	29,815	0.1385%
255	776,661	0.3212%	65,408	0.3038%
256	1,156,007	0.4781%	117,660	0.5466%
257	70,316	0.0291%	5,078	0.0236%
258	15,172	0.0063%	0	0.0000%
259	122,780	0.0508%	7,532	0.0350%
260	825,205	0.3413%	68,623	0.3188%
261	535,735	0.2216%	50,644	0.2353%
262	766,346	0.3169%	73,848	0.3430%
263	681,634	0.2819%	59,043	0.2743%
264	359,429	0.1487%	33,431	0.1553%
265	1,156,086	0.4781%	114,945	0.5340%
266	14,145	0.0059%	0	0.0000%
267	58,539	0.0242%	4,883	0.0227%
268	127,036	0.0525%	7,970	0.0370%
269	266,887	0.1104%	24,970	0.1160%
270	182,280	0.0754%	15,234	0.0708%
271	82,954	0.0343%	4,562	0.0212%
272	477,218	0.1974%	52,230	0.2426%
273	489,183	0.2023%	52,915	0.2458%
274	0	0.0000%	0	0.0000%
275	694,067	0.2870%	64,140	0.2979%
276	108,471	0.0449%	7,299	0.0339%
277	705,664	0.2918%	38,980	0.1811%
278	544,689	0.2253%	49,939	0.2320%
279	821,292	0.3397%	90,992	0.4227%
280	1,074,034	0.4442%	102,173	0.4746%
281	119,291	0.0493%	2,893	0.0134%
282	201,646	0.0834%	22,190	0.1031%
283	1,914,116	0.7916%	170,172	0.7905%
284	300,178	0.1241%	16,207	0.0753%
285	452,007	0.1869%	33,756	0.1568%
286	795,409	0.3290%	51,977	0.2414%
287	600,670	0.2484%	50,810	0.2360%
288	18,189	0.0075%	0	0.0000%
289	45,109	0.0187%	3,555	0.0165%
290	96,030	0.0397%	6,275	0.0292%
291	152,000	0.0629%	11,289	0.0524%
292	98	0.0000%	0	0.0000%
293	539,806	0.2232%	37,806	0.1756%
294	269,923	0.1116%	23,985	0.1114%

	Current Methodology		High 5 Proposal	
Delivery Point ID	**Total of 12 monthly Network Charge Determinants (KW)**	**Share of Total Network Charge Determinants**	**Average of Coincident Peak Demand on the 5 highest peak days in 2011 (KW)**	**Share of Total High-5 Charge Determinants**
295	1,110,769	0.4594%	92,322	0.4289%
296	11,435	0.0047%	0	0.0000%
297	54,693	0.0226%	3,506	0.0163%
298	596,531	0.2467%	48,687	0.2262%
299	489,268	0.2023%	47,019	0.2184%
300	639,364	0.2644%	59,999	0.2787%
301	95,908	0.0397%	9,031	0.0420%
302	854,040	0.3532%	81,630	0.3792%
303	2,088,086	0.8636%	211,095	0.9806%
304	0	0.0000%	0	0.0000%
305	269,028	0.1113%	15,243	0.0708%
306	11,208	0.0046%	644	0.0030%
307	82,616	0.0342%	3,804	0.0177%
308	105,886	0.0438%	8,679	0.0403%
309	75,753	0.0313%	5,597	0.0260%
310	66,243	0.0274%	3,254	0.0151%
311	245,591	0.1016%	19,715	0.0916%
312	71,915	0.0297%	3,885	0.0180%
313	135,867	0.0562%	10,056	0.0467%
314	847,419	0.3505%	85,967	0.3993%
315	856,767	0.3543%	91,107	0.4232%
316	1,603,130	0.6630%	158,948	0.7384%
317	458,046	0.1894%	37,408	0.1738%
318	375,090	0.1551%	25,806	0.1199%
319	49,569	0.0205%	2,857	0.0133%
320	6,172	0.0026%	230	0.0011%
321	27,894	0.0115%	2,045	0.0095%
322	126,921	0.0525%	11,487	0.0534%
323	1,651,152	0.6829%	171,994	0.7990%
324	406,595	0.1682%	34,331	0.1595%
325	59,942	0.0248%	4,836	0.0225%
326	438,343	0.1813%	34,149	0.1586%
327	505,717	0.2092%	55,848	0.2594%
328	6,818	0.0028%	538	0.0025%
329	447,158	0.1849%	26,161	0.1215%
330	983,738	0.4068%	102,938	0.4782%
331	683,975	0.2829%	74,742	0.3472%
332	24,031	0.0099%	1,325	0.0062%
333	39,656	0.0164%	2,994	0.0139%
334	3,915	0.0016%	57	0.0003%
335	114,878	0.0475%	4,865	0.0226%

	Current Methodology		High 5 Proposal	
Delivery Point ID	**Total of 12 monthly Network Charge Determinants (KW)**	**Share of Total Network Charge Determinants**	**Average of Coincident Peak Demand on the 5 highest peak days in 2011 (KW)**	**Share of Total High-5 Charge Determinants**
336	520,862	0.2154%	38,483	0.1788%
337	398,965	0.1650%	33,138	0.1539%
338	4,238	0.0018%	246	0.0011%
339	1,761	0.0007%	0	0.0000%
340	35,372	0.0146%	0	0.0000%
341	129,822	0.0537%	7,987	0.0371%
342	720,686	0.2981%	72,943	0.3388%
343	1,330,940	0.5504%	89,384	0.4152%
344	139,130	0.0575%	11,020	0.0512%
345	28,642	0.0118%	1,897	0.0088%
346	122,204	0.0505%	8,209	0.0381%
347	26,637	0.0110%	63	0.0003%
348	40,135	0.0166%	646	0.0030%
349	119	0.0000%	0	0.0000%
350	0	0.0000%	0	0.0000%
351	676,269	0.2797%	51,756	0.2404%
352	48,692	0.0201%	3,695	0.0172%
353	726,506	0.3005%	69,687	0.3237%
354	3,842	0.0016%	246	0.0011%
355	561,797	0.2323%	56,096	0.2606%
356	55,588	0.0230%	5,410	0.0251%
357	1,311,451	0.5424%	117,976	0.5480%
358	25,463	0.0105%	1,470	0.0068%
359	18,327	0.0076%	1,136	0.0053%
360	394,560	0.1632%	39,845	0.1851%
361	220,252	0.0911%	23,651	0.1099%
362	23,258	0.0096%	1,709	0.0079%
363	4,471	0.0018%	313	0.0015%
364	339,301	0.1403%	28,334	0.1316%
365	413	0.0002%	0	0.0000%
366	1,516	0.0006%	0	0.0000%
367	1,472	0.0006%	41	0.0002%
368	160,351	0.0663%	12,696	0.0590%
369	54,795	0.0227%	33	0.0002%
370	64,903	0.0268%	4,409	0.0205%
371	208,163	0.0861%	18,468	0.0858%
372	218,436	0.0903%	17,222	0.0800%
373	81,174	0.0336%	6,957	0.0323%
374	524,155	0.2168%	42,035	0.1953%
375	905,757	0.3746%	100,514	0.4669%
376	46,576	0.0193%	3,348	0.0156%

	Current Methodology		High 5 Proposal	
Delivery Point ID	**Total of 12 monthly Network Charge Determinants (KW)**	**Share of Total Network Charge Determinants**	**Average of Coincident Peak Demand on the 5 highest peak days in 2011 (KW)**	**Share of Total High-5 Charge Determinants**
377	31,228	0.0129%	77	0.0004%
378	868	0.0004%	0	0.0000%
379	33	0.0000%	2	0.0000%
380	347,837	0.1439%	28,062	0.1304%
381	1,335,713	0.5524%	103,902	0.4827%
382	1,169,498	0.4837%	95,522	0.4437%
383	470,099	0.1944%	31,783	0.1476%
384	645,181	0.2668%	56,561	0.2627%
385	17,180	0.0071%	72	0.0003%
386	6,241	0.0026%	0	0.0000%
387	45,993	0.0190%	2,913	0.0135%
388	770,777	0.3188%	64,351	0.2989%
389	1,180,123	0.4881%	88,993	0.4134%
390	77,533	0.0321%	6,507	0.0302%
391	678,514	0.2806%	62,983	0.2926%
392	207,842	0.0860%	22,060	0.1025%
393	554,883	0.2295%	41,183	0.1913%
394	59,986	0.0248%	4,198	0.0195%
395	513,310	0.2123%	32,732	0.1521%
396	428,105	0.1771%	34,399	0.1598%
397	5,540	0.0023%	488	0.0023%
398	110,131	0.0455%	10,085	0.0468%
399	55,938	0.0231%	4,882	0.0227%
400	47,354	0.0196%	0	0.0000%
401	0	0.0000%	0	0.0000%
402	664,895	0.2750%	47,397	0.2202%
403	0	0.0000%	0	0.0000%
404	2,102,616	0.8696%	227,390	1.0563%
405	637,141	0.2635%	59,086	0.2745%
406	64,298	0.0266%	3,889	0.0181%
407	236,233	0.0977%	15,757	0.0732%
408	367,023	0.1518%	35,898	0.1668%
409	1,302,201	0.5386%	104,077	0.4835%
410	914,645	0.3783%	87,004	0.4042%
411	47,621	0.0197%	9,247	0.0430%
412	286,542	0.1185%	25,828	0.1200%
413	34,754	0.0144%	2,075	0.0096%
414	25,106	0.0104%	441	0.0021%
415	364,062	0.1506%	26,526	0.1232%
416	35,117	0.0145%	2,019	0.0094%
417	3,073	0.0013%	0	0.0000%

	Current Methodology		High 5 Proposal	
Delivery Point ID	**Total of 12 monthly Network Charge Determinants (KW)**	**Share of Total Network Charge Determinants**	**Average of Coincident Peak Demand on the 5 highest peak days in 2011 (KW)**	**Share of Total High-5 Charge Determinants**
418	49	0.0000%	4	0.0000%
419	1,192,524	0.4932%	119,559	0.5554%
420	50,286	0.0208%	3,728	0.0173%
421	2,631,959	1.0885%	272,242	1.2646%
422	385,970	0.1596%	33,786	0.1569%
423	2,171,786	0.8982%	214,996	0.9987%
424	765,950	0.3168%	66,936	0.3109%
425	73,312	0.0303%	5,326	0.0247%
426	121,957	0.0504%	7,557	0.0351%
427	952,652	0.3940%	84,354	0.3918%
428	363,330	0.1503%	25,424	0.1181%
429	12,481	0.0052%	792	0.0037%
430	593,979	0.2457%	53,417	0.2481%
431	169,649	0.0702%	10,590	0.0492%
432	13,496	0.0056%	549	0.0026%
433	0	0.0000%	0	0.0000%
434	2,075,019	0.8582%	201,939	0.9381%
435	1,451,603	0.6003%	140,003	0.6504%
436	36,641	0.0152%	1,520	0.0071%
437	331,230	0.1370%	27,770	0.1290%
438	69	0.0000%	0	0.0000%
439	23,913	0.0099%	1,716	0.0080%
440	39,908	0.0165%	2,674	0.0124%
441	282,161	0.1167%	24,110	0.1120%
442	257,241	0.1064%	22,747	0.1057%
443	1,202,609	0.4974%	101,220	0.4702%
444	29,618	0.0122%	1,396	0.0065%
445	359,130	0.1485%	31,528	0.1465%
446	2,211	0.0009%	0	0.0000%
447	30,240	0.0125%	1,824	0.0085%
448	3,430	0.0014%	111	0.0005%
449	314,034	0.1299%	21,277	0.0988%
450	1,115,797	0.4615%	105,854	0.4917%
451	994,817	0.4114%	73,124	0.3397%
452	249	0.0001%	0	0.0000%
453	24,361	0.0101%	1,734	0.0081%
454	40,572	0.0168%	3,376	0.0157%
455	513,286	0.2123%	42,896	0.1993%
456	334,039	0.1381%	24,550	0.1140%
457	19,255	0.0080%	1,204	0.0056%
458	30,543	0.0126%	1,472	0.0068%

	Current Methodology		High 5 Proposal	
Delivery Point ID	**Total of 12 monthly Network Charge Determinants (KW)**	**Share of Total Network Charge Determinants**	**Average of Coincident Peak Demand on the 5 highest peak days in 2011 (KW)**	**Share of Total High-5 Charge Determinants**
459	490,483	0.2029%	18,330	0.0851%
460	687,974	0.2845%	57,181	0.2656%
461	78,761	0.0326%	5,132	0.0238%
462	490,103	0.2027%	32,302	0.1501%
463	395,294	0.1635%	27,088	0.1258%
464	176,817	0.0731%	15,766	0.0732%
465	74,925	0.0310%	5,934	0.0276%
466	139,484	0.0577%	13,377	0.0621%
467	32,110	0.0133%	2,688	0.0125%
468	193	0.0001%	14	0.0001%
469	480,985	0.1989%	50,175	0.2331%
470	1,067,659	0.4416%	81,778	0.3799%
471	653,284	0.2702%	49,789	0.2313%
472	12,098	0.0050%	0	0.0000%
473	265,604	0.1098%	20,042	0.0931%
474	480,356	0.1987%	47,069	0.2186%
475	1,040,204	0.4302%	91,193	0.4236%
476	734,104	0.3036%	64,113	0.2978%
477	277,415	0.1147%	22,200	0.1031%
478	141,025	0.0583%	13,129	0.0610%
479	244,636	0.1012%	23,821	0.1107%
480	79,517	0.0329%	6,025	0.0280%
481	16,696	0.0069%	1,010	0.0047%
482	474,841	0.1964%	40,953	0.1902%
483	1,731,413	0.7161%	176,412	0.8195%
484	2,649	0.0011%	0	0.0000%
485	16,596	0.0069%	50	0.0002%
486	495	0.0002%	0	0.0000%
487	426	0.0002%	0	0.0000%
488	78	0.0000%	0	0.0000%
489	19,912	0.0082%	24	0.0001%
490	238,087	0.0985%	21,290	0.0989%
491	14,191	0.0059%	874	0.0041%
492	896	0.0004%	0	0.0000%
493	1,618,150	0.6692%	165,544	0.7690%
494	501,392	0.2074%	44,178	0.2052%
495	674,481	0.2789%	60,357	0.2804%
496	163,389	0.0676%	16,198	0.0752%
497	3,505	0.0014%	223	0.0010%
498	51,508	0.0213%	968	0.0045%
499	14,477	0.0060%	1,220	0.0057%

	Current Methodology		High 5 Proposal	
Delivery Point ID	**Total of 12 monthly Network Charge Determinants (KW)**	**Share of Total Network Charge Determinants**	**Average of Coincident Peak Demand on the 5 highest peak days in 2011 (KW)**	**Share of Total High-5 Charge Determinants**
500	253,012	0.1046%	21,145	0.0982%
501	434,132	0.1795%	38,260	0.1777%
502	379,744	0.1571%	34,649	0.1610%
503	12,896	0.0053%	342	0.0016%
504	590,442	0.2442%	41,858	0.1944%
505	2,696,345	1.1151%	281,902	1.3095%
506	735,714	0.3043%	76,213	0.3540%
507	317,083	0.1311%	17,576	0.0816%
508	817,311	0.3380%	60,218	0.2797%
509	0	0.0000%	0	0.0000%
510	178,345	0.0738%	16,952	0.0787%
511	39	0.0000%	0	0.0000%
512	5,831	0.0024%	304	0.0014%
513	268,264	0.1109%	25,072	0.1165%
514	2,328,854	0.9632%	249,793	1.1604%
515	1,561,934	0.6460%	147,281	0.6842%
516	1,288,467	0.5329%	144,983	0.6735%
517	15,006	0.0062%	156	0.0007%
518	52,561	0.0217%	2,801	0.0130%
519	157,457	0.0651%	15,060	0.0700%
520	60,013	0.0248%	4,435	0.0206%
521	2,219	0.0009%	0	0.0000%
522	813,834	0.3366%	89,210	0.4144%
523	612,196	0.2532%	66,821	0.3104%
524	325,031	0.1344%	23,807	0.1106%
525	199,190	0.0824%	16,408	0.0762%
526	361,355	0.1494%	32,518	0.1511%
527	447,751	0.1852%	30,887	0.1435%
528	907,905	0.3755%	79,485	0.3692%
529	65,654	0.0272%	3,683	0.0171%
530	974,025	0.4028%	76,575	0.3557%
531	86	0.0000%	0	0.0000%
532	16,929	0.0070%	0	0.0000%
533	141,199	0.0584%	8,481	0.0394%
534	32,566	0.0135%	2,025	0.0094%
535	218,967	0.0906%	15,113	0.0702%
536	50,396	0.0208%	3,309	0.0154%
537	2,022	0.0008%	0	0.0000%
538	289,775	0.1198%	26,599	0.1236%
539	1,192,803	0.4933%	118,096	0.5486%
540	299,058	0.1237%	32,446	0.1507%

	Current Methodology		High 5 Proposal	
Delivery Point ID	**Total of 12 monthly Network Charge Determinants (KW)**	**Share of Total Network Charge Determinants**	**Average of Coincident Peak Demand on the 5 highest peak days in 2011 (KW)**	**Share of Total High-5 Charge Determinants**
541	25,041	0.0104%	1,127	0.0052%
542	15,462	0.0064%	634	0.0029%
543	611	0.0003%	0	0.0000%
544	59,748	0.0247%	3,485	0.0162%
545	426,714	0.1765%	44,808	0.2081%
546	253,237	0.1047%	17,644	0.0820%
547	1,521,628	0.6293%	116,005	0.5389%
548	1,358,292	0.5618%	113,134	0.5255%
549	631,825	0.2613%	55,091	0.2559%
550	2,181	0.0009%	0	0.0000%
551	646,909	0.2675%	50,476	0.2345%
552	185,480	0.0767%	16,665	0.0774%
553	65,251	0.0270%	6,361	0.0295%
554	959,335	0.3968%	108,083	0.5021%
555	319,546	0.1322%	24,055	0.1117%
556	464,055	0.1919%	47,714	0.2216%
557	298,878	0.1236%	24,278	0.1128%
558	147,430	0.0610%	12,668	0.0588%
559	684,233	0.2830%	62,131	0.2886%
560	105,671	0.0437%	5,872	0.0273%
561	50,404	0.0208%	1,787	0.0083%
562	96	0.0000%	0	0.0000%
563	0	0.0000%	0	0.0000%
564	1,279,843	0.5293%	120,285	0.5588%
565	94,427	0.0391%	7,846	0.0364%
566	5,212	0.0022%	274	0.0013%
567	404,255	0.1672%	37,170	0.1727%
568	778,884	0.3221%	69,545	0.3231%
569	11,774	0.0049%	547	0.0025%
570	662,140	0.2738%	58,634	0.2724%
571	393,521	0.1627%	45,822	0.2129%
572	28,736	0.0119%	2,219	0.0103%
573	203,135	0.0840%	19,274	0.0895%
574	228,953	0.0947%	22,625	0.1051%
575	376,851	0.1559%	40,255	0.1870%
576	350,645	0.1450%	36,414	0.1692%
577	206	0.0001%	17	0.0001%
578	42,139	0.0174%	228	0.0011%
579	131,020	0.0542%	12,677	0.0589%
580	283,749	0.1174%	31,803	0.1477%
581	318,467	0.1317%	29,691	0.1379%

	Current Methodology		High 5 Proposal	
Delivery Point ID	**Total of 12 monthly Network Charge Determinants (KW)**	**Share of Total Network Charge Determinants**	**Average of Coincident Peak Demand on the 5 highest peak days in 2011 (KW)**	**Share of Total High-5 Charge Determinants**
582	336,357	0.1391%	33,560	0.1559%
583	273,417	0.1131%	25,400	0.1180%
584	267,773	0.1107%	25,379	0.1179%
585	51,473	0.0213%	3,428	0.0159%
586	975,868	0.4036%	89,052	0.4137%
587	1,738	0.0007%	0	0.0000%
588	417,426	0.1726%	33,432	0.1553%
589	87,476	0.0362%	7,856	0.0365%
590	3,243	0.0013%	44	0.0002%
591	74,923	0.0310%	7,119	0.0331%
592	252,607	0.1045%	21,820	0.1014%
593	3,417	0.0014%	0	0.0000%
594	250,370	0.1035%	29,600	0.1375%
595	873,027	0.3611%	84,135	0.3908%
596	13,928	0.0058%	554	0.0026%
597	486,767	0.2013%	23,336	0.1084%
598	82,350	0.0341%	7,640	0.0355%
599	25,541	0.0106%	1,555	0.0072%
600	2,427	0.0010%	0	0.0000%
601	525,782	0.2174%	51,876	0.2410%
602	108,776	0.0450%	9,318	0.0433%
603	15,547	0.0064%	800	0.0037%
604	743	0.0003%	0	0.0000%
605	2,739	0.0011%	0	0.0000%
606	304,746	0.1260%	31,802	0.1477%
607	1,296	0.0005%	10	0.0000%
608	205	0.0001%	0	0.0000%
609	4,458	0.0018%	68	0.0003%

c) This response is provided by the IESO.

Implementation costs of the High Five Proposal based on the basic design features currently contemplated for this proposal is estimated to be between $50,000 - $100,000. A key assumption in the basic design is that all customers or customer groups are treated the same. The cost and complexity of the implementation will increase if special or additional unique design features of the High Five Proposal are approved (e.g., exemption or special conditions for certain customers or customer groups).

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #64 List 1

Interrogatory

Issue 8.1: Is it appropriate to implement "AMPCO's High 5 Proposal" in place of the status quo charge determinants for Network service?

Reference: Exhibit H1, Tab 3, Schedule 1, Attachment 1, Sections 2.1 and 2.2

a) With respect to page 3, please explain why the "second criterion" is considered a "demand ratchet" when its value is also based on the actual load in the billing period.
b) With respect to page 9, can Power Advisory provide its views regarding Dr. Sen's suggestion that the fact the coefficients have the right sign and are statistically significant is "more important" than the fact the R-squared values were low?

Response

The response to parts a and b are provided by Power Advisory.

a) Power Advisory considers the pricing mechanism to be a form of demand ratchet because the 85% of the non-coincident peak may "ratchet" up the demand determinant used for billing purposes relative to the monthly coincident peak value.

b) In judging the results of econometric estimations, Power Advisory considers that the importance of the criteria depends on the purpose to which the results will be put. For example, if the purpose is forecasting, the criterion of most interest would be the variance observed by splitting the sample period and using the estimated structure to forecast part of the sample.

   In this case, the purpose is to produce an accurate estimate of the structural coefficients so they can be used to quantify reaction to a price change. As a minimum for such use, the coefficient estimates must have the right sign and be significantly different from zero. Being significantly different from zero only means that the null hypothesis (that there is no relation between the independent and dependent variables) is rejected; it does not say anything about whether the estimated coefficient is a good estimator of the true value.

   To be a good estimator, the estimator should be unbiased; that is, the expected value of the coefficient should be the (unknown) actual population value. If the estimators are unbiased, having a low R-squared does not by itself degrade their usefulness. However, the low R-squared can result from specification errors, and in particular from omitted variables, which can bias the estimators.

In the case of the AMPCO demand equations, the existence of multicollinearity by itself means that the estimators are not unbiased and the presence of omitted variables likely also induces bias. In the presence of such bias, one way to judge the usefulness of such estimators is to estimate them with different time frames or different specifications. Coefficients that are stable with different estimations are often better accepted.

Whether these estimators are useful for their purpose is a matter for judgment of the user, taking into account these criteria and others that the researcher considers. Power Advisory considers that these econometric results are useful as indicators but not definitive point estimators, given both that they are not highly stable and that there is evidence that they are biased.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #65 List 1

Interrogatory

Issue 8.1: Is it appropriate to implement "AMPCO's High 5 Proposal" in place of the status quo charge determinants for Network service?

Reference: Exhibit H1, Tab 3, Schedule 1, Attachment 1, Section 2.3.1 and Section 6

a) Please provide the evidence/analysis that Power Advisory relied on to support the comments/conclusions presented in the first paragraph of Section 6.1 about load growth by customer class.

a) With respect to pages 69-70, what is the basis for Power Advisory's conclusion that for four of the six local area supply projects there is no potential for the High 5 Proposal to defer transmission investment?

b) With respect to pages 69-70, did Power Advisory investigate the degree to which the timing of the peak load requirements driving the need for additional capacity in the Woodstock and Guelph areas was consistent with the timing of the overall system peak? If yes, what were the results?

c) Could Hydro One Networks please provide a revised version of Table 18 that indicates the annual Development spending (by type) that will be classified as Network costs by Hydro One Networks' cost allocation methodology.

d) Please comment (by Zone) on the reasonableness of using 1% and/or 2% as the future load growth assumption.

Response

The response to parts a, b and d are provided by Power Advisory.

a) This is based in part on Power Advisory's experience in forecasting electricity demand in Ontario and based on our review of economic forecasts produced by others. For example, from 1991 to 2005, the residential sector grew almost twice as fast as the commercial and industrial sectors. The OPA's forecast in its Integrated Power System Plan has the commercial sector growing about twice as fast as the industrial sector from 2005 to 2015, and the residential sector growing by 1.5 times as fast as the industrial sector.

a) This conclusion is based on our review of the investment drivers for these local area supply projects and discussions with Hydro One transmission planners. The investment drivers for four of these six projects aren't attributable to load growth. These projects and the investment drivers are: (1) the rebuild of the Burlington TS 115 kV Switchyard which is under-rated with respect to short circuit withstand rating and/or ampacity as a result of generation additions in the area. Therefore, the need for this project is driven by generation additions, not load growth; (2) three Toronto Area Station Upgrades for Short Circuit Capability which are driven by various components being at the end of their useful life and the need to comply with the requirements of the Transmission System Code and to allow distributed generation to connect to the transmission grid in Toronto; and (3) the Midtown Transmission Reinforcement Plan which would replace aging facilities and provide adequate supply capacity to meet future load growth. With no direct customers in the City of Toronto this load growth wouldn't be offset by the load shifting from the High Five proposal.

b) Power Advisory didn't have such load data available. However, to the degree that the need for additional transmission capacity in the Woodstock and Guelph areas is driven by local peaks that differ in timing from the overall system peak then the High 5 Proposal wouldn't defer such investments.

c)

Transmission Capital Expenditures: Development

($ Million) \ (%)	2010	% of Total	2011	% of Total	2012	% of Total	Allocation to Network Pool
Inter-Area Network Transfer Capability	424.5	75.0%	303.4	42.0%	116.7	21.8%	100%
Local Area Supply Adequacy	63.4	11.2%	163.3	22.6%	116.5	21.8%	0%
Load Customer Connection	48.1	8.5%	130.6	18.1%	124.2	23.2%	0%
Generation Customer Connection	10.8	1.9%	44.5	6.2%	23.3	4.4%	0%
Enabling Facilities	0.0	0.0%	0.1	0.0%	16.9	3.2%	0% Note 1
Bulk& Regional Transmission	0.0	0.0%	4.5	0.6%	22.6	4.2%	100%
Station Upgrades & Additions for Renewables	0.0	0.0%	33.6	4.6%	64.5	12.1%	Up to 100% Note 2
Protection & Control for Distribution Connected Generation	0.6	0.1%	11.4	1.6%	36.0	6.7%	Up to 20%
Smart Grid	1.4	0.2%	7.8	1.1%	6.8	1.3%	0%
Performance Enhancement	1.7	0.3%	4.0	0.6%	4.0	0.7%	0%
Risk Mitigation	15.8	2.8%	20.0	2.8%	3.2	0.6%	100%
Total	566.3	100.0%	723.2	100.0%	534.7	100.0%	

Note 1: Enabling facilities are expected to be in the Line and Transformation Connection Pools.
Note 2: Most of these facilities would be Network; however, in situations such as Network in-line breakers, any portions of the costs that represent the customer's minimum connection requirements would be the responsibility of the customer.

d) The IPSP provided a long term demand forecast by zone. (EB-2007-0707, Exhibit D, Tab 1, Schedule 1, Attachment 2, page 7) Power Advisory believes that the underlying level of demand presented in the IPSP is no longer realistic given the dramatic decline in electricity demand since the release of the IPSP. However, the forecast of the relative growth rates for different zones continues to represent a reasonable basis for assessing likely demand growth rates for different zones because the factors driving medium-term growth in the different zones have not changed as much as the factors which produced the current low level of demand. Furthermore, no other forecast of relative growth rates is available. The compound annual growth rates (CAGRs) of zonal peaks at the time of the system summer peak from the IPSP are shown in the table below.

Zone	Compound Annual Growth Rate
Northwest	-1.5%
West	0.7%
Northeast	-0.7%
Essa	1.3%
Ottawa	1.1%
East	0.7%
Toronto	1.5%
Niagara	0.5%
Southwest	1.1%
Bruce	2.0%
Ontario	1.0%

These CAGRs suggest that a 1% load growth rate is likely to be high for the Northwest, West, Northeast, East, and Niagara zones, but would be appropriate for the Essa, Ottawa, and Southwest zones. Furthermore, a 2% load growth rate may be appropriate for the Toronto/GTA zone. The Bruce Zone has no direct customers.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #66 List 1

Interrogatory

Issue 8.1: Is it appropriate to implement "AMPCO's High 5 Proposal" in place of the status quo charge determinants for Network service?

Reference: Exhibit H1, Tab 3, Schedule 1, Attachment 1, Section 2.3.2 and Section 3.1

a) If the peak hour can currently occur anywhere between 1 PM and 6 PM (inclusive) and the introduction of the High 5 Proposal encourages shifting away from the peak hours, doesn't this:
   - Increase the likelihood that the High 5 Peaks will occur in the shoulder hours of 1 PM and 6 M? If not, why not?
   - Create the possibility that the High 5 Peaks will occur outside the 1PM to 6 PM window? If not, why not?

Response

This response is provided by Power Advisory.

a)
   - Yes. The High 5 Proposal as well as demand response (DR) programs in general will encourage shifting of when the peak typically occurs.

   - Yes, as the penetration of DR programs and time of use pricing increases there is a greater likelihood that the combined effect of these programs and the High 5 Proposal will cause the High 5 Peaks to occur outside the 1 PM to 6 PM window.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #67 List 1

Interrogatory

Issue 8.1: Is it appropriate to implement "AMPCO's High 5 Proposal" in place of the status quo charge determinants for Network service?

Reference: Exhibit H1, Tab 3, Schedule 1, Attachment 1, Sections 2.3.2 and 3.2

a) Please provide copies of the Deal and Mountain (Footnote #103); the Cheng and Mountain (Footnote #106); and the Fraser Institute (Footnote #107) articles referenced in Section 3.2.
b) With respect to pages 35-36, please confirm Power Advisory's view that the appropriate elasticity estimate to be used is the elasticity of substitution (between peak and off-peak) as opposed to a peak period own-price elasticity estimates.
c) Is it reasonable to expect that the value for the elasticity of substitution between peak and off-peak electricity will vary depending upon the definition of "peak" and "off-peak"? If not, why not?
d) Please confirm that the range referenced for the Deal and Mountain results are for the "elasticity of substitution" between peak and off-peak electricity. Also, please confirm the definition of "peak" and "off-peak" used.
e) Please confirm that the range referenced for the Cheng and Mountain results are for the "elasticity of substitution" between peak and off-peak electricity. Also, please confirm the definition of "peak" and "off-peak" used.
f) Please confirm that the elasticity estimates quoted from the Fraser Institute Technical Paper are own-price elasticities as opposed to elasticities of substitution. If not, what were the definitions of "peak" and "off-peak" used in the Paper?
g) With respect to Table 7, please confirm that the various studies referenced used different definitions for "peak" and "off-peak". If available, please provide the definition of "peak" used for each study.
h) Please comment on the extent to which the time of use pricing in the various sources referenced was "voluntary" or "mandatory" and if this is likely to affect the observed value for the elasticity of substitution.

Response

The response to all parts of this interrogatory is provided by Power Advisory.

a) See Exhibit I, Tab 9, Schedule 56 for the Cheng and Mountain report.
The Deal and Mountain study is available from the IESO website at:
http://www.ieso.ca/imoweb/marketsAndPrograms/MEAR_publications.asp

The Fraser Institute study is available on the Fraser Institute website at: http://www.fraserinstitute.org/publicationdisplay.aspx?id=13267&terms=technical+paper

b) This is confirmed. The appropriate elasticity estimate to be used is the elasticity of substitution.

c) Yes, it is reasonable to expect that. The nature and cost of the customer's reaction can be expected to change as the length of the peak period changes, which would change the elasticity. One of the studies referenced found that "Price response is highest for high prices of short duration, and falls rather dramatically as the duration of high prices increases."[1]

d) Confirmed that the results are for elasticities of substitution. The range referenced is Deal and Mountain's summary of the estimated elasticities of substitution they found from their survey of studies in the literature. These studies included a mix of conditions including time of use pricing and Real Time Pricing (RTP), under which customers are informed a day in advance of the prices that will apply during the next day's peak period. There is therefore no single definition of "peak" and "off-peak" used for these studies.

e) Confirmed that the results are for elasticities of substitution. The Cheng and Mountain study analyzed the results of Ontario Hydro's TOU rates from 1989-1991. The peak period was defined as 7 AM – 11 PM (16 hours) on weekdays.

f) Confirmed that the elasticities from the Fraser Institute paper are own-price elasticities.

g) Confirmed that the various studies used different definitions. Study #2 used eight different definitions of peak with durations ranging from three to five hours. Study #4 analyzed a form of day-ahead pricing in which customers were given firm day-ahead prices for each hour of the next day. Other definitions are not available.

h) Details are not available for most of the studies referenced. In study #2, Real Time Pricing was one among three pricing options customers could choose. In #4, participation was voluntary. Customers who volunteer for such programs are likely to be those who expect to be able to adjust their load to take advantage of the lower-price periods, which implies that their elasticity is higher than that of non-volunteers.

[1] Richard Boisvert, Peter Cappers, Bernie Neenan, and Bryan Scott, "Industrial and Commercial Customer Response to Real Time Electricity Prices", Neenan Associates, December, 2004, pg. 3.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #68 List 1

Interrogatory

Issue 8.1: Is it appropriate to implement "AMPCO's High 5 Proposal" in place of the status quo charge determinants for Network service?

Reference: Exhibit H1, Tab 3, Schedule 1, Attachment 1, Sections 3.1 and 3.3

a) Please confirm that the various shadow prices set out in Table 3 are each associated with a different definition of "peak" hours (i.e., ranging from 60 hours to 200 hours).
b) What definition of "peak" hours was used to determine the Average Peak HOEP set out in Table 11 and how does this compare with the "peak" definitions used to determine the shadow prices for transmission in Table 3.
c) Please confirm that this definition of peak (per part (b)) was used to determine the "peak demand" for each industry as set out in Table 12 and the values in Table 12 are the average demand during this peak period (as opposed to the peak demand in the peak period).
d) Table 11 uses a GA "price" of $3.47 / GWh. What is the source of this value? What was the value for 2009?
e) With respect to Table 12, what does the Low Demand Shift value represent, i.e., is it the result of using the low elasticity value in combination with the low High 5 Shadow price value? Similarly, what do the Centre and High Demand Shift values represent?
f) With respect to Table 12, please provide an illustrative calculation (using the Pulp and Paper sector) showing precisely how the demand shift values were calculated using the assumed elasticity estimates.
g) The formula for the elasticity of substitution involves off-peak prices and quantities as well as those for the peak period (see page 35 of the Power Advisory Report). What off-peak prices and loads were used in the estimation of the demand shifts shown in Table 12 and how were they determined?
h) Please re-do Table 12 using a current (implicit) shadow price for transmission of $102.80 (per page 48).

Response

The response to all parts of this interrogatory are provided by Power Advisory.

a) Confirmed that the shadow prices set out in the top half of Table 3 (Power Advisory's calculations) are each associated with a different definition of peak hours ranging from 60 to 200 hours.

b) These data are from the IESO and use its definition of peak, which is the 16 hours ending 8 to 23 on weekdays. The definitions used to establish the shadow prices are not specific; they would apply to any set of hours that customers view as potential peak hours.

c) For the calculations in Table 12, we assumed specific peak hours for each of the high, center and low cases. For the high case, the assumption was that the customer would shift load for four hours on fifteen days. For this case, we used the hours ending 2-5 PM. For the central case, the assumption was that the customer would shift load for six hours on twenty days. For this case, we used the hours ending noon-5 PM. For the low case, the assumption was that the customer would shift load for 8 hours on 25 days. For this case, we used the hours ending 10 AM to 5 PM.

d) Power Advisory advises that the correct price that should have been referenced in the question is $3.47/MWh a shown on Table 11 of the Power Advisory Report. This value is the average of the Global Adjustment for the months of June, July and August 2008, as per the IESO's Monthly Market Reports. The average value for all of 2009, as shown in the IESO Monthly Market Report for December 2009, was $30.56 per MWh.

e) Yes, the low result is the result of using the low elasticity value in combination with the low High 5 shadow price value. It also uses demand and peak prices for the appropriate intervals. The center and high demand shift values similarly represent the central and high shadow prices with the central and high elasticity values, respectively.

f) The formula and an example calculation using the pulp and paper industry is provided below.

Formula and example calculation of load shifting, using pulp and paper industry

High case example used

INPUTS						
	Peak	Off-Peak	**Notation**		**Data sources**	
Load (MWh per Hour)	439.3	594.4	pkld	opkld	IESO	IESO
Avg. Price - Base	$105	$60	=ppk(0)	=popk(0)	Table 3	Table 3
Avg. Price - Treatment case	$516	$60	=ppk(1)	=popk(1)	Table 12	Table 3
Number Hours	4	20	=pkhr	=opkhr	High case	
Elasticity of Substitution	0.1		=elas			
CALCULATIONS					**Calculation details**	
Total Daily Load (MWh)	13,644		=tdl		Total daily load is (pkld * pkhr + opkld * opkhr)	
% Change Price	-0.796158054		=deltap		% price change is [(popk(1)/ppk(1)-(popk(0)/ppk(0)]/(popk(0)/ppk(0)	
% Change in Load	-0.079615805		=deltatdl		% load change is (deltap*elas)	
OUTPUT						
	Peak	Off-Peak				
New Load (MWh/Hour)	408.5	600.5	pkld(1)	opkld(1)	New peak load is {tdl*[(pkld*pkhr)/{opkld/opkhr)]}/{1+[((pkld*pkhr)/{opkld/opkhr))*(1+deltatdl)}/pkhr	
					New off-peak load is [tdl-(pkld(1)*pkhr)]/opkhr	
Load Reduction (MWh/Hour)	30.8	-6.2			Peak load reduction is (pkld-pkld(1)); off-peak load reduction is (opkld-opkld(1))	
% Load Reduction	7%	-1%				

g) For each of the three cases, we computed the average on-peak and off-peak demand for each of those periods. As a result, for each case we had different levels of off-peak demand. The off-peak price was $59.75/MWh, computed by Power Advisory from the IESO data.

h) See Table below.

Demand Shifts

Industry	Peak Demand (MW)	Implicit Base Price ($/MWh)	Elasticities of Substitution Low	Elasticities of Substitution Center	Elasticities of Substitution High	High Five Shadow Prices ($/MWh) Low	High Five Shadow Prices ($/MWh) Center	High Five Shadow Prices ($/MWh) High	Demand Shift (MW) Low	Demand Shift (MW) Center	Demand Shift (MW) High
Pulp and Paper	439.3	$ 102.80	0.050	0.074	0.100	$ 154.20	$ 257.00	$ 411.20	-10	-19	-31
Iron and Steel	536.1	$ 102.80	0.080	0.120	0.160	$ 154.20	$ 257.00	$ 411.20	-18	-35	-59
Metal Mining	517.2	$ 102.80	0.060	0.107	0.155	$ 154.20	$ 257.00	$ 411.20	-13	-30	-55
Non-metallic minerals	65.5	$ 102.80	0.030	0.050	0.070	$ 154.20	$ 257.00	$ 411.20	-1	-2	-3
Petroleum Refining	199.8	$ 102.80	0	0	0.020	$ 154.20	$ 257.00	$ 411.20	0	0	-3
Motor Vehicles	137.7	$ 102.80	0	0	0.020	$ 154.20	$ 257.00	$ 411.20	0	0	-2
Totals	1895.6								-41	-86	-152

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #69 List 1

Interrogatory

Issue 8.1: Is it appropriate to implement "AMPCO's High 5 Proposal" in place of the status quo charge determinants for Network service?

Reference: Exhibit H1, Tab 3, Schedule 1, Attachment 1, Sections 2.3.3 and 5

a) With respect to page 63 and Table 16, please show separately the calculation of the on-peak cost reduction and the off-peak increase.

b) What is Power Advisory's assumption regarding the off-peak hours to which the load is shifted? For example, does Power Advisory assume the load is shifted to i) the off-peak period as defined by the current transmission tariff (7 PM to 7 AM), ii) other hours in the current transmission tariff's on-peak period but outside the window assumed to capture the High 5 Hours; or iii) all hours outside the High 5 Hours?

c) Given that the supply curve is not smooth (per Figure 4), does the selection of the off-peak hours the load is assumed to shift to have an impact on the Total Cost change?

d) What would the Total Cost Change under the High Case if:
   - The load shifted just to the remaining on-peak hours (i.e., 7 AM to 7 PM) in the same day,
   - The load shifted to the off-peak hours in the same day.

Response

The response to all parts of this interrogatory are provided by Power Advisory.

a) These are results from the proprietary Power Advisory model. The calculations cannot readily be shown because they come from the model.

b) Power Advisory assumes that the load is shifted into the same number of off-peak hours as it was shifted out of on-peak hours. The hours it is shifted into start at midnight; that is, with the hour ending 1. For example, for the high case, the load is shifted into the hours ending 1-4 because it was shifted out of 4 peak hours.

c) Power Advisory has not investigated this question, but we expect that the hours to which load is shifted to would affect the Total Cost change. Specifically, we expect that selecting off-peak hours which are likely to have lower load levels such as we have done will result in a smaller price increase.

d) Power Advisory initiated the analysis required to answer this question but has been unable to complete it in the time available. For this analysis, Power Advisory is using the same time period for shifting load out and the same base model, so the benefits (lower prices during periods when load is shifted out) will be the same for these cases as for the High Case presented in our Report.

Power Advisory expects that the costs (higher prices during periods when load is shifted in) would be higher in the first case above than in the High Case in our Report, since the period into which the load will be shifted would be one where prices are higher and the move up the supply curve, and hence the price increase, would be greater than in our Report. The Total Cost Change would therefore be lower than in our Report.

For the second case above, Power Advisory's analysis shifts the load into the period from 8 PM to 11 PM (hours 20 to 23), which would be the first off-peak (by the definition given) hours available in the same day after the load is shifted off. Power Advisory expects that the cost could be higher in the second case above than in our Report, again since the period to be shifted into is one of higher demand than the analysis in our Report. The Total Cost Change would therefore be lower than in our report. This expectation is less strong than for the first case, since the period shifted into may not have as steep a supply curve, and as a result a lower price increase than expected in the first case.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #70 List 1

Interrogatory

Issue 8.1: Is it appropriate to implement "AMPCO's High 5 Proposal" in place of the status quo charge determinants for Network service?

Reference: Exhibit H1, Tab 3, Schedule 1, Attachment 1, Section 7

a) Please comment on the extent to which, in Power Advisory's view, there is an overlap between the load shifting targeted by Demand Response programs (e.g., those offered by the OPA) and that which would result from the adoption of the High 5 Proposal
b) If an overlap does exist, what are Power Advisory's views as to which approach is more effective in reducing demand when supply is tight and/or market prices are high.

Response

The response to parts a and b are provided by Power Advisory.

a) Power Advisory believes that there is a potential overlap between the OPA's Demand Response programs and the load shifting that would be promoted by the High 5 proposal.

b) Power Advisory believes that targeted demand response programs will be more effective at promoting load reductions when supply is tight or market prices are high, in part because such programs can call for load reductions during these periods. In contrast, under the High 5 proposal customers must correctly anticipate the system peak and depending on supply conditions these might not be times when supplies are tight or prices high

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #71 List 1

Interrogatory

Issue 9.1: **Are the OM&A and capital amounts in the Green Energy Plan appropriate and based on appropriate planning criteria?**
Issue 9.2: **Are Hydro One's accelerated cost recovery proposals for the Bruce-to-Milton line and for Green Energy projects appropriate?**

Vulnerable Energy Consumers Coalition (VECC)INTERROGATORY #71

References: i) Exhibit A/Tab 11/Schedule 4/Page 8
ii) Exhibit A/Tab 11/Schedule 4/Page 9 Table 1

Preamble: Projects driven by this Green Energy Plan will constitute a major portion of the Transmission Development capital work program in the near term, 2010 – 2014 and over the longer term, 2015 – 2020. Hydro One expects to spend $2.5B in the 2010 – 2014 timeframe and an additional $4.5B in the 2015 – 2020 period on these investments.

a) Provide a list of Major Capital Investments 2010-2014 indicating capital investment, year to be completed, requirement(s) for OEB approval and transmission capacity.
b) Relate/cross reference the list to the 2011/2012 capital program for which approval is sought in this application.

Response

Please see Exhibit I, Tab 1, Schedule 99, Exhibit I, Tab 1, Schedule 104 and Exhibit I, Tab 1, Schedule 107.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #72 List 1

Interrogatory

Issue 9.1: **Are the OM&A and capital amounts in the Green Energy Plan appropriate and based on appropriate planning criteria?**
Issue 9.2: **Are Hydro One's accelerated cost recovery proposals for the Bruce-to-Milton line and for Green Energy projects appropriate?**

Reference: Exhibit A/Tab 11/Schedule 4/Page 47 Exhibit A/Tab 11/Schedule 5/Page 10 and Table 3

Preamble: However, given the materiality of these development costs, currently projected at $160 million in total (see Exhibit C1, Tab 2, Schedule 4) Hydro One is considering the need for a mechanism to recover these costs as incurred and might propose a rate rider mechanism.

a) Is Hydro One proposing to apply under the current Docket for either a new deferral account and/or Rate rider for GEA projects
b) If so, provide details of how the $160 million of development costs would be recovered from ratepayers

Response

a) Hydro One is not proposing to apply for a rate rider mechanism to recover the costs at this time.

b) N/A

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #73 List 1

Interrogatory

Issue 9.1: **Are the OM&A and capital amounts in the Green Energy Plan appropriate and based on appropriate planning criteria?**
Issue 9.2: **Are Hydro One's accelerated cost recovery proposals for the Bruce-to-Milton line and for Green Energy projects appropriate?**

Reference: Exhibit A/Tab11/Schedule 5/page 5

a) Provide an update on the status of approvals and percentage completion of the BxM project.
b) What is the current anticipated in-service date?
c) What is the Total Capital cost (or current estimate)?

Response

a) & b) Please see the response in I-1-121.
c) Please see the response in I-10-28.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #74 List 1

Interrogatory

Issue 9.1: Are the OM&A and capital amounts in the Green Energy Plan appropriate and based on appropriate planning criteria?
Issue 9.2: Are Hydro One's accelerated cost recovery proposals for the Bruce-to-Milton line and for Green Energy projects appropriate?

References: i) Exhibit A/Tab 11/Schedule 5/Page 4/Table 1
ii) Exhibit A/Tab 11/Schedule 5/Page 8/ Table 2
iii) Exhibit A/Tab 12/Schedule 2/Page 6/Table 6

a) For the BxM project, provide a calculation on based on Table 2. of the 2011 and 2012 CWIP/AFUDC using Hydro One's All Corporate Mid-Term Average Weighted Bond Yield (rather than the full cost of capital)
b) Explain why other than GEA projects, Accelerated CWIP treatment is appropriate?
c) Explain why Hydro one should recover the full cost of capital including ROE for "standard" transmission assets that are not used or useful?
d) Explain in more detail why BxM qualifies for accelerated CWIP treatment.

Response

a) Please see Table 1 at the end of this response.

b) The Board's *Report on the Regulatory Treatment of Infrastructure Investment*, at the top of page 13, noted that "The alternative mechanism may also be available to other types of projects in appropriate circumstances." Hydro One believes that the Bruce to Milton project has similar characteristics to the Green Energy Act projects that the Board had in mind in formulating the Report, insofar as Bruce to Milton is a large, capital-intensive project requiring extensive consultation, land acquisition and approvals activities, all of which are subject to the kinds of risks that the Board considered. On that basis, the Bruce to Milton project is being proposed as one of the "other" qualifying projects.

c) Hydro One is proposing that the usual ratemaking approach apply in respect of the return on CWIP costs – i.e., costs in rate base earn the full cost of capital. Please see the response to Staff Interrogatory # 122 for an explanation of why the CWIP in ratebase method, despite using an all-in return, is less expensive in this case on a lifetime revenue requirement basis, than the standard AFUDC approach.

For the reasons provided there, Hydro One believes that using the all-in cost of capital is appropriate for CWIP in ratebase.

d) See the response to part b).

Table 1

BxM Project "Accelerated Cost Recovery of CWIP" Revenue Requirement Impact Using All Corporate Mid-Term Average Weighted Bond Yield

($ millions)

Cash Flows ($M)	2009 Life To-Date	2010	2011	2012*	Total (incl Future Years)
Annual Expenditures	202.6	191.0	184.4	94.3	695.5
CWIP (Year End)	202.6	393.6	577.9	0.0	
"Accelerated Cost Recovery of CWIP" Rate Base			485.8	289.0	

% Return on Rate Base	2011	2012
All Corporate Mid-Term Average Weighted Bond Yield*	5.60%	6.10%

** See Table 1 of D1-4-1, p. 1*

	2011	2012
$ Return on Rate Base	27.2	17.6
Tax Rate	28.25%	26.25%
Income Tax	0.0	0.0

Revenue Requirement Impact			2011	2012
OM&A			0.0	0.0
Depreciation			0.0	0.0
Return on Debt			27.2	17.6
Return on Equity			0.0	0.0
Income Tax			0.0	0.0
Total			27.2	17.6

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #75 List 1

Interrogatory

Issue 9.1: Are the OM&A and capital amounts in the Green Energy Plan appropriate and based on appropriate planning criteria?
Issue 9.2: Are Hydro One's accelerated cost recovery proposals for the Bruce-to-Milton line and for Green Energy projects appropriate?

References: Exhibit A/Tab 11/Schedule 5/Page 6 and Table 2

a) Hydro One Networks claims that the accelerated cost recovery will lower the overall cost to ratepayers over the life of the facility. Please provide a schedule that sets out the annual revenue requirement impact starting in 2011 and extending for the life of the facility (similar to impact shown in Table 2 for 2011 & 2012) for two cases: i) BxM project with normal current treatment of CWIP and ii) BxM project with the proposed accelerated cost recovery of CWIP. Note: For post 2012 assume the cost of debt and equity is the same as that in 2012.
b) For both cases in part (a) please calculate the 2011 NPV of the revenue requirement impact using Hydro One Networks' weighted average cost of capital.

Response

a) Please see Exhibit I, Tab 1, Schedule 122.

b) Please see Exhibit I, Tab 1, Schedule 122.