Association of Major Power Consumers of Ontario (AMPCO) INTERROGATORY #1 List 1

Interrogatory

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

Ref: Ex H1/Tab 5/Schedule 1/Page 2

Please provide the following information with respect to Hydro One's forecast of export transmission service revenues:

A) A list of export transmission service revenues, by year, for the years 2005-2009.

B) The original Independent Electricity System Operator (IESO) transmission export revenue forecasts for the years 2005-2009.

C) A detailed description of the forecasting methodology used by the IESO to forecast export transmission revenues.

D) In a format similar to what Hydro One provides to confirm its load forecast accuracy (Ex A/Tab 12/Schedule 3/Page 21/Table 5), please illustrate the historical forecast accuracy for the Hydro One/IESO export transmission tariff revenue forecasts.

Response

The response to parts B) and C) are provided by the IESO with input from Hydro One to part B).

A) Revenues received for export transmission service for the year 2005 to 2009 are as follows:

	2005	2006	2007	2008	2009
M$	12.0	13.3	14.1	24.6	16.8

B) The IESO doesn't forecast transmission export revenue; however, the energy export forecasts were provided by the IESO for the years 2005-2009, as follows:

	2005	2006	2007	2008	2009
TWh	5.8	8.6	10.4	12.3	6.7

The export revenue forecasts assumed by Hydro One in its Transmission Applications are as follows:

	2005	2006	2007 (note 1)	2008 (note 1)	2009 (note 2)
TWh	-	-	12	12	12

Note 1: Forecasts based on the actual 2005 level of exports as indicated in EB-2006-0501, Exhibit H1, Tab 5, Schedule 3, page 2, Updated February 23, 2007.

Note 2: Forecast based on export volumes included in the IESO's 2008-2010 Business Plan filed as part of the IESO's 2008 Rate Submission in Proceeding EB-2007-0816:
(http://www.rds.oeb.gov.on.ca/webdrawer/webdrawer.dll/webdrawer/rec/19076/view/IESO_2008_Fees_Business_Plan_2008-2010_Sept.27.07_20071102.PDF)

C) The IESO forecast of export volumes for the 2005 forecast year was based on the previous 5-year (2000-2004) average of monthly exports. For the 2006-2008 forecast years, the export forecasts were based on 3-year moving averages of monthly exports.

For the 2009 forecast year, two adjustments were made to the 3-year moving average model used in the prior years. This was done in recognition of anticipated changes in market and system conditions that were expected to impact export volumes going forward. The two adjustments are described below:

i) The historical export data used in the 3-year moving average was limited to exports net of linked wheels. This was done in recognition of the relatively high volume of linked wheels experienced in the first half of 2008, which subsequently returned to normal levels following Federal Energy Regulatory Commission approval on August 21, 2008 of a New York Independent System Operator (NYISO) temporary proposal prohibiting the scheduling of external transactions over eight specified circuitous paths. This change to the forecast methodology was made because the high volume of linked wheels experienced in the first half of 2008 was not expected to reoccur in 2009. Furthermore, the export volumes associated with linked wheels prior to 2008 had been insignificant.

ii) Electricity exports in 2009 were expected to be lower as a result of government-directed limits on emissions from Ontario's coal-fired generation plants. The IESO anticipated that the reduction in exports due to coal-fired emissions restrictions for 2009 would be approximately 50% of the export forecast based on the 3-year moving average

Going forward, it is possible that the methodology for determining the export forecast will be subject to further revisions as market and system conditions continue to evolve.

D) A comparison of the export transmission service forecast with actual export transmission service revenues, in a format similar to that used in Table 5 of Exhibit A, Tab 12, Schedule 3, is provided below:

Year	**Forecast ETS Revenue ($M)**	**Actual ETS revenue based on IESO invoice ($M)**	**Variance of forecast as percentage of actual**
2005	5.8	12.0	-51.6%
2006	8.6	13.3	-35.1%
2007	12.0	14.1	-15.1%
2008	12.0	24.6	-51.2%
2009	12.0	16.8	-28.6%
Mean			-36.3%

Association of Major Power Consumers of Ontario (AMPCO) INTERROGATORY #2 List 1

Interrogatory

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

Ref: Ex H1/Tab 5/Schedule 1

Please indicate what the export transmission tariff would be for 2011 and 2012, if the tariff had increased in step with Hydro One's revenue increases since it was first implemented in 1999.

Response

The 1999 approved revenue requirement for Ontario Hydro Services Company Inc., the predecessor of Hydro One Transmission, was $1,163.0 million, (Proceeding RP-1998-0001, Transitional Rate Order Transmission, page 3, dated March 31, 1999). The 2011 proposed revenue requirement is $1,445.5 million and for 2012 the proposed revenue requirement is $1,547.4 million, (Exhibit E1, Tab 1, Schedule 1, page 1, Table 1).

If the export transmission tariff had increased in step with Hydro One's revenue increase, the 2011 export transmission tariff would be 1.24 ¢/kWh and in 2012 the export transmission tariff would be 1.33 ¢/kWh.

Association of Major Power Consumers of Ontario (AMPCO) INTERROGATORY #3 List 1

Interrogatory

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

Ref: Ex H1/Tab 5/Schedule 2/Page 3/Note 2

A) Please indicate when the IESO first attempted to negotiate reciprocal export tariff reductions with neighbouring jurisdictions.

B) Please indicate the status of negotiations or agreements between the New York Independent System Operator and the IESO with respect to mutual elimination of export transmission tariffs, including when, in the IESO's estimation, such mutual elimination will occur.

C) If the IESO cannot provide an estimate of when a mutual tariff elimination will occur between New York and Ontario, please indicate the past and current schedule of meetings specifically dedicated to this topic that have been held between the NYISO and the IESO since the IESO report was issued in August of 2009.

D) Please indicate whether the IESO is in current negotiations with jurisdictions other than New York with respect to mutual export tariff reductions and what the status is of these negotiations.

Response

This response is provided by the IESO.

A) B) C) D)

The IESO first initiated discussions with NYISO in 2007. Later it commenced discussions with Hydro Quebec and MISO. These communications continued until mid 2009.

NYISO was receptive to this initiative and indicated it would be interested in discussing it further, pending consultation with NY transmission owners, regulators and its stakeholders.

MISO was not receptive to this initiative; nor was Hydro Quebec. Hydro Quebec advised the IESO in May 2009 that it had no interest in negotiating or participating in any reciprocal arrangement because HQT's tariff was cost-based and applies uniformly to all types of energy transmitted in and out of Quebec.

The IESO intends to follow up with NYISO (and its other neighbors should their level of interest change) on this initiative but not in the near future. The incremental benefit of negotiating an arrangement with NYISO alone is not as great. The IESO will follow-up on this once it completes more immediate initiatives that are required to implement the GEA. In particular, the IESO is currently undertaking initiatives that are necessary to incorporate changes resulting from the GEA, including initiatives designed to integrate increased amounts of renewable generation in a manner that will maintain system reliability and operability (e.g., enable intermittent resources to be treated as dispatchable resources) and which will also contribute to mitigating potential SBG conditions. The IESO proposes that it focus on and complete these efforts before revisiting the matter of ETS tariff elimination with NY, and other neighbours as applicable.

Association of Major Power Consumers of Ontario (AMPCO) INTERROGATORY #4 List 1

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

Ref: Ex G1/Tab 2/Schedule 1
Ref: EB-2006-0501, Ex G1/Tab 1/Schedule 1/Page 5

In the current application, Hydro One refers to the rate making methodology articulated and approved in EB-2006-0501 and EB-2008-0272. The reference to EB-2006-0501 is the articulation of Bonbright's "Principles of Public Utility Rates" for rate making and Hydro One's use of same. The IESO study and summary do not appear to discuss standard rate making principles.

A) Please discuss how the cost allocation and rate design principles that have been approved by the Board have been reflected in the IESO study and recommendation.

B) Please discuss the decision criteria employed by the IESO and whether Hydro One provided any direction to the IESO with respect to how its own rate making principles were to be reflected in the IESO study.

Response

This response is provided by the IESO.

A) The IESO did not undertake a study (nor was it requested to do so) of potential alternatives to the cost allocation principles already approved by the Board and adopted in Ontario in respect of export transmission service. The rate design principles relating to the ETS tariff were approved by the Board in RP-1999-0044. Here the Board endorsed a tariff design that will contribute to maximizing the benefits of integrated regional electricity markets and trades. In particular, the Board noted that "[t]he Board does not accept that the EWT charge should be equal to the domestic charge, as advocated mainly by the environmental groups, since such a charge may frustrate the objective of working toward a larger, open power market." The IESO's recommendation is consistent with the Board's longstanding premise regarding the underlying basis of the export transmission service rate design principles approved by the Board in RP-1999-0044.

B) Please refer to the Section 3.0 of the ETS Tariff Report for an explanation of the decision criteria employed by the IESO. No, Hydro One did not provide any direction to the IESO with respect to how its rate making principles should be reflected in the study.

<u>Association of Major Power Consumers of Ontario (AMPCO) INTERROGATORY #5 List 1</u>

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

Ref: Ex H1/Tab 5/Schedule2/Page 6

Please break out the effects on Ontario consumers and generators in 2011 and 2012 of selecting Option 2, in terms of higher and/or lower costs relative to the status quo.

<u>Response</u>

This response is provided by the IESO.

The study did not consider the effects on consumers (i.e., price impacts) and generators (i.e., variable production costs) for the years 2011 and 2012. The test years in the ETS study were 2010 and 2015. The effects on consumers and generators in selecting Option 2 are as follows:

Cost Effects of selecting Option 2 Relative to the Status Quo

Year	Price effect on Consumers (%)	Cost effect on Generators (Million)
2010	(2.5)	($126)
2015	(1.4)	($325)

Note: 2008 Canadian Dollars

Association of Major Power Consumers of Ontario (AMPCO) INTERROGATORY #6 List 1

Ref: H1/Tab 5/Schedule2/Attachment 1

A) Please indentify any external (i.e., non – IESO or Hydro One) sources of funding for the ETS study, as well as the amount and purpose of the external funding.

B) Please describe how the IESO canvassed for and supported stakeholder involvement for the ETS study, particularly by groups representing customer interests.

C) Appendix B of Attachment 1 lists Hydro Quebec as a stakeholder participant in the ETS study process. Please indicate whether in this study proceeding Hydro Quebec expressed an interest in a mutual elimination of export tariffs and whether discussions have ensued.

Response

This response is provided by the IESO.

A) The scope of the IESO's review was expanded at the behest of stakeholders to consider two additional ETS tariff options (i.e., Unilateral Elimination of the tariff in all hours and only during off-peaks hours) and to review the potential impacts of each of the options on SBG events. Bruce Power contributed $22,000 towards the ETS Tariff Study to help offset the additional cost of expanding the scope of the study. Review of the potential impacts on SBG events was not part of the initial scope of work.

B) The IESO announced that it was undertaking the ETS Tariff Study by way of its weekly bulletin to market participants. Also, the IESO sent a notification to all interveners in Hydro One's EB-2006-0501 Transmission Rate hearing. A Stakeholder Working Group was subsequently established and administered in accordance with the IESO's Stakeholder Engagement Principles and Process. A detailed description of the Stakeholder Engagement Principles and Process can be found on the IESO's public website at the following link: http://www.ieso.ca/imoweb/consult/stakeholder_principles.asp

C) Hydro Quebec Trans-Energie did not express a view for or against mutual elimination of the export tariff between Ontario and Quebec during the course of the stakeholder consultation process. Discussions with Hydro Quebec Trans-Energie regarding reciprocal treatment of export tariff between Ontario and Quebec took place through other means. On May 26, 2009, the IESO was advised by Hydro Quebec Trans-Energie that it had no basis on which to engage in any negotiation or to participate in any reciprocal arrangements on ETS Tariff elimination. It noted that its tariff is of the cost-based type and applies uniformly to all kinds of energy flow in its jurisdiction (e.g., native load, exports, wheel-through transactions). There have been no further discussions with Hydro Quebec Trans-Energie regarding this matter since receiving this communiqué.

<u>Association of Major Power Consumers of Ontario (AMPCO) INTERROGATORY #7 List 1</u>

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

Ref: Ex A/Tab 12/Schedule 1/Page 5

HONI states that "the 2010-2012 Budget and Outlook was subsequently modified to take into account customer concerns with respect to the level of increases proposed for the 2011 and 2012 test years."

A) Please identify the specific modifications Hydro One made to the 2010-2012 Budget and Outlook to address customer concerns.

B) What criteria was used to determine the modifications identified in A) above. How were the modifications prioritized?

C) What spending was cancelled and why? What spending was deferred and why?

D) For the work that has been deferred, does Hydro One intend to complete this work in future years? If yes, what is the schedule for completion?

<u>Response</u>

A) Please refer to Exhibit 1, Tab 3, Schedule 1 and Exhibit I, Tab 1, Schedule 38.

B) Please refer to Exhibit 1, Tab 3, Schedule 1 and Exhibit I, Tab 1, Schedule 38.

C) Please refer to Exhibit 1, Tab 3, Schedule 1 and Exhibit I, Tab 1, Schedule 38.

D) The majority of reductions in Sustaining OM&A are attributed to work that was deferred and will need to be scheduled for completion in future years. It is expected that reductions attributed to changes in protection re-verifications and improved planning will be carried into the future. The specific timing of the deferred work will be determine through the annual prioritization process, and in all likelihood much of it will be done in the 2013, 2014 time frame.

The majority of the reductions in Development Capital are attributed to customer or renewable generation connections projects that were deferred 1 to 2 years from the original plan in-service date. For the non-Green projects, as long as the need exists Hydro One will continue to proceed with these projects as per the current schedule. For the Green projects, please see Exhibit I, Tab 1, Schedule 98.

Association of Major Power Consumers of Ontario (AMPCO) INTERROGATORY #8 List 1

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

Ref: Ex E1/Tab 1/Schedule 1/Page 2/Table 2

Table 2 on page 3 compares the Revenue Requirements for 2010, 2011 and 2012. Please complete the following Table to include the Board Approved Revenue Requirements for historic years.

Revenue Requirement ($ M)							
Description	**Year 2006**	**Year 2007**	**Year 2008**	**Year 2009**	**Bridge Year 2010**	**Test Year 2010**	**Test Year 2011**
OM&A							
Depreciation							
Capital Taxes							
Cost of Capital							
Total Revenue Requirement							
Less External Revenues							
Less Export Revenue Credit							
Less Other Cost Charges							
Add Low Voltage Switch Gear							
Rates Revenue Requirement							
% Change (year to year)							

Response

Revenue Requirement ($ M)							
Description	**Year 2006**[3]	**Year 2007**	**Year 2008**	**Year 2009**	**Bridge Year 2010**	**Test Year 2011**	**Test Year 2012**[1]
OM&A		394.1	387.5	415.0	426.2	436.3	450.0
Depreciation		243.6	256.1	258.0	281.3	302.9	334.8
Capital Taxes		15.7	16.4	16.4	6.0	0.0	0.0
Income Taxes [2]		64.7	52.7	24.7	34.0	80.9	70.0
Cost of Capital		438.4	457.4	464.9	509.8	625.3	692.6
Total Revenue Requirement		**1,156.4**	**1,170.1**	**1,179.0**	**1,257.3**	**1,445.5**	**1,547.4**
Less External Revenues		(24.5)	(23.6)	(18.6)	(18.0)	(31.3)	(24.7)
Less Export Revenue Credit		(12.0)	(12.0)	(12.0)	(12.0)	(10.1)	(10.2)
Less Other Cost Charges		(36.5)	(36.5)	(14.2)	(20.3)	(10.0)	2.6
Add Low Voltage Switch Gear		9.8	10.2	10.3	10.8	11.8	12.5
Rates Revenue Requirement		**1,093.2**	**1,108.3**	**1,144.5**	**1,217.7**	**1,405.8**	**1,527.5**
% Change (year to year)			1%	3%	6%	15%	9%

1. Test year 2012 has been added to the requested table under the assumption that it was inadvertently excluded from the original request.
2. The Income Taxes line item has been added to the table to show the full revenue requirement calculation under the assumption that it was inadvertently excluded from the original request.
3. There is not an approved revenue requirement for the 2006 historic year. Prior to 2007, the last approved revenue requirement was for the year 2000.

<u>Association of Major Power Consumers of Ontario (AMPCO) INTERROGATORY #9 List 1</u>

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

Ref: Ex A/Tab 12/Schedule 3/Page 7/Table 2

A) Before Table 2, (lines 4-6), it is stated that the IPSP CDM figures were adjusted for the recent recession, yet the figures for Maximum Peak Demand for the recession years (2008 and 2009) do not seem to have been changed in Table 2. Please explain.

B) Please explain the basis for calculating the difference between the IPSP Maximum peak demand incremental CDM of 787MW in 2010 versus the 387Mw used in this forecast. Please identify which programs are expected to deliver an additional 787 MW of peak demand reduction in 2010.

<u>Response</u>

A) The adjustment was for the forecast period starting 2010. The actual figures for 2008 and 2009 remained unchanged.

B) It was based on a forecast judgment of postponing 400 MW of CDM impact from 2010 to 2011 and 2012. Hydro One used the CDM assumptions provided by the OPA consistent with the 2007 IPSP submitted to the Board. For details of programs achieving 787 MW in 2010, please refer to Exhibit I, Tab 4, Schedule 11, part (d).

Association of Major Power Consumers of Ontario (AMPCO) INTERROGATORY #10 List 1

Interrogatory

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

Ref: Ex A/Tab 12/Schedule 3/Page 19/ Table 3

For 2009, the Ontario Demand forecast less CDM and Embedded Generation seems to equate to exactly 21,340 MW.

A) Is this a coincidence or were one of the forecast figures adjusted after the actual results were realized?

B) Is the 21,340 MW figure actual or weather-corrected? If weather corrected, please provide the actual number.

Response

A) 21,340 MW is the weather corrected actual for 2009.

B) See response to Part A. The actual number for 2009 is 20,798 MW.

Association of Major Power Consumers of Ontario (AMPCO) INTERROGATORY #11 List 1

Interrogatory

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

Ref: Ex A/Tab 12/Schedule 3/Pages 12-13/Figures 1 & 2

A) These figures show temperatures over a 57 year period. Please confirm that the average temperatures shown are for the entire period and not for the current 31 year period used to establish weather normal conditions.

B) Please provide and additional line on these charts showing a linear trend line of the 31 year average (e.g., starting in 1983).

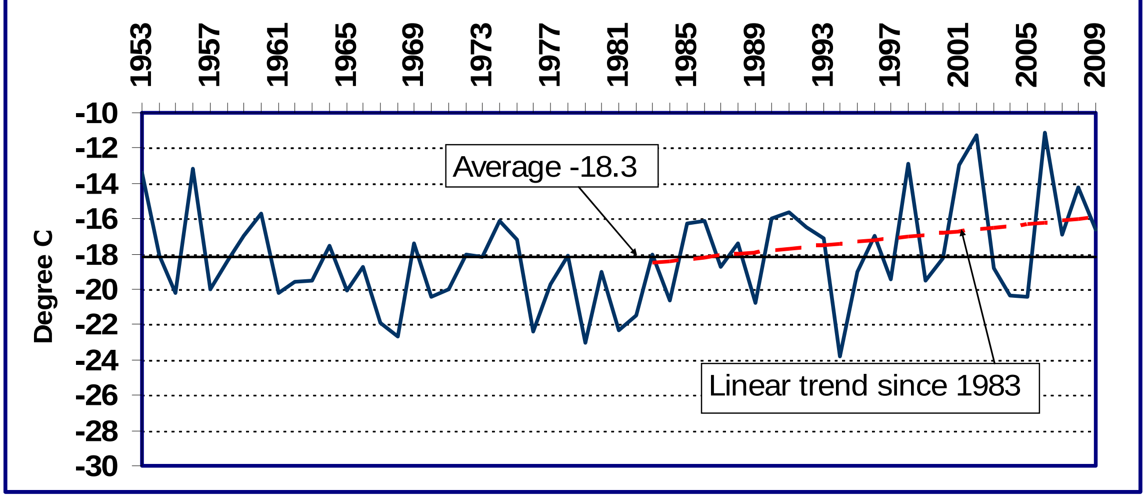
Response

A) Yes, the averages presented in Figures 1 and 2 are calculated over a 57 year period.

B) The requested linear trend lines (starting 1983) are provided below in Figures 1b and 2b.

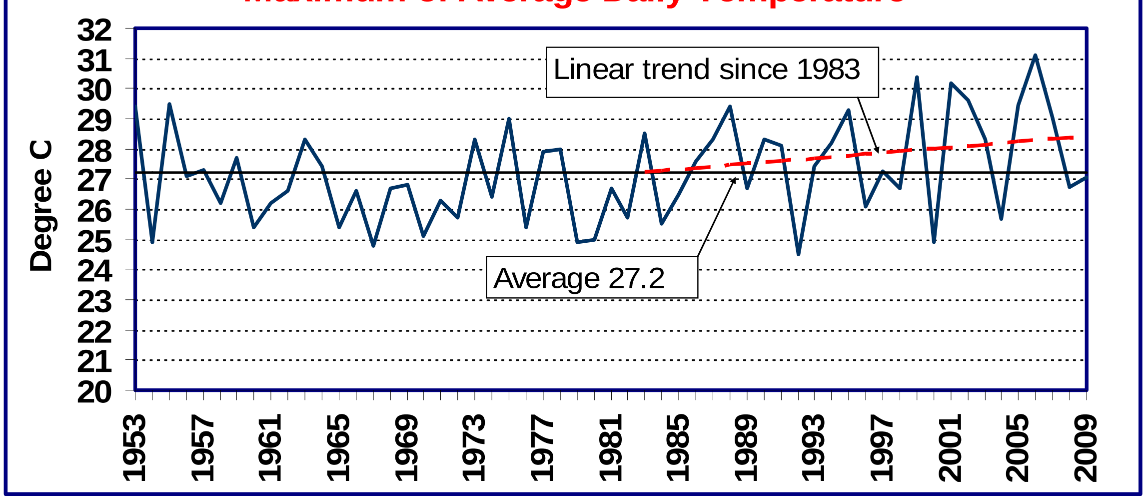
1

Figure 1b: Toronto Pearson International Airport: Minimum of Average Daily Temperature



2

Figure 2b. Toronto Pearson International Airport: Maximum of Average Daily Temperature



Association of Major Power Consumers of Ontario (AMPCO) INTERROGATORY #12 List 1

Interrogatory

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

Ref: Ex A/Tab 12/Schedule 3/Page 21/Table 5

A) For the same years as shown on this table, please provide columns showing the original (current year) forecast, the actual average monthly peak Ontario demand and the amount of weather correction applied that resulted in the calculation of forecast accuracy.

B) The note at the bottom of Table 5 seems unclear. Please provide a sample calculation for 2009 that illustrates how the calculation works to consider CDM impacts.

Response

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

Comparison of Forecast and Actual 12-Month Average Ontario Peak (MW)

	Forecast for the Current Year, 2nd Year and 3rd Year													
Year	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	Actual	Weather Correction	Weather Corrected Actual
1999	20,776											21,060	-92	20,968
2000	20,896	21,407										21,566	-197	21,369
2001	21,060	21,612	21,526									21,658	-102	21,556
2002		21,857	21,747	21,842								22,737	-928	21,810
2003			22,035	22,023	22,003							22,317	-372	21,945
2004				22,133	22,196	22,183						22,375	-211	22,164
2005					22,458	22,452	22,360					23,109	-827	22,282
2006						22,625	22,509	22,368				23,292	-772	22,520
2007							22,769	22,507	22,621			23,932	-1,512	22,420
2008								22,730	22,791	22,676		22,988	-246	22,742
2009									23,018	22,946	22,794	22,302	542	22,844

B) Please see Exhibit I, Tab 1, Schedule 30.

Association of Major Power Consumers of Ontario (AMPCO) INTERROGATORY #13 List 1

Interrogatory

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?

Ref: Ex C1/Tab2/Schedule 2/Appendix A

Please provide the most recent heath index information for the different asset components categories, as previously provided in EB-2008-0272 Ex D1/Tab 2/Schedule 1 and also in EB-2006-0501.

Response

Hydro One has not updated the previous health index information provided in EB-2008-0272 or EB-2006-0501, as the indices in themselves are not used to make specific investment decisions, except with Protection and Controls (P&C), i.e., high end electrical components. Health Indices for P&C are based primarily on trends in relay reliability from observed failure rates, rather than the condition based health indices that apply to most other asset categories. The failure rates of particular makes and models of relays are tracked through re-verification and event analysis and the current health index formulation lends itself to making investment decision on a class of assets such as with P&C, as opposed to equipment/component specific investments.

The health indices that were submitted in the previous filings referenced above would provide an overall view of the condition of asset groups. However, as noted in Exhibit D1, Tab 2, Schedule 1, page 10, a number of factors in addition to a health index are considered in determining the end of, or remaining life of an asset, as well as the need for specific investments. These are: reliability and performance, utilization, technical obsolescence, safety and environment, life cycle cost and age to some degree. Except for P&C, health indices are highly condition centric and they are indicators of an asset end of life, but there are other factors to consider as noted above. It is these other factors and the key inputs to the health indices that were used to establish the need for the sustaining investments as identified in Exhibit C1, Tab 3, Schedule 3 and D1, Tab 3, Schedule 2.

As noted above, specific investment decisions are to some degree based on the key elements of a health index. For example, conductor end of life on overhead transmission lines is based on tensile strength and ductility determine through a twist test. The results from these tests were used to establish the need for the replacement of the conductor on circuit A6P as detailed in Exhibit D2, Tab 2, Schedule 3, S38. Furthermore, Hydro One has provided evidence concerning the decision process as noted in Exhibit D1, Tab 2, Schedule 1 starting on page 12. The specific decision process for overhead conductor replacement is highlighted on page 72 of this exhibit.

Certainly, correlating asset condition to actual asset failure or remaining life, and the risk posed to system reliability and customer supply remains an industry challenge. Hydro One has begun the work to better quantify and analyse the asset risks and correlate these to the need for specific investments. To update the former health indices is a significant effort, and it is Hydro One's view that our efforts are better spent improving the analytics and developing tools that will provide greater and more specific insight into the need for investments. Furthermore, with the recent implementation of SAP and the information it provides, and the added ability to analyse asset data, substantial improvements can be made in the assessment of end of life risks.

Association of Major Power Consumers of Ontario (AMPCO) INTERROGATORY #14 List 1

Interrogatory

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?

Ref: Ex A/Tab 13/Schedule 1/Appendix B

Please augment Figures B1, B2 and B3 with linear trend lines for the periods shown.

Response

Figure B1
Historical Performance of Frequency of Delivery Point Interruptions

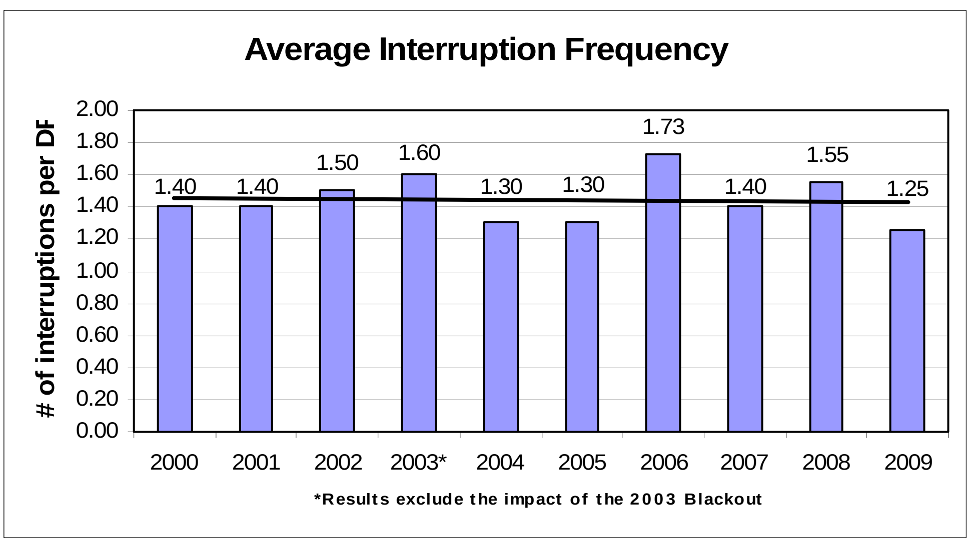


Figure B2
Historical Performance of Duration of Delivery Point Interruptions

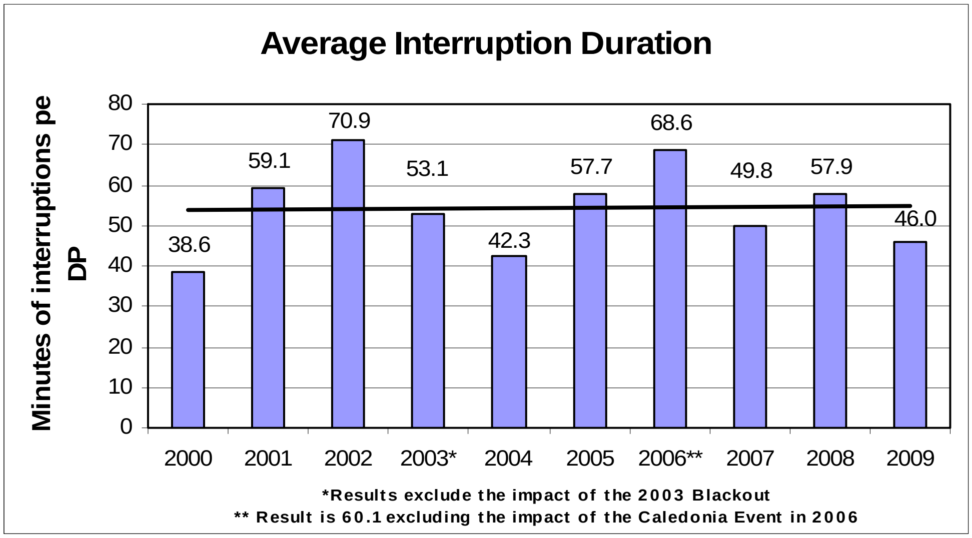
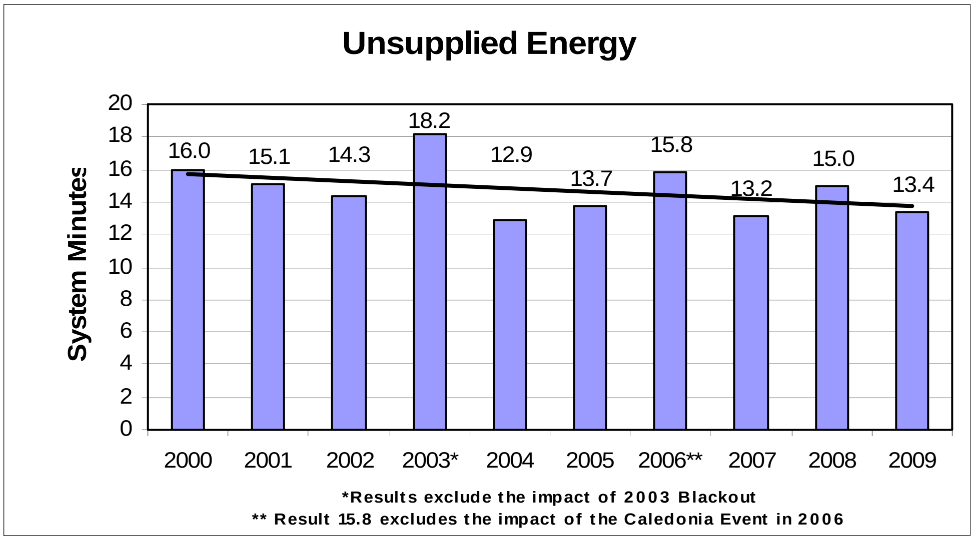


Figure B3
Historical Performance of Unsupplied Energy



Association of Major Power Consumers of Ontario (AMPCO) INTERROGATORY #15 List 1

Interrogatory

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?

Ref: Ex A/Tab 14/Schedule 1/Page 12

A) Please provide a list of the Key Performance Indicators (KPI) that is currently in use by Hydro One.

B) Please provide a list of the Key Performance Indicators (KPI) that is currently in use by Hydro One.

Response

A) The Transmission unit cost is reported each month with a variance explanation. See Exhibit I, Tab 4, Schedule 8, for year end report data.

B) The Hydro One Strategy is used to develop a Balanced Scorecard that contains a set of performance measures. At the corporate level they include:

Lost Time Injuries = (# of lost time injuries per 200,000 hours worked)

Medical Attentions = (# of medical attentions per 200,000 hours worked)

Tx Customer Satisfaction = (% satisfied)

Dx Customer Satisfaction = (% satisfied)

Smart Meters Enabled to Support Time-of-Use Billing = (# of smart meters in millions with reliable network to support TOU billing requirements)

Green Grid Enablers (Smart Zone) = (% of milestone met) (Results available quarterly)

Tx Frequency of Customer Unplanned Interruptions on 115/230kV Network System per delivery point

Tx Duration of Customer Unplanned Interruptions on 115/230kV Network System (minutes/delivery point)

Dx Duration of Customer Interruptions = (hours per customer)

Major Green Projects and Bruce to Milton Project = (% of milestone met)

Greenhouse Gas Reduction = (# of metric tonnes removed)

Employee Survey = (Grand Mean) (Results available in December)

Net Income After Tax ($M)

Credit Rating = (Long Term Debt Rating Category)

Transmission Unit Cost = (% Sustaining Capital and O&M per Asset)

Distribution Unit Cost = (Capital and O&M costs per km of line) $'000/km

Association of Major Power Consumers of Ontario (AMPCO) INTERROGATORY #16 List 1

Interrogatory

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

Ref: Ex C1/Tab 2/Schedule 9

A) Does the three year extension to the Inergi contract include requirements for continuous efficiency improvements?

B) Page 2: Has Hydro one conducted any recent reviews of the value for money it has received from the Inergi contract?

C) Page 2: Does this extension entitle Inergi to specific work in the 2013-2015 period on software projects that may not yet have been approved by the Board (e.g., replacement of legacy systems, Cornerstone 3, etc.)?

D) Page 9: it is stated that SAP maintenance costs will hold at $9M for 2010 and 2011. Is this amount contractually guaranteed with SAP or can SAP unilaterally raise this cost?

E) Page 19/Table 6: Please identify the amounts Hydro One has spent/is planning to spend on external consultants, contract staff and service providers in the IT Management and Project Control category over the years shown.

Response

A) Yes, the three year extension to the Inergi contract includes requirements for continuous efficiency improvements. These improvements are stipulated through:

- a continuous improvement obligations;

- a service level methodology that allows for continuous performance improvement and increasing of service level minimums and targets;
- a service level methodology that imposes fee credits for missed critical performance indicators;
- a base cost reduction curve over the life of the extended contract; and;
- a contract change management process that allows services to be modified to better align to changes in service requirements..

B) Yes. Hydro One engaged an outsourcing advisory firm in 2009 through to contract extension finalization in 2010, to facilitate the negotiation process and to provide advice on outsourcing market practices. In doing so, they provided advice on what services and costs Hydro One should expect in a contract extension through comparison to other outsourcing arrangements. At the conclusion of negotiations in 2010, the outsourcing advisory firm provided Hydro One with a professional judgment that the agreement, taken as a whole, is market competitive.

In addition, the original agreement between Hydro One and Inergi contained a provision for regular benchmarking. In accordance with this provision, in November 2007, Hydro One engaged an external firm to conduct a benchmarking study to provide an independent assessment of the extent to which services provided by Inergi to Hydro One were being provided at a price no greater than Fair Market Value. The overall results of the benchmark indicated that Inergi's pricing was favorable to Fair Market Value.

C) No.

D) The $9M refers to SAP application support cost which is the cost to Inergi for them to provide application support to the SAP application in accordance with the outsourced service contract. These costs do not pertain to monies provided to SAP.

The $9M in SAP application support for 2010 and 2011 is contractually guaranteed with Inergi as of the extended contract. They cannot unilaterally raise this cost without undergoing a contract change management process with Hydro One to identify and agree on any proposed changes to service, scope and/or pricing.

SAP software maintenance costs payable to SAP AG are also contractually guaranteed over the test years.

E) In the IT Management and Project Control category, Hydro One spent $2.6M in 2007, $2.9M in 2008, and $6.3M in 2009 on contract staff as well as for projects performed by external consultants and by Hydro One's outsourcer/service provider. For the years 2010, 2011, and 2012 the forecasted spend is $6.8M, $4.2M, and $3.9M respectively. Projects in this category are primarily for implementing IT security enhancements and for end-of-life server and client hardware refresh.

Association of Major Power Consumers of Ontario (AMPCO) INTERROGATORY #17 List 1

Interrogatory

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

Ref: Ex C1/Tab 2/Schedule 1/Page 2/Table 1

Table 1 provides a summary of Hydro One's Transmission's actual OM&A expenditures for the historical, bridge and test years. Please complete the following table to compare historical OM&A costs to the Board Approved amounts.

OM&A Costs ($M)													
Description	2006 BA	2006 Actual	2006 Var	2007 BA	2007 Actual	2007 Var	2008 BA	2008 Actual	2008 Var	2009 Actual	2009 BA	2010 Bridge	2011 Test	2012 Test
Sustaining														
Development														
Operations														
Shared Services & Other OM&A														
Customer Care														
Property Taxes & Rights Payments														
SUB-TOTAL														
Dev Work for Tx Projects (Gov Instruction)														
TOTAL														

Notes: BA = Board Approved; Var = Variance

B) Please provide an explanation of the variances for 2006 to 2008.

Response

A) See table below comparing historical OM&A costs to the Board Approved amounts:

OM&A Costs ($M)														
Description	**2006 BA**	**2006 Actual**	**2006 Var**	**2007 BA**	**2007 Actual**	**2007 Var**	**2008 BA**	**2008 Actual**	**2008 Var**	**2009 Actual**	**2009 BA**	**2010 Bridge**	**2011 Test**	**2012 Test**
Sustaining		179.0		200.1	205.9	5.8	200.9	187.5	(13.40)	213.5	211.6	224.4	233.0	243.1
Development		8.1		8.0	8.4	0.4	8.1	9.2	1.10	14.0	13.9	19.0	18.2	18.9
Operations		42.9		49.9	54.0	4.1	49.7	51.7	2.00	52.6	57.3	62.1	66.3	68.2
Shared Services & Other OM&A		76.3		61.9	80.9	19.0	52.2	59.4	7.20	70.8	61.1	58.6	46.9	46.4
Customer Care		0.0		1.6	1.2	(0.4)	1.6	1.3	(0.30)	0.9	1.5	1.1	1.1	1.2
Property Taxes & Rights Payments		68.6		72.8	62.5	(10.3)	75.1	64.8	(10.30)	65.2	69.7	69.4	70.8	72.2
Total OM&A		374.9		394.1	412.9	18.7	387.5	373.8	(13.70)	417.1	415.0	434.5	436.3	450.0
Dev Work for Tx Projects (Gov Instruction) Deferral Account										1.9	0.0	8.2	35.7	46.7
TOTAL with Deferral Acct. OM&A		374.9		394.1	412.9	18.7	387.5	373.8	(13.70)	419.0	415.0	442.7	472.0	496.7

* No Board Approved amounts for 2006

B) There were no Board approved numbers to compare for 2006. The explanation of variances for 2007 and 2008 actual OM&A costs compared to the OM&A expenditures approved by the Board are summarized below.

<u>2007 Variances</u>

Hydro One Transmission's actual 2007 OM&A costs were $19 million higher than the $394 million approved by the Board in Proceeding EB-2006-0501. This was due to a lower capitalized overhead credit of $16 million and higher spending in response to storms and other unforeseen asset needs. The increase in OM&A costs were offset by a $10 million decrease in Property Taxes and Rights Payments.

<u>2008 Variances</u>

Hydro One Transmission's actual 2008 OM&A costs were $13.7 million lower than the $388 million approved by the Board in Proceeding EB-2006-0501. This difference was primarily related to decreases in stations sustainment costs and Property Taxes and Rights Payments offset by an increase in Shared Services related to an increase in cost of sales.

Association of Major Power Consumers of Ontario (AMPCO) INTERROGATORY #18 List 1

Interrogatory

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?

Ref: Ex C1/Tab 2/Schedule 7/Page 10

A) Please provide a table of the number of employees that have been eligible for undiscounted retirement for the past 5 years (up to and including 2009) and the number of employees that have taken undiscounted retirement.

B) Please provide a table of the median age of employees eligible for undiscounted retirement for the past 5 years (up to and including 2009) and the median age of employees that have taken undiscounted retirement.

Response

A) and B)

Year	Number of Employees Eligible for Undiscounted Pension	Cumulative Number of Employees Eligible for Undiscounted Pension	Median Age of Employees Eligible for Undiscounted Pension	Number of Employees who took an Undiscounted Pension	Median Age of Employees who took an Undiscounted Pension
2005	409*	409	57.03	60	54.87
2006	155	564	54.76	61	55.97
2007	133	697	53.98	69	54.74
2008	189	886	53.02	103	55.89
2009	162	1048	53.77	111	56.05

*In 2005, Number of Employees Eligible for Undiscounted Pension includes all employees from previous years who did not elect to retire. Employees who took Undiscounted Pension in a given year may have been eligible in previous years, but did not elect to retire in that year.

Association of Major Power Consumers of Ontario (AMPCO) INTERROGATORY #19 List 1

Interrogatory

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?

Ref: Ex D1/Tab 3/Schedule 2/ Page 19
Ref: Ex D2/Tab 2/Schedule 3/ISD # S 16

Please provide a table listing the operating spares that have been placed into active service (i.e., activated as replacements for failed transformers or for transformers requiring refurbishment) annually for the period 2005-2009, along with the current spares inventory, by primary voltage and MVA Rating .

Response

Table 1 lists the operating spares that were placed into active service.

Table 2 lists the operating spares currently on-hand by primary voltage and MVA rating.

Table 1
Transmission Operating Spares Placed into Active Service

Year Installed	Name	Functional Location	Capacity (MVA)	Primary Voltage (kV)
2005	Woodbridge TS	N-TS-WOODBRDGTS-TF-SS4	0.2	44
	Trafalgar TS	N-TS-TRAFALGRTS-TF-T15	750	500
	Hinchinbrooke SS	N-TS-HINCHNBKSS-TF-SS2	0.6	14
	Cooksville TS	N-TS-COOKSVILTS-TF-T6	83.3	230
	St.Andrews TS	N-TS-STANDREWTS-TF-GT3	200A/ph.	28
2006	Birmingham TS	N-TS-BIRMNGHMTS-TF-T4	75	115
	Wiltshire TS	N-TS-WILTSHIRTS-TF-T1	42	115
	Goderich TS	N-TS-GODERICHTS-TF-T1	25	115
	Essa TS	N-TS-ESSATS -TF-TSS21	0.3	13.8
	Manby TS	N-TS-MANBYTS -TF-T6	42	230
	Nelson TS	N-TS-NELSONTS -TF-T4	75	115
	Cherrywood TS	N-TS-CHERRYWDTS-TF-T14	750	500
	Carlton TS	N-TS-CARLTONTS -TF-T3	75	115
2007	Cecil TS	N-TS-CECILTS -TF-T2	100	115
	Bramalea TS	N-TS-BRAMALEATS-TF-T1	125	230
	Pinard TS	N-TS-PINARDTS -TF-T1	750	500
	Glengrove TS	N-TS-GLENGROVTS-TF-T3	42	115
	Martindale TS	N-TS-MARTINDLTS-TF-T61	33.5	115
	Thornton TS	N-TS-THORNTONTS-TF-SS1	0.2	44
	Claireville TS	N-TS-CLAIREVLTS-TF-SS3	1	28
2008	Alliston TS	N-TS-ALLISTONTS-TF-T3	83.3	230
	Keith TS	N-TS-KEITHTS -TF-T23	83.3	230
	Alliston TS	N-TS-ALLISTONTS-TF-T4	83.3	230
	Cherrywood TS	N-TS-CHERRYWDTS-TF-T16	750	500
2009	Elliot Lake TS	N-TS-ELLIOTLKTS-TF-T3	42	115
	Porcupine TS	N-TS-PORCUPINTS-TF-T8	360	500

Table 2
Existing Transformer Operating Spare Inventory

Primary Voltage	MVA	# Of Operating Spares On-Hand
500 kV	750	2
500 kV	250	1
230 kV	250	2
230 kV	125	5
230 kV	83	6
230 kV	42	1
115 kV	100	0
115 kV	83	4
115 kV	75	4
115 kV	42	9
115 kV	25	4

<u>Association of Major Power Consumers of Ontario (AMPCO) INTERROGATORY #20 List 1</u>

<u>Interrogatory</u>

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?

Ref: Ex D2/Tab 2/Schedule 2

For those projects and programs over $3M that were also present in this schedule in the EB-2008-0272 application, please provide a revised version of this schedule with three columns added, indicating the amounts requested for 2009, spent in 2009 and projected for 2010.

<u>Response</u>

The amounts requested are provided in the table below.

LIST OF CAPITAL INVESTMENT PROGRAMS OR PROJECTS REQUIRING IN EXCESS OF $3 MILLION

1.0 Sustaining Capital (Exhibit D1, Tab 3, Schedule 2)

1.1 Stations

		2009 Requested	**2009** Spent	**2010** Projected	**2011**	**2012**
S1	2011/2012 Oil Circuit Breaker Replacement Program	3.8	5.2	7.6	6.9	7.9
S3	2011/2012 Metalclad Circuit Breakers Replacement – GTA	3.6	9.1	5.2	10.5	10.7
S4	Beck #1 SS: Air Blast Circuit Breaker (ABCB) Re-Investment	3.5	0.1	0.27	25.5	20.6

1.1 Stations

		2009 Requested	**2009** Spent	**2010** Projected	**2011**	**2012**
S5	Abitibi Canyon Switching Station (SS) and Pinard Transformer Station (TS) - Replace EOL Components	2.1	0.2	0.2	10.3	10.3
S6	Nanticoke TS: Air Blast Circuit Breaker (ABCB) Re-Investment	9.5	11.1	3.65	4.3	0
S7	Orangeville TS: Air Blast Circuit Breaker (ABCB) Re-Investment	7.1	0.0	0.06	10.3	10.6
S13	Richview TS - Replace EOL Transformers T7/T8	0.7	0.02	4.17	6.4	2.8
S15	Leaside TS - Replace EOL Transformers T19, T20 and T21	7.5	1.83	11.1	4.9	6.5
S16	Purchase Spare Transformers	8.8	14.0	25.0	13.2	13.3
S19	2011/2012 Station Service Upgrades	7.3	3.92	4.04	11.6	11.8
S20	2011/2012 Spill Containment Refurbishment – Major	2.8	2.95	2.8	8.4	8.5
S24	2011 - 2012 Station P&C Replacement	8.0	16.7	29.0	22	22.2
S26	2011-2012 RTU Replacement	2.2	10.2	9.25	5	5.5
S31	TDCN Cyber Security	0.0	0	0	5.3	5.1

1.2 Lines

		2009 Requested	2009 Spent	2010 Projected	2011	2012
S34	2011/2012 Transmission Wood Pole Replacement Program	27.3	21.5	35.8	30.8	31.3
S35	2011/2012 Steel Structure Coating Program	3.0	2.5	2.1	5.5	6.5
S36	2011/2012 Shieldwire Replacement Program	4.1	2.4	3.8	4.2	4.3
S37	2011/2012 Transmission Lines Emergency Restoration	6.0	15.7	6.5	6.6	6.6

2.0 Development Capital (Exhibit D1, Tab 3, Schedule 3)

2.1 Inter-Area Network Transfer Capability

		2009 Requested	2009 Spent	2010 Projected	2011	2012
D1	New 500 kV Bruce to Milton Double Circuit Transmission Line	170.3	150.1	191	184.4	94.3
D2	Northeast Transmission Reinforcement: Install SVC's at Porcupine TS & Kirkland Lake TS	48.5	29.3	57	33.1	0
D3	Nanticoke TS - Install 500 kV, 350 MVar Static Var Compensator	15.2	2.8	59.6	22.1	0
D4	Detweiler TS - Install 230 kV, 350 MVar Static Var Compensator	13.1	1.2	44	34.9	0
D6	Porcupine TS - Install two100 MVar Shunt Capacitor Banks	0	0.1	1.1	10.3	0.2

2.2 Local Area Supply Adequacy

		2009 Requested	2009 Spent	2010 Projected	2011	2012
D9	Woodstock Area Transmission Reinforcement	32.3	20.8	24.7	20.7	0
D10	Rebuild Burlington TS 115kV Switchyard	5.5	2.4	19.8	30.4	1.4
D14	Midtown Transmission Reinforcement Plan	0	0.9	3.8	31	36.7

2.3 Load Customer Connection

		2009 Requested	2009 Spent	2010 Projected	2011	2012
D16	Commerce Way TS: Build new TS and Line Connection (formerly Woodstock East TS)	0.2	1.0	10.9	27.1	6.5
D22	New 230/28 kV Transformer Station in Northern Mississauga & Line Connection	2.0	0	0	0.1	7.4
D23	Enfield TS: Build 230/44 kV DESN and Line Connection (formally Oshawa Area TS)	0.4	0.1	0	0.0	4.9
D24	Long Lac TS: Replace End-of-Life 115-44 kV Transformers	1.0	5.5	8.5	5.3	0.0
D27	Duart TS: Build new Transformer Station and Line Connection (formerly Rodney TS)	3.0	0.9	0.7	12.1	12.6

2.4 Generation Customer Connection

		2009 Requested	2009 Spent	2010 Projected	2011	2012
D31	Lower Mattagami Generation Connections	6.9	0.1	0.5	2	4

3.0 Operations Capital (Exhibit D1, tab 3, schedule 4)

3.1 Operating Infrastructure

		2009 Requested	2009 Spent	2010 Projected	2011	2012
O6	Wide Area Network	0	0.1	0.3	11	26.1

4.0 Shared SERVICES and other capital (Exhibit D1, Tab 3, schedule 5)

4.1 Information Technology

		2009 Requested	2009 Spent	2010 Projected	2011	2012
IT1	Cornerstone Phase 2	82.1	91	14.9	-	-
IT2	Cornerstone Phase 3	18.2	0	20	20.8	29.3
IT3	Mobile IT Platform	3	1	2.5	3	2

4.2 Other

		2009 Requested	2009 Spent	2010 Projected	2011	2012
C1	Real Estate Facilities Capital for 2011 and 2012	30.7[1]	16.8	27.4	25.8	19.6
C2	Real Estate Head Office and GTA Facilities Capital for 2011 and 2012		0.3	21	19	15.6
C3	Shared Services Capital – Service Equipment	11.6	6.6	12	8.8	5.9
C4	Shared Services Capital – Transport & Work Equipment	39.7	46.5	61	74.1	60.2

[1] As presented in EB-2008-0272.

Association of Major Power Consumers of Ontario (AMPCO) INTERROGATORY #21 List 1

Interrogatory

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?

Ref: Ex D2/Tab 2/Schedule 3

A) Project S3 appears to be virtually identical to project S2 in EB-2008-0272, the replacement of 4 EOL metalclad circuit breakers in the GTA, along with protections and 15kV cables. At the same tie, the proposed budget of $23.5M appears to be almost triple the $8.0M budgeted for the same work description and the same level of accomplishment in EB-2008-0272. Please explain this large variance.

B) Project S4 appears to be the same project S4 described in EB-2008-0272. Please explain the project extension and budget increase.

C) Project S7 (Orangeville TS ABCB Re-investment):

i) Is this project identical to project S5 in EB-2008-0272, or is it for an additional set of breakers?

ii) If this is a continuance of the previous S5, is the station service being replaced twice?

iii) If this is the same project, please explain the delay in completion and the cost increase of $5.3M.

iv) If this is a continuing program, please explain the significantly increased unit cost versus the previous S5.

D) Project S6 appears to be the completion of project S7 from EB-2008-0272, budgeted then at $35.0M. If this is correct, please identify what the total budget was for this project and the variance, if any.

E) Project S15 appears to be for the same replacement work identified in Project S12 in EB-2008-0272 and scheduled for completion in 2009. If this is accurate, please provide an explanation of the variance and in-service delay.

F) Project S13 appears to be identical to Project S15 in EB-2008-0272, originally scheduled for completion in 2010 at a gross cost of $9.5M. If this is accurate, please explain the cost escalation and the delay.

G) Project S20 (spill containment refurbishment): Please identify 2009 and 2010 costs and accomplishments (systems refurbished) for this program.

H) Project D2 (Kirkland Lake & Porcupine SVCs): Please explain the schedule extension and variance for this project.

I) Project D35 (Northwest Transmission Reinforcement):

i) Please identify the current load in the Pickle Lake area that is served by Hydro One and which this reinforcement will also serve.

ii) Please identify how Hydro One plans to recover cost of this reinforcement from new customers, both load and renewable generators.

iii) Please provide a breakout of the cost of the line, separating the cost to reach LJF and the wind generation on the East Side of Lake Nipigon from the extension to Pickle Lake loads.

iv) Please provide the expected capacity of the portion of the line from Lake Nipigon to Pickle Lake.

Response

A) When EB-2008-0272 was prepared and filed, Hydro One had not yet completed any metalclad circuit breaker replacement projects with THESL. Since that time, Hydro One has performed four separate metalclad replacement projects. Planned expenditures in the test years are for projects very similar to those completed in 2009 and 2010, and pricing has been updated accordingly.

B) The project in-service date has been extended due to the expansion of the scope of work, and as a result the planned costs have increased to meet the requirements of external stakeholders. Specifically, negotiations were required between Hydro One, OPG, IESO, and Parks Canada around issues such as the configuration of the new switchyard, the demerger of assets from the OPG powerhouse, available land for the construction of a new switchyard, interconnections to National Grid's system, and decommissioning of the 25Hz equipment. The project delays are attributed to the additional time required to incorporate the requirements of these stakeholders and negotiate property rights.

C)
   i) S7 from EB-2010-0002 and S5 from EB-2008-0272 are the same project to replace end of life air-blast breakers at Orangeville TS. To gain efficiencies and minimize the required system outage time, Hydro One modified the project scope to account for both the Sustaining need to replace EOL assets and the Development need to reconfigure the existing bus configuration by adding a third 230kV diameter to improve system flexibility and reliability by terminating all incoming circuits into breaker and half configuration.
   ii) No.
   iii) The project was delayed from the original in-service date by Hydro One for two reasons:
      - Allow time for the more complex project scoping and planning necessary to meet the Sustaining and Development program requirements
      - Allow resources and funding to be utilized for the completion of other high priority work, specifically P&C capital work associated with EOL asset replacements and the NERC cyber security regulations

      The resulting cost increase from the previous filing is attributed to the larger scope of the project as discussed above, specifically the inclusion of the three new breakers, line re-terminations, and EOL instrument transformers.
   iv) See part iii).

D) S6 from EB-2010-0002 is the same project as S7 from EB-2008-0272 for the Nanticoke 230kV ABCB replacements. The in-service date remains unchanged from previous filing as mid-2011. The total project capital cost remains the same as identified in the previous filing at $31.0M.

E) S15 from EB-2010-0002 is the same project as S12 from EB-2008-0272 for the replacement of Leaside T19, T20, and T21 transformers. The in-service date for the complete project has changed from late 2009 to early 2012 as a result of the following:

- The detailed project engineering phase revealed necessary expansions of the project scope, which also resulted in cost increases. This additional work includes modifications to the existing rigid bus work on both the high & low side of the transformers, and changing the LV bus work to a higher ampacity, allowing the transformer's overload capabilities to be fully utilized.
- The procurement of the transformers took longer than expected, in part due to manufacturing and factory testing delays

The completion of the T21 portion of the project is expected in early 2011 and the remaining two transformers will be completed by early 2012.

F) S13 from EB-2010-0002 is the same project as S15 in EB-2008-0272 for the replacement of Richview T7 and T8 transformers. The detailed engineering phase of the project revealed necessary expansion of the project scope, which resulted in capital cost changing from $8.6M to $9.2M. The expanded scope includes additional work to replace insulators within the transformer zone and install surge arresters in place of the existing rod-gaps. The in-service date has changed to 2012 from late 2010.

G) 2009 actual capital costs were $3.0M for work completed on 11 systems, and 2010 bridge year projected capital costs are $2.8M for work on 6 systems.

H) At the time of rate filing, the Kirkland Lake SVC in-service date was delayed, at the supplier's request. Major factors include: (1) delays in identifying the supplier's civil sub-contractor, (2) the discovery of "contaminated" excavated material at Site, and (3) delays in the submission of the Certificate of Approval oil containment/drainage engineering package to the Ministry of the Environment (Ontario).

This I/S date delay was expected to result in a potential cost increase and additional contingency was added to the project accordingly.

I)

i) The current load at Pickle Lake is approximately 23 MW
ii) If sufficient information and direction is provided Hydro One will continue to evaluate a number of alternatives to recover the cost of this project from interested stakeholders.
iii) The estimated construction cost of the line from Nipigon to Pickle Lake is $399.5M as presented in evidence. A breakout of the construction cost for the section from Nipigon to LJF (Auden) and the section from LJF (Auden) to Pickle Lake has not been done.
iv) The thermal capacity of the line would be 400 MVA.

Association of Major Power Consumers of Ontario (AMPCO) INTERROGATORY #22 List 1

Interrogatory

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?

Ref: Ex D1/Tab 3/Schedule 1/Page 2/Table 1

Table 1 on page 2 provides a summary of Hydro One's Transmission's actual capital expenditures for the historical, bridge and test years. Please complete the following Table to compare historical capital costs to the Board Approved capital amounts.

Capital Costs ($ M)														
Description	**2006 BA**	**2006 Actual**	**2006 Var**	**2007 BA**	**2007 Actual**	**2007 Var**	**2008 BA**	**2008 Actual**	**2008 Var**	**2009 Actual**	**2009 BA**	**2010 Bridge**	**2011 Test**	**2012 Test**
Sustaining														
Development														
Operations														
Shared Services Capital														
TOTAL														

BA – Board Approved; Var = Variance

B) Please provide an explanation of the variances for 2006 to 2008.

Response

A)

Capital Costs ($ in Million)														
Description	**2006 BA***	**2006 Actual**	**2006 Var***	**2007 BA**	**2007 Actual**	**2007 Var**	**2008 BA**	**2008 Actual**	**2008 Var**	**2009 Actual**	**2009 BA**	**2010 Bridge**	**2011 Test**	**2012 Test**
Sustaining	N/A	178.5	N/A	288.1	210	(78.1)	295.6	280.4	(15.2)	300.0	279.9	308.3	424.0	443.4
Development	N/A	179.4	N/A	318.8	272.6	(46.2)	415.6	310.9	(104.7)	516.2	545.9	537.9	617.2	456.8
Operations	N/A	9.4	N/A	20.1	4.7	(15.4)	20.4	23.1	2.7	20.0	18.2	10.1	44.3	57.4
Shared Services Capital	N/A	34.1	N/A	84.6	72.2	(12.5)	42.8	89.8	47.0	81.5	92.4	73.6	66.3	50.6
TOTAL	N/A	401.6	N/A	711.6	559.5	(152.1)	774.4	704.2	(70.2)	917.8	936.5	930.0	1151.8	1008.3

* No Board Approved amounts for 2006.

B) There were no Board approved numbers to compare for 2006. The explanation of variances for 2007 and 2008 actual Capital costs compared to the Capital expenditures approved by the Board are summarized below.

2007 Variances

Hydro One Transmission's capital expenditures in 2007 were $152 million below the total projected expenditures approved by the Board.

The reasons for the lower spending on Sustaining, Development and Operations capital programs in 2007 were attributed to the following:

- Redirection of resources as a result of a number of large unplanned events in 2007. The unplanned events included a building fire at Pickering TS, a transformer failure and fire at Pinard TS and capacitor bank transient voltage faults at Richview TS.
- Redirection of resources from Sustaining in 2007 to complete demand-driven Development work (e.g. new generator connections and new load connections) and other externally mandated work.
- Delays in completing the necessary engineering work as a result of difficulty in recruiting the required specialist engineering staff. This difficulty arose from competing demands from other organizations in Ontario, Alberta, and from international organizations recruiting to satisfy major global expansions in India, China and other rapidly expanding locations.
- Delays due to difficulty in getting the required outage approvals from the IESO as a result of transmission system limitations.
- Longer lead times to obtain key materials and equipment.

The primary reason Shared Services was under spent in 2007 was related to a delay in spending on the Cornerstone project from 2007 to 2008.

2008 Variances

Hydro One Transmission's capital expenditures in 2008 were $70.2 million below the expenditure levels approved by the Board in EB-2006-0501. The lower spending on Development programs in 2008 was due to the same constraints as in 2007, in particular labour and material resource availability and the ability to get the outages required to do the work.

The constraints identified above were being managed by balancing short and long term risks in the re-assignment of priority work. Priority work included generator and load connection projects, major development projects at key stations, system interconnections, emergency repair work, work that was compliance driven and planned sustainment work programs. Although the re-prioritization of work had resulted in some reductions to Sustaining work programs, actions were being taken to increase work execution capacity and assisted in ensuring Hydro One Transmission can complete the full complement of work programs proposed for 2009 and 2010.

The higher than plan spending in 2008 on Shared Services was largely due to a shift in spending on Cornerstone.

Association of Major Power Consumers of Ontario (AMPCO) INTERROGATORY #23 List 1

Interrogatory

8.1 Is it appropriate to implement "AMPCO's High 5 Proposal" in place of the status quo charge determinants for Network service?

Ref: Ex H1/Tab 3/Schedule 1/Attachment 1/Page 1/Section 1

The Introduction section of the Power Advisory Report includes the Board's directive. In its Decision With Reasons (EB-2008-0272), the OEB directed Hydro One to come forward at its next application with:

1. further analysis of AMPCO's proposal; and
2. a suitable proposal for implementation for the OEB's consideration in the event the OEB decides to change the charge determinant.

A) Please explain why the second item was excluded from the scope of the Consultant's report.

B) Please indicate when the applicant intends to file material fulfilling this aspect of the Board's direction in EB-2008-0272.

Response

A) The second item was excluded from the scope of the consultant's report because Hydro One, in consultation with the IESO, has the information needed to respond to this aspect of the directive and the consultant's assistance was not required on this item.

B) Hydro One has filed information with respect to the implementation of the AMPCO proposal in the event that the Board decides to change the charge determinants. The evidence can be found in the update to Exhibit H1, Tab 3, Schedule 1, pages 4 to 6 filed July 6, 2010.

Association of Major Power Consumers of Ontario (AMPCO) INTERROGATORY #24 List 1

Interrogatory

8.1 Is it appropriate to implement "AMPCO's High 5 Proposal" in place of the status quo charge determinants for Network service?

Ref: Ex H1/Tab 3/Schedule 1/Page 1/Section 1.1, sub (1) "comprehensive impact analysis"

HONI requested that the Consultant provide a comprehensive impact analysis of the likely and potential effects, costs and benefits of implementing AMPCO's proposal.

A) Please provide estimates of the costs of implementing AMPCO's proposal, if any costs have been identified and such estimates have been made. If costs have not been estimated, please explain why such estimates were determined not to be within the scope of the required analysis of AMPCO's proposal.

B) Please provide estimates of the benefits of implementing AMPCO's proposal, if benefits have been identified and such estimates have been made. If benefits have not been estimated, please explain why such benefits were determined not to be within the scope of the required analysis of AMPCO's proposal.

C) Please explain, in the Consultant's opinion, the extent to which the AMPCO proposal is more or less likely, compared to the status quo scheme for network charge determinants, to promote efficiency in transmission or to promote efficient demand management.

D) Please provide an analysis, if any has been done, of the "localized transmission system impacts" of implementing AMPCO's proposal.

Response

The response to parts B, C and D are provided by Power Advisory.

A) Please refer to Exhibit I, Tab 4, Schedule 63, part c.

B) Power Advisory estimated that implementing AMPCO's proposal would provide the following benefit: (1) reduced power supply costs from reductions in load during peak periods. This benefit was estimated to be about $2.44 million in 2011 under the High Load Shift Case, $1.71 million under the Central Load Shift Case, and $980 thousand under the Low Load Shift Case. In addition, the High 5 proposal could defer network transmission system investments and reduce network transmission revenue requirements. However, Power Advisory didn't identify any network transmission investments that would be deferred and found that given the concentration of direct industrial customers, load reductions of sufficient magnitude to defer transmission investments are only likely to occur in areas where such investments are not needed.

C) As discussed, in our Report we don't believe that the High 5 Proposal would necessarily promote efficiency in transmission since in Ontario under the Green Energy Act transmission investment isn't necessarily promoted by increases in system peaks. However, over the longer term the load shifting promoted by the High 5 Proposal could promote greater efficiency in transmission. While the High 5 proposal would promote additional demand management, it isn't clear that the load reductions from this additional demand management are economically efficient, i.e., cost-justified. Therefore, it isn't clear that the High 5 proposal would promote more efficient demand management compared to the status quo.

D) Power Advisory evaluated the "localized transmission system impacts" of implementing AMPCO's proposal in Chapter 6 of its report. To assess the potential of AMPCO's High 5 Proposal to defer local transmission system investments we identified the conditions that are required to defer transmission investments, i.e., load reductions must be greater than forecast load growth. We then contrasted the likely levels of load shift in different transmission zones in Ontario with the likely level of load growth. This analysis indicated that "the only zones where the load shift is likely to be greater than the annual load growth are the Northeast and Northwest. The Northeast and Northwest zones offer the greatest potential load shift given the concentration of industrial load in these zones. However as discussed, actual forecast load growth in the Northeast and Northwest is negative and as a result there is unlikely to be any significant transmission investments in this area that are specifically attributable to incremental load growth other than new project-driven load growth which requires transmission investment to connect them into the IESO-controlled grid. Furthermore, these zonal loads are spread over large areas and as a result the resulting load reductions may not be sufficiently concentrated in the area where the transmission facility investment is required to defer the local area investment." (Power Advisory, Assessment of AMPCO's High 5 Proposal for Establishing Network Charge Determinants, p. 72). Furthermore, we discussed with Hydro One Transmission's system planners the load reductions that we expected the High 5 Proposal to produce. They indicated that load reductions of this magnitude would have no ability to defer any major transmission investments given that the load reductions would be spread across the Province roughly in proportion to the concentration of industrial load in different zones.

<u>Association of Major Power Consumers of Ontario (AMPCO) INTERROGATORY #25</u>
<u>List 1</u>

Interrogatory

8.1 Is it appropriate to implement "AMPCO's High 5 Proposal" in place of the status quo charge determinants for Network service?

Ref: Ex H1/Tab 3/Schedule 1/Attachment 1

Please provide the Consultant's analysis, including assumptions, input data sets, calculations and results with respect to the effect of the AMPCO proposal on the economic efficiency of the Ontario electricity market in total, relative to the status quo.

Response

This response is provided by Power advisory.

Power Advisory did not perform any quantitative analysis of the effect of the AMPCO proposal on the Ontario electricity market in total, relative to the *status quo*. However, we did identify commodity cost reductions from projected load shifts that indicate that the High 5 proposal could result in reductions in electricity supply costs to consumers. Lost profits to suppliers would need to be netted from these electricity supply cost reductions to estimate the economic efficiency gains.

Association of Major Power Consumers of Ontario (AMPCO) INTERROGATORY #26 List 1

Interrogatory

8.1 Is it appropriate to implement "AMPCO's High 5 Proposal" in place of the status quo charge determinants for Network service?

Ref: Ex H1/Tab 3/Schedule 1/Attachment 1/Page vi-vii

A) On table ES-3, the estimated load shifting is shown as 86 MW. Please identify the economic value to Ontario ratepayers that the Consultant has attributed to the avoidance of additional peaking generation, and include relevant assumptions, input data sets, and calculations.

B) The Consultant estimates that the average bill impact for a LDC residential customer would be $2.40 per year. Please provide analysis in support of this estimate, including assumptions, input data sets and calculations.

C) Did the Consultant consider and quantify the extent to which rate increase for LDC customers could be implemented by way of changes to Time of Use rates so as to enhance load shifting? If so, Please provide the relevant analysis, including assumptions, input data sets, calculations and results.

Response

The response to parts A, B, and C are provided by Power advisory.

A) Power Advisory didn't estimate the economic value to Ontario ratepayers of avoiding additional peaking generation. However, Power Advisory analyses suggest that Ontario doesn't have a need for additional generation resources for capacity purposes until 2018 so there would not likely be benefits from avoiding additional peaking generation prior to this.

The average monthly bill of $120 is based on an examination of data presented on the OEB web site at:

http://www.oeb.gov.on.ca/OEB/Consumers/Electricity/Your+Electricity+Utility/All+Electricity+Utility+Bills

B) Subsequent calculations are based on percentage components of the bill provided by Hydro One and the step-by-step calculation based on these inputs described on page 55 of the Power Advisory report. Thus:

- Transmission charges are approximately 7.5 % of the total bill or $9/month
- Network charges are approximately 60% of transmission charges or $5.40/month
- Network charges increase by 3.7% as shown on Table 15 ($28.5 million increase on a base of $763.6 million)
- A 3.7% increase applied to $5.40 per month of network charges is $0.20 per month or $2.40 per year.

C) Power Advisory calculated average cost increases without regard to any specific rate design approach.

Association of Major Power Consumers of Ontario (AMPCO) INTERROGATORY #27 List 1

Interrogatory

8.1 Is it appropriate to implement "AMPCO's High 5 Proposal" in place of the status quo charge determinants for Network service?

Ref: Ex H1/Tab 3/Schedule 1/Attachment 1/Page 10/Section 2.1/Footnote 22

A) The Consultant suggests that the AMPCO proposal may result in a "reduction in market revenues to generators." Please provide analysis in support of the potential aggregate impact on generators (net of revenue changes and transmission cost changes) of implementing the AMPCO proposal, including assumptions, input data sets, calculations and results.

B) It is unclear whether the Consultant predicts that the net effect of the AMPCO proposal on the amount of Global Adjustment is likely to be positive or negative. Please clarify and provide supporting analysis, including assumptions, input data sets, calculations and results.

Response

The response to parts A and B are provided by Power advisory.

A) Power Advisory didn't estimate the magnitude of the reduction in market revenues to generators. However, the benefit to consumers of lower wholesale market prices is offset to a degree by a cost to generators in the form of reduced market revenues. In Ontario, a high proportion of electricity generation is under contract and the Global Adjustment Mechanism is used to compensate generators when market prices are below contract revenues. This mechanism reduces the revenue loss to generators but, since consumers ultimately pay the Global Adjustment, this mechanism also reduces the benefit to consumers from the lower prices.

B) Power Advisory expects that the increases in the Global Adjustment would offset a significant proportion of the commodity cost savings realized by consumers. Specifically, while implementation of the High 5 proposal may cause HOEP to decrease, Power Advisory believes that a significant portion of this decrease would be offset by increases in the Global Adjustment.

Association of Major Power Consumers of Ontario (AMPCO) INTERROGATORY #28 List 1

Interrogatory

8.1 Is it appropriate to implement "AMPCO's High 5 Proposal" in place of the status quo charge determinants for Network service?

Ref: Ex H1/Tab 3/Schedule 1/Attachment 1/Page 16/Section 2.2.5

The last sentence of the first paragraph in Section 2.2.5 says, "A change in the charge determinants for all LDCs (and not just HONI) as a result of the High 5 Proposal would likely have dramatic impacts on the cost responsibility among all customers."

Please clarify whether this sentence is intended to characterize Hydro One's views as expressed in EB-2008-0272 or is a statement of the Consultant's opinion? If it is intended to characterize Hydro One's views, please provide the appropriate references. if it is a statement of the Consultant's opinion, please provide supporting analysis, including assumptions, input data sets, calculations and results.

Response

This response is provided by Power Advisory.

Although the sentence is incorporated into a section intended to objectively report the comments of parties to EB-2008-0272, it is not reflected in comments filed by Hydro One and should be interpreted as a statement of the Power Advisory's opinion. The statement is based on Power Advisory's experience that a change in an allocation methodology from one that reflects demands throughout the year to one that reflects demands in relatively few hours within the year is likely to have dramatic cost responsibility impacts among customers. This statement is not based on an analysis of Ontario load data.

Association of Major Power Consumers of Ontario (AMPCO) INTERROGATORY #29 List 1

Interrogatory

8.1 Is it appropriate to implement "AMPCO's High 5 Proposal" in place of the status quo charge determinants for Network service?

Ref: Ex H1/Tab 3/Schedule 1/Attachment 1/Page 17/Section 2.3.1

Section 2.3.1 of the Consultant's report discusses consistency with cost responsibility principles. Please confirm that "cost responsibility" as used through the report, has the same meaning as "cost causality" in common usage before the Board. If not, please explain the difference.

Response

This response is provided by Power Advisory.

The term "cost responsibility" as used in the report refers to the outcome of rate design. The principal driver in the design of rates by regulatory agencies is a desire to reflect "cost causality" but there could be other factors that influence rate design, such as a desire to avoid rate shock to a particular group of customers.

<u>Association of Major Power Consumers of Ontario (AMPCO) INTERROGATORY #30 List 1</u>

Interrogatory

8.1 Is it appropriate to implement "AMPCO's High 5 Proposal" in place of the status quo charge determinants for Network service?

Ref: Ex H1/Tab 3/Schedule 1/Attachment 1/Page 18/Section 2.3.1

The Consultant report says, "However, HONI's transmission system does not peak at the same time in every area and regional peaks frequently occur on days that vary from the system peak days" and further provides that, "With respect to recovery of past investments, the transmission network was built to serve Ontario's transmission peak demands throughout the year and in each local region ..."

Please provide analysis, including relevant data sets, on which the Consultant relies to support these statements, including analysis based on actual historical demand showing when system peaks and local peaks, expressed in absolute terms, are most likely to occur.

Response

This response is provided by Power Advisory.

This assertion is based on our experience in Ontario and informed by our discussions with Hydro One transmission planners.

Association of Major Power Consumers of Ontario (AMPCO) INTERROGATORY #31 List 1

Interrogatory

8.1 Is it appropriate to implement “AMPCO’s High 5 Proposal” in place of the status quo charge determinants for Network service?

Ref: Ex H1/Tab 3/Schedule 1/Attachment 1/Page 18/Section 2.3.1

On page 18 (Section 2.3.1), Power Advisory states, “These resources tend not to experience their maximum output at the time of peak demands and the transmission network must be designed accordingly."

A) Please provide the data and analysis of generation technologies and fuel types in Ontario, identifying which generation produces what during peak times, including information related to installed and/or available capacity (MW) and production (MWh).

B) Please identify (by dollar value and proportion of total) the existing assets in the network pool that can be attributed to accommodating generation that experiences maximum output at times other than the time of peak demand.

Response

The response to part A is provided by Power Advisory.

A) Power Advisory has not developed these data. However, based on our professional experience all available generation types, except for the very highest cost generation resources or energy limited resources that are saving their output for the super-peak period, produce during peak times.

B) The transmission system is designed to accommodate a varying number of operating conditions, one of which is the need to accommodate generation connected to the system. Many factors affect the dispatch of generation including resource type and market conditions. Depending on the generation dispatch behaviour within and external to Ontario, different parts of the system may be stressed at periods that may not coincide with times of peak demand. The transmission system needs to accommodate a wide range of system conditions over time. As such, it is not possible to identify Network assets specifically attributable to the situation referenced.

Association of Major Power Consumers of Ontario (AMPCO) INTERROGATORY #32
List 1

Interrogatory

8.1 Is it appropriate to implement "AMPCO's High 5 Proposal" in place of the status quo charge determinants for Network service?

Ref: Ex H1/Tab 3/Schedule 1/Attachment 1/Page 18/Section 2.3.1/Footnote 61

The footnote says, "However, the circumstances in Ontario are distinct from those in the Northeast United States and Texas."

Please explain how and/or why Ontario is materially distinct.

Response

This response is provided by Power Advisory.

Please refer to Appendix B of the Power Advisory Report for a discussion of the potential relevance of the ERCOT and PJM experiences with similar rate design methodologies. Every region in North America has distinct demand and supply profiles, as well as different market organizations and rules, and policy drivers. However, as noted in the Power Advisory Report, Ontario is more likely to experience system peaks in the winter period than either PJM or Texas.

Association of Major Power Consumers of Ontario (AMPCO) INTERROGATORY #33 List 1

Interrogatory

8.1 Is it appropriate to implement "AMPCO's High 5 Proposal" in place of the status quo charge determinants for Network service?

Ref: Ex H1/Tab 3/Schedule 1/Attachment 1/Page 19/Section 2.3.2

The report says, "AMPCO essentially assumes that the current transmission shadow price is zero, thus overstating the price change used to calculate the elasticity response."

A) Please identify the number of customers in each month of 2007, 2008 and 2009, whose network charge determinant is based (i) on that customer's peak during the hour of system peak, or (ii) on 85% of the non-coincident peak during the working weekday hours 7:00 am to 7:00 pm.

B) Please compute the shadow price of network services for each customer in each month of 2007, 2008, and 2009, based on the data provided in (A).

Response

The response to part B is provided by Power Advisory.

A) Based on IESO invoice data, the attached table summarizes the number of Hydro One Transmission customer delivery points in each month for the years 2007 to 2009, whose network charge determinant was based on (i) CP or (ii) 85% NCP (7am to 7pm).

	2007		2008		2009	
	CP billed # of Del Pts	85% NCP billed # of Del Pts	CP billed # of Del Pts	85% NCP billed # of Del Pts	CP billed # of Del Pts	85% NCP billed # of Del Pts
Jan	431	118	402	155	426	128
Feb	419	125	406	144	423	130
Mar	424	123	388	166	412	146
Apr	345	208	379	183	390	178
May	358	197	355	207	295	273
Jun	390	165	393	168	390	175
Jul	422	129	398	161	391	182
Aug	395	161	375	195	419	157
Sep	394	168	390	180	360	217
Oct	297	258	412	155	390	181
Nov	416	139	405	160	421	146
Dec	415	139	369	190	418	148

B) Computing the shadow price of network services for each customer in each month would be a difficult and onerous undertaking.

Power Advisory understands “shadow price of network services” in this context to refer to the value to the customer of a 1 MW reduction in demand at the time of system peak (if the customer pays for network services based on monthly coincident peak) or at the time of its non-coincident peak demand (if the customer pays for network services based on the 85% ratchet.) Computing this value for each customer would require enough information to determine its demand at the time of the system peak as well as its own peak demand, in order to determine when the reduction has value. The computation would also require enough information to determine whether the reduction shifted the customer from ratchet to coincident peak when establishing their cost responsibility for network transmission charges.

Essentially, this would require hourly data for each month of the three years for the approximately 600 Hydro One delivery points. The analysis would then be done for each customer individually. This is an onerous task and the computations have not been done.

Association of Major Power Consumers of Ontario (AMPCO) INTERROGATORY #34 List 1

Interrogatory

8.1 Is it appropriate to implement "AMPCO's High 5 Proposal" in place of the status quo charge determinants for Network service?

Ref: Ex H1/Tab 3/Schedule 1/Attachment 1/Page 19/Section 2.3.2

The report says, "Even setting aside the relatively low explanatory power of the industry-specific equations, greater effort should be devoted to addressing potential econometric model specification problems."

Please identify the potential econometric model specification problems to which this statement refers.

Response

This response is provided by Power Advisory.

The most important econometric specification problem, as indicated by the low $R^{2,}$ is that important explanatory variables have been omitted. This equation uses only the price of the two inputs of off-peak and on-peak electricity (with some monthly dummies) to explain industrial electricity use. Since, as we point out in the answer to Exhibit I, Tab 9, Schedule 51, electricity is a factor of production, other explanatory variables could include factors influencing the firm's level of production or choice of inputs. For example, an activity variable such as demand for the firm's product should help explain its electricity use.

Second, the two independent variables chosen can be expected to be correlated with each other, rendering any estimated coefficients subject to unknown bias.

More broadly, the development of this econometric equation does not start with any model of the system to be estimated and therefore has no theoretical basis for the specification of the variables.

Association of Major Power Consumers of Ontario (AMPCO) INTERROGATORY #35 List 1

Interrogatory

8.1 Is it appropriate to implement "AMPCO's High 5 Proposal" in place of the status quo charge determinants for Network service?

Ref: Ex H1/Tab 3/Schedule 1/Attachment 1/Page 19/Section 2.3.3

Section 2.3.3 of the report reads in part, "Moreover, the econometric equation used to estimate this relationship is based on a data set that does not suffer from the same shortcomings of the industry-specific elasticity equations."

Please identify and describe the shortcomings to which this statement refers.

Response

This response is provided by Power Advisory.

This statement was meant to refer to the applicability of the results of the two sets of equations. The range of data in the estimation of the relationship between price and aggregate demand clearly included the levels of demand to which its coefficients were applied to estimate changes in price. However, the prices to which the coefficients of the demand equations were applied were well outside the range of the data used to estimate them. Extrapolation of empirically estimated structural coefficients so far beyond the range of data used to estimate them may produce invalid results.

Association of Major Power Consumers of Ontario (AMPCO) INTERROGATORY #36 List 1

Interrogatory

8.1 Is it appropriate to implement "AMPCO's High 5 Proposal" in place of the status quo charge determinants for Network service?

Ref: Ex H1/Tab 3/Schedule 1/Attachment 1/Page 19/Section 2.3.3

The report says, "Nonetheless, Power Advisory believes that an econometric model does not properly analyze the impact of relatively small changes in total demand."

A) Please clarify or confirm that it is the Consultant's opinion that no econometric model can be used to assess the impacts of small changes in demand.

B) Please clarify or confirm that it is the Consultant's opinion that econometric analysis, generally speaking, cannot be used to "properly analyze" the impact of small changes in demand.

C) Please identify and explain the Consultant's preferred methodology, approach or model to properly analyze the impact of small changes in demand, including an appropriate reference or source for the necessary data and assumptions to estimate such a model.

Response

The response to parts A, B and C are provided by Power Advisory.

A) It is not Power Advisory's opinion that no econometric model can be used to assess the impacts of small changes in demand. Where the supply curve has few flat areas representing the costs of large generators (that is, where the supply curve slopes smoothly upward) and the changes in demand are large enough to cause movement along the supply curve, an econometric model can be effective. Such a supply curve would represent a situation where an electricity supply system has a wide variety of suppliers with distinctly different cost functions.

B) That is not Power Advisory's opinion, as noted above in the answer to Part A).

C) Power Advisory's preferred methodology remains that chosen for, and reported on, in its report: the construction and use of an optimal-dispatch model with representation of the supply and demand conditions in the electricity system being modeled.

Association of Major Power Consumers of Ontario (AMPCO) INTERROGATORY #37 List 1

Interrogatory

8.1 Is it appropriate to implement "AMPCO's High 5 Proposal" in place of the status quo charge determinants for Network service?

Ref: Ex H1/Tab 3/Schedule 1/Attachment 1/Page 20/Section 2.3.5

A) Please provide any information that the Consultant or HONI has with respect to the prevalence of demand ratchets as a feature of network charges in other jurisdictions , in particular whether the use of ratchets is widespread, increasing or decreasing.

B) Please provide any comparative analysis, including assumptions, data sets, calculations and results that the Consultant has performed with respect to the effect of ratchets for network charges. Such comparative analysis may include before-and-after comparisons within a jurisdiction before and after adopting a ratchet or between jurisdictions with and without ratchets.

Response

The response to parts A and B are provided by Power Advisory, with input from Hydro One on part A.

A) Power Advisory did not gather information regarding the presence of demand ratchets in other jurisdictions. Based on a review of transmission tariffs in other jurisdictions completed in June of 2006, it is Hydro One's understanding that demand ratchets for Network Service exist in New Brunswick, Nova Scotia, New Zealand and for some utilities in Australia.

B) Power Advisory did not perform any comparative analysis regarding demand ratchets among jurisdictions.

Association of Major Power Consumers of Ontario (AMPCO) INTERROGATORY #38 List 1

Interrogatory

8.1 Is it appropriate to implement "AMPCO's High 5 Proposal" in place of the status quo charge determinants for Network service?

Ref: Ex H1/Tab 3/Schedule 1/Attachment 1/Page 20/Section 2.3.4

On page 20 (Section 2.3.4) of the report, Power Advisory states, "However, as discussed in Chapter 4, the transmission cost shift impacts from changing the methodology are quite dramatic and many times larger than the impact from load shifting…"

Please provide analysis, including assumptions, data sets, calculations and results, quantifying how much of the cost shifting as a result of changing the methodology can be attributed (i) to moving from a monthly 1CP charge determinant to an annual 5CP charge determinant, and (ii) to removing the 85% ratchet aspect of the current scheme.

Response

This response is provided by Power Advisory.

This statement is based on the more detailed discussion and quantitative analyses presented in Section 4 of the Power Advisory's report, and in particular a comparison of the impact of load shifting (as reported in Section 4.2) vs. the impact of a change in methodology (Section 4.3).

Power Advisory did not separately identify how much of the cost shifting from a change in methodology is attributable to removal of the demand ratchet.

Association of Major Power Consumers of Ontario (AMPCO) INTERROGATORY #39 List 1

Interrogatory

8.1 Is it appropriate to implement "AMPCO's High 5 Proposal" in place of the status quo charge determinants for Network service?

Ref: Ex H1/Tab 3/Schedule 1/Attachment 1/Page 20/Section 2.3.4

The Consultant's report states, "A central question is whether or not LDCs have the ability to respond to this impact by promoting load shifting by their customers."

Please explain whether, and, if so, how, the recent announcement by the Ontario Energy Board of new license conditions for LDCs relating to compulsory CDM targets to reduce demand measured during system peak times might be relevant to the "central question" posed by the Consultant.

Response

This response is provided by Power Advisory.

As described in Section 4.4, Power Advisory believes that there are actions that can be taken by LDCs, including changes in rate design and new programs, to promote load shifting. Certainly, the new licensing requirements are relevant to the extent that they promote similar objectives.

Association of Major Power Consumers of Ontario (AMPCO) INTERROGATORY #40 List 1

Interrogatory

8.1 Is it appropriate to implement "AMPCO's High 5 Proposal" in place of the status quo charge determinants for Network service?

Ref: Ex H1/Tab 3/Schedule 1/Attachment 1/Page 20/Section 2.3.5

The Consultant's report states, "The ratchet captures the fact that the transmission system has been built over time based on the need to meet system peaks but also to meet the peaks of large customers, regardless of when those peaks occur."

Please provide appropriate references to substantiate the statement of fact contained in this sentence.

Response

This response is provided by Power Advisory.

Demand ratchets ensure that customers make a contribution to the recovery of fixed costs even if they do not consume electricity during coincident peak periods, where such coincident peak periods are used to establish cost responsibility, as in Ontario.

Association of Major Power Consumers of Ontario (AMPCO) INTERROGATORY #41 List 1

Interrogatory

8.1 Is it appropriate to implement "AMPCO's High 5 Proposal" in place of the status quo charge determinants for Network service?

Ref: Ex H1/Tab 3/Schedule 1/Attachment 1/Page 22/Section 2.3.5.1

The Consultant's report states, "There may be other, more targeted approaches that accomplish greater demand response in a more efficient manner and without such unintended consequences."

Please explain the mechanism by which the Retail Transmission Service Rates charged by LDCs to Large Users and other monthly-billed customers are adjusted and how they might vary from the network charge determinant methodology approved by the Board for transmission customers.

Response

The Retail Transmission Service Rates (RTSR) charged by LDCs to Large Users and other monthly-billed customers are adjusted through a rate application by an LDC to the OEB. RTSR are adjusted at the same time as distribution rates are adjusted by distributors.

Distributors adjust the RTSR after new Uniform Transmission Rates (UTR) have been approved by the OEB. The OEB Guideline G-2008-0001 Revision 2.0, issued July 8, 2010, suggests that distributors adjust their RTSR for the new UTR levels and revenues generated from existing RTSR,

(http://www.oeb.gov.on.ca/OEB/_Documents/Regulatory/Guideline_G-2008-0001_EDRTSR.pdf).

The RTSR Network charge determinants applied by distributors are described in the First Generation Performance Based Regulation for Electricity Distributors - Distribution Rate Handbook, Chapter 11, section 11.3.2.5 Charge Determinants, Retail Transmission Network Service Rate:

(http://www.oeb.gov.on.ca/documents/cases/RP-1999-0034/chapter11_revision2.pdf)

> "*For an interval metered customer, the network rate will apply to an individual end-use customer's non-coincident peak demand in the month during the peak period defined as between 7 AM and 7 PM on weekdays that are not statutory holidays. For end-use customers with non-time-of-use demand meters, the network charge rate will apply to the customer's peak demand during the billing period. For customers with energy only meters, the network charge rate will be based on monthly energy, adjusted for losses, subject to a distributor's election under section 11.3.2.4.*"

Transmission connected customers are billed for Networks charges based on the highest of:

- Customers' demand at the time of the monthly coincident peak demand during the peak hours during business days, and
- 85% of maximum non-coincident demand during peak hours during IESO business days.

Transmission connected customers and demand billed distributors' customers are both billed based on monthly consumption, but demand billed distributors' customers are not billed based on coincident demand and are not subject to the 85% demand ratchet when they are billed for RTSR.

Association of Major Power Consumers of Ontario (AMPCO) INTERROGATORY #42
List 1

Interrogatory

8.1 Is it appropriate to implement "AMPCO's High 5 Proposal" in place of the status quo charge determinants for Network service?

Ref: Ex H1/Tab 3/Schedule 1/Attachment 1/Page 23/Section 2.3.5.2

The Consultant's report states, "For example, an increase in demands placed on the transmission network from extreme weather may lead to greater unplanned outages of equipment that requires maintenance, repair or replacement that exceed the budgeted amounts."

Please explain, with supporting analysis, whether the AMPCO proposal is more or less likely, compared to the current scheme, to create incentives for demand response during periods of extreme weather-related increases in demand.

Response

This response is provided by Power Advisory.

The High 5 proposal will provide a greater incentive for demand response during extreme weather than the current rate design methodology, particularly for customers that correctly anticipate the transmission price signal and have the ability to modify their usage patterns. It is likely that extreme weather conditions will provide a signal to these customers that both their energy and transmission charges are likely to be effected by such conditions.

<u>Association of Major Power Consumers of Ontario (AMPCO) INTERROGATORY #43 List 1</u>

<u>Interrogatory</u>

8.1 Is it appropriate to implement "AMPCO's High 5 Proposal" in place of the status quo charge determinants for Network service?

Ref: Ex H1/Tab 3/Schedule 1/Attachment 1/Page 24/Section 2.3.5.2

The Consultant's report states, "The determination of the High 5 hours, and network charge determinants would not be available until some time after the beginning of the year. As it is possible that a High 5 hour could occur in January or February, it is important the new rates be established as early in the year as possible. If this can only be accomplished with a hearing process, in order for stakeholders to comment on the calculations, then this becomes problematic."

A) Please provide analysis, including assumptions and data sets, in support of the statement that the determination of the High 5 hours would not be available until "some time" after the end of the year.

B) Under the High 5 proposal, a customer's charge determinant is based on demand in the previous year. Please explain why the High 5 could not be implemented in a way that is consistent with the notion that "it is important that new rates be established as early in the year as possible".

C) Please confirm that the Consultant expects that new rates would necessarily be set through an annual hearing process.

Response

The response to parts A, B and C are provided by Power Advisory.

A) and B)

Final hourly demands for a calendar year are generally not available until settlement and verification activities have been performed and would not be available on December 31. However, Hydro One has subsequently discussed this issue with the IESO and confirmed that once the IESO has completed all the necessary system changes to be able to bill customers for Network costs based on the High Five proposal, the required data would be available in time to calculate January bills based on the High 5 peaks that occurred in the preceding year.

C) Power Advisory agrees that a regulatory action is necessary to recalculate rates. However, Power Advisory does not have an opinion with respect to the complexity of such a process, the degree of stakeholder involvement, or the necessity of hearings.

Association of Major Power Consumers of Ontario (AMPCO) INTERROGATORY #44 List 1

Interrogatory

8.1 Is it appropriate to implement "AMPCO's High 5 Proposal" in place of the status quo charge determinants for Network service?

Ref: Ex H1/Tab 3/Schedule 1/Attachment 1/Page 27/Section 3.1.1, first bullet

The first bullet under section 3.1.1 on page 27 reads, "The customer cannot know when its reduction in demand will actually affect its network transmission costs, and…"

Please explain this statement.

Response

This response is provided by Power Advisory.

Under the AMPCO proposal the High 5 hours are established at the end of the year. Therefore, customers would not know with certainty whether a reduction in demand in a specific hour in the current year is likely to affect their network transmission costs for the subsequent year.

Association of Major Power Consumers of Ontario (AMPCO) INTERROGATORY #45
List 1

Interrogatory

8.1 Is it appropriate to implement "AMPCO's High 5 Proposal" in place of the status quo charge determinants for Network service?

Ref: Ex H1/Tab 3/Schedule 1/Attachment 1/Page 31/Section 3.1.3

The last sentence on page 31 reads, "In a year with particularly mild summer weather, a high 5 load hour could be experienced in May or September."

Please provide an analysis, based on weather-normalized load data, of which months are most likely to experience the highest five hourly demands.

Response

Power Advisory doesn't have weather-normalized load data. Under the High 5 proposal network charges would be allocated based on actual peak loads, not weather-normalized data.

Association of Major Power Consumers of Ontario (AMPCO) INTERROGATORY #46 List 1

Interrogatory

8.1 Is it appropriate to implement "AMPCO's High 5 Proposal" in place of the status quo charge determinants for Network service?

Ref: Ex H1/Tab 3/Schedule 1/Attachment 1/Page 32/Section 3.1.3/Footnote 83

Please clarify the year based on which the 1912 MW figure was calculated.

Response

The 1,912 MW figure was based on High 5 loads from 2003 through 2009.

Association of Major Power Consumers of Ontario (AMPCO) INTERROGATORY #47 List 1

Interrogatory

8.1 Is it appropriate to implement "AMPCO's High 5 Proposal" in place of the status quo charge determinants for Network service?

Ref: Ex H1/Tab 3/Schedule 1/Attachment 1/Page 32/Section 3.1.3/Footnote 84

Please provide the data/analysis or an appropriate reference for the 550 MW per degree Celsius figure.

Response

This response is provided by Power Advisory.

This figure is used by OPG in its demand forecasting for Ontario. The IESO forecasts peak load using a heat and humidity index which considers both temperature and humidity (measured as dewpoint). The IESO estimates that peak load increases by 450 MW for each degree C above 16 degrees C and by 160 MW for each degree increase in the dewpoint above 16 degrees C. Recognizing that high temperatures and humidity are highly correlated supports the 550 MW per degree Celsius figure estimated by OPG.

Association of Major Power Consumers of Ontario (AMPCO) INTERROGATORY #48
List 1

Interrogatory

8.1 Is it appropriate to implement "AMPCO's High 5 Proposal" in place of the status quo charge determinants for Network service?

Ref: Ex H1/Tab 3/Schedule 1/Attachment 1/Page 36/Section 3.2.1

The Consultant's report states, "For the analysis of the AMPCO High 5 proposal, the appropriate elasticity of substitution is therefore the elasticity of substitution between peak and off-peak electricity."

Please provide the analysis deriving elasticity of substitution values from data from the most recent 3 years. Include data sets and calculations supporting the analysis.

Response

This response is provided by Power Advisory.

Power Advisory did not perform any analysis deriving elasticity of substitution values.

Association of Major Power Consumers of Ontario (AMPCO) INTERROGATORY #49 List 1

Interrogatory

8.1 Is it appropriate to implement "AMPCO's High 5 Proposal" in place of the status quo charge determinants for Network service?

Ref: Ex H1/Tab 3/Schedule 1/Attachment 1/Page 37/Section 3.2.1

"Under the AMPCO High 5 proposal, the effective price at the time of load shifting is not well known until after the fact."

Please clarify and/or describe the time frame within which a customer can reasonably be expected to know the effective price, financial impact, or benefit, of load shifting.

Response

This response is provided by Power Advisory.

Please see Exhibit I, Tab 9, Schedule 44.

Association of Major Power Consumers of Ontario (AMPCO) INTERROGATORY #50 List 1

Interrogatory

8.1 Is it appropriate to implement "AMPCO's High 5 Proposal" in place of the status quo charge determinants for Network service?

Ref: Ex H1/Tab 3/Schedule 1/Attachment 1/Page 37/ Section 3.2.1

On page 37 of the report, Power Advisory states, "In essence, customers have to incur costs in the hope of reducing costs…."

Please explain, and provide examples, of the costs that customers might incur to reduce demand during system peak periods.

Response

This response is provided by Power Advisory.

Costs that customers might incur to reduce demand include increased labour costs from changing shift schedules, higher production costs from not having necessary inputs available as a result of rescheduling the production and storage and inventory costs for holding output shifted to off-peak periods.

Association of Major Power Consumers of Ontario (AMPCO) INTERROGATORY #51 List 1

Interrogatory

8.1 Is it appropriate to implement "AMPCO's High 5 Proposal" in place of the status quo charge determinants for Network service?

Ref: Ex H1/Tab 3/Schedule 1/Attachment 1/Page 38/Section 3.2.2

On page 38, the Consultant's report states, "Chief among the problems is the lack of a properly formulated production function to constrain the system and the failure to consider that the response to price change is to change the ratios of the inputs. The customer is reacting to a change in the relative price of two of its inputs by rebalancing their use, shifting away from the one that became relatively more expensive and towards the one that is now relatively cheaper. At the same time, we are assuming that the customer plans to maintain its total output, which places a restriction on the way that the substitution occurs. To represent this situation properly requires development of a production function in a form consistent with the assumptions. Dr. Sen failed to construct any production function and therefore places no constraints on the results."

Please provide the economic theory behind using a production function with respect to analyzing consumption data.

Response

This response is provided by Power Advisory.

For industrial customers, electricity is a factor of production. The amount of electricity a customer uses depends on the technical and price relationships between electricity and the other factors of production; in other words, on the production function.

Association of Major Power Consumers of Ontario (AMPCO) INTERROGATORY #52 List 1

Interrogatory

8.1 Is it appropriate to implement "AMPCO's High 5 Proposal" in place of the status quo charge determinants for Network service?

Ref: Ex H1/Tab 3/Schedule 1/Attachment 1/Page 38/ Section 3.2.2

A) Please provide data and/or analysis to support the assumption that customers who undertake load shifting will be constrained by maintaining output constant.

B) Please explain whether the assumption requires daily output to be held constant, or output within a week, month, quarter or year.

C) Please provide data, or appropriate references to a source of publicly available data, that would enable the following proposed models to be estimated: (i) a production function with a constant output constraint, or (ii) a production function with a constant electricity budget constraint.

D) Please explain how a firm production function can be used to estimate aggregate industry responses to changes in relative prices.

Response

The response to all parts is provided by Power Advisory.

A) Power Advisory does not assume customers will be constrained to maintain constant output. As discussed in Exhibit I, tab 9, Schedule 53, we expect that the customer would not want to change output, since its demand has not changed and its costs have, if anything, decreased. Power Advisory said that the model system underlying the empirical estimation should be constrained to hold output constant to represent the conditions of production for the firm.

B) The constrained function would hold output constant over the period of shifting, in this case over a day.

C) Power Advisory has no such data. Such studies have generally not used publicly available data but rather have had access to individual customer data.

D) The responses to changes in relative prices are estimated from the empirical results of econometric estimation of the demand equations derived from the production functions of the firms.

Association of Major Power Consumers of Ontario (AMPCO) INTERROGATORY #53
List 1

Interrogatory

8.1 Is it appropriate to implement "AMPCO's High 5 Proposal" in place of the status quo charge determinants for Network service?

Ref: Ex H1/Tab 3/Schedule 1/Attachment 1/Page 38/ Section 3.2.2

The report states, "This would imply that the customer is reducing its output in response to the transmission price increase, which violates the assumptions of the analysis".

Please clarify that the analysis of which the assumptions are supposed to be violated in this sentence refers to the hypothetical analysis of a production function model as recommended by the Consultant, and not to any analysis which has actually been performed by AMPCO.

Response

This response is provided by Power Advisory.

The change in network transmission pricing does not change the conditions of demand for the company. It also should not increase the company's costs; in fact, it should decrease the cost. Since the company's overall demand curve has not changed, and its supply curve has if anything shifted downward, the assumption is that it will maintain its level of output. In making temporary shifts of production from peak to off-peak, the company is not likely to be changing its production technology so as to change the electricity/output ratio. Therefore, the expectation is that the company will keep its total electricity use for production of goods unchanged.

AMPCO made a similar assertion. In AMPCO's report, it stated "Intuitively one can understand that where a customer reduces demand during peak hours, lost production must be made up during off-peak hours." [1]

[1] AMPCO, "The Benefits of Improvement in Transmission Rage Design", pg. 7

Association of Major Power Consumers of Ontario (AMPCO) INTERROGATORY #54 List 1

Interrogatory

8.1 Is it appropriate to implement "AMPCO's High 5 Proposal" in place of the status quo charge determinants for Network service?

Ref: Ex H1/Tab 3/Schedule 1/Attachment 1/Page 38/Section 3.2.2, second bullet

The report asserts, "There is multicollinearity because the independent variables are correlated with each other, but Dr. Sen did not report the degree of correlation. Multicollinearity can make the coefficient estimates suspect in relation to each other."

Please provide analysis, including assumptions, data sets, and calculations, demonstrating such multicollinearity.

Response

This response is provided by Power Advisory.

Such an analysis would require access to AMPCO's data to compute the correlations among the independent variables. Power Advisory does not have these data. As Power Advisory noted in its report, Dr. Sen said the independent variables are correlated, which is the definition of multicollinearity. (AMPCO response to IR from VECC, EB-2008-0272, Exhibit I, Tab 17, Schedule 4, pg. 7)

Association of Major Power Consumers of Ontario (AMPCO) INTERROGATORY #55 List 1

Interrogatory

8.1 Is it appropriate to implement "AMPCO's High 5 Proposal" in place of the status quo charge determinants for Network service?

Ref: Ex H1/Tab 3/Schedule 1/Attachment 1/Page 39/ Section 3.2.2, first bullet

The first bullet on page 39 reads, "Dr. Sen's estimated coefficients are not robust under different estimation time frames and different specification of the independent variables."

A) Please clarify that by "robust", the Consultant means "the same", or if a different meaning is intended please explain what the statement is intended to express.

B) If by "robust", the Consultant means "the same", please explain why one would expect that coefficients estimated using different data sets, based on different assumptions, according to models specified differently, should be the same.

Response

The response to parts A and B are provided by Power Advisory.

A) In this case, "robust" was used to mean an estimate that is not sensitive to changes in the data or time frame chosen for the estimation.

B) Power Advisory did not mean "the same".

Association of Major Power Consumers of Ontario (AMPCO) INTERROGATORY #56 List 1

Interrogatory

8.1 Is it appropriate to implement "AMPCO's High 5 Proposal" in place of the status quo charge determinants for Network service?

Ref: Ex H1/Tab 3/Schedule 1/Attachment 1/Page 41/ Section 3.2.3/Footnotes 103 & 106

Please provide copies of the reports cited in footnotes 103 and 106.

Response

This response is provided by Power Advisory.

The Deal and Mountain study (Footnote 103) is available from the IESO website at http://www.ieso.ca/imoweb/marketsAndPrograms/MEAR_publications.asp

The Cheng and Mountain study (Footnote 106) is provided as an attachment to this interrogatory response.

Econometric Study of the 1992 Time-Of-Use Impact on Direct Industrial Customers
March 1993

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March, 1993

File Number 570.1N (542)

EXECUTIVE SUMMARY

From 1989 until 1992 there has been a de-emphasis of the demand charge and energy rates have been time differentiated. Higher rates are charged during the peak periods on weekdays and in the winter relative to the summer.

With econometric models, the TOU impacts on Ontario Hydro's direct industrial customers are estimated by controlling for other factors such as economic fluctuations and relative wage differentials. This report presents the 1992 cumulative and net TOU impacts on direct industrial customers. The study confirms that there were TOU impacts on half of the direct customers.

The 1992 cumulative 16-hour December Peak TOU impacts on direct industrial customers was approximately a 39.5 MW or 2.1% reduction. This was a decrease in TOU impact since the corresponding 1991 impact was a 45.8 MW or 2.4% reduction. At the industry level, the largest shifter was the Mining industry with a 18.88 mw reduction. It was followed by the Paper & Allied industry with a 7.09 mw reduction. Direct customers from the Non-Metallic Mineral, Primary Metal and Fabricated Metal Products industries also shifted more than 2 mw each.

On the energy side, the reduction in the overall winter energy consumption (15,130 average monthly Mwh) was coupled with an increase in the overall summer energy consumption (12,951 average monthly Mwh). This translated to an annual average monthly reduction of 1,089 Mwh for all direct customers in 1992.

Since direct customers in some industries represented the majority of these industries' load, we have reported their results as industry results in addition to firms' results. We have also reported the underlying firm and industry elasticities. Beside being valuable for ex-post assessment, the models and their results (eg. elasticities) are of value for scenario and simulation purposes. Different price and economic structure scenarios can be simulated.

ACKNOWLEDGEMENT

We would like to thank Louis Neretlis for computer programming. We thank Jim Pressnail and Gary Timoshenko for their contribution to data collection. We would also like to thank Jing Zhu for her dedication in the initial stages of the project. Kathy Chan's co-ordination of the computerization and data collection was very helpful.

We greatly appreciate Bob Bryniak's (Industrial Program Section) continuous moral and financial support for this project. We are grateful to Ralph Whiting, Paul Burke, Bill Harper and others for their valuable comments. Mike Roger's advice for creating non Time-of-Use price scenarios has been most helpful. In addition, this report would not have been possible without the on-going direction, commentary and financial support of Neil Mather of Load Analysis Section and Takis Plagiannakos of Energy Economics Section.

TABLE OF CONTENTS

1.0 Introduction

Until 1989, for its large industrial customers (known as directs), Ontario Hydro had a Hopkinson Structure which consisted of a monthly demand charge and a uniform energy rate. For the maximum 1-hour use the demand charge was paid, and a uniform energy charge was paid across the month and over all months of the year. From 1989 and on, there has been a de-emphasis of the demand charge and energy rates have become time differentiated. Higher rates are charged during the peak time period on weekdays (7 am - 11 pm) and in the winter relative to the summer. Table 1 provides a description of the rate structure.

Because of the multi-dimensional aspects of the rate structure, we find it convenient, at least on the energy side, to focus on two aspects of the resultant impact, the impact on time-of-day consumption and the impact on overall consumption. First, because of the widening peak:off-peak price differential we would expect some reduction in peak consumption and increase in off-peak consumption. Second, because of the higher winter seasonal rates we would expect some conservation to occur in the winter - in both the peak and perhaps the off-peak. In the summer, the generally lower rates coming from the summer seasonal rates and perhaps even from shifting into cheaper off-peak electricity could result in an overall consumption increase. In addition, we must also consider the impact of de-emphasizing the demand charge. This would encourage higher one-hour peak demand and less energy. In all, we can summarize the partial expected impacts in Table 2. Many of the net impacts, with the exception of peak energy consumption in the winter and peak demand in the summer, are in doubt.

The purpose of this report is to econometrically quantify the impact of the rate structure up to 1992 for direct customers. Since direct customers in some industries represented the majority of the industries' load, we can report their results as industry results. Individual customer results are provided in the Appendix. The TOU impacts estimated in this report were due to the TOU rate structure and net of economic fluctuations. We modelled customers responses to TOU while controlling for other non-price variables such as economic variables.

TABLE 1
COMPARISON OF RATES FOR DIRECT INDUSTRIAL CUSTOMERS

1989

	NON-TOU		TOU	
Monthly Demand Rates ($/KW)*	Winter	Summer	Winter	Summer
230 KV	8.77	8.77	9.02	7.10
115 KV	9.04	9.04	9.29	7.37
Less than 115 KV	9.73	9.73	9.98	8.06
Energy Rates (cents/kwh)				
Peak	2.36	2.36	3.06	2.79
Off-Peak	2.36	2.36	2.39	1.86

1990

	NON-TOU		TOU	
Monthly Demand Rates ($/KW)*	Winter	Summer	Winter	Summer
230 KV	9.25	9.25	9.55	7.13
115 KV	9.55	9.55	9.85	7.43
Less than 115 KV	10.34	10.34	10.64	8.22
Energy Rates (cents/kwh)				
Peak	2.49	2.49	3.35	2.98
Off-Peak	2.49	2.49	2.56	1.92

1991

	NON-TOU		TOU	
Monthly Demand Rates ($/KW)*	Winter	Summer	Winter	Summer
230 KV	9.97	9.97	10.49	7.48
115 KV	10.29	10.29	10.77	7.76
Less than 115 KV	11.15	11.15	11.51	8.50
Energy Rates (cents/kwh)				
Peak	2.68	2.68	3.76	3.32
Off-Peak	2.68	2.68	2.82	2.02

1992

	NON-TOU		TOU	
Monthly Demand Rates ($/KW)*	Winter	Summer	Winter	Summer
230 KV	11.15	11.15	11.59	7.96
115 KV	11.50	11.50	11.93	8.80
Less than 115 KV	12.47	12.47	12.83	9.20
Energy Rates (cents/kwh)				
Peak	3.00	3.00	4.31	3.75
Off-Peak	3.00	3.00	3.18	2.18

* Billing demand rate applies to the peak period under the TOU rate, and to the peak regardless when it occurs under the NON-TOU rate.

TABLE 2
QUALITATIVE IMPACTS OF
DIRECT INDUSTRIAL RATE STRUCTURES

Winter Impact of/on	Demand	Peak Energy	Off-Peak Energy
Time-Of-Day Differentials	0	-	+
Seasonal Differentials	-	-	-
De-emphasis of Demand Charge	+	-	-
Net Effect	?	-	?

Winter Impact of/on	Demand	Peak Energy	Off-Peak Energy
Time-Of-Day Differentials	0	-	+
Seasonal Differentials	+	+	+
De-emphasis of Demand Charge	+	-	-
Net Effect	+	?	?

2.0 **Methodology and Selection Criteria**

Under time-of-use rates, in a given month the industrial customer pays a one-hour peak demand charge (PKW) for maximum one-hour consumption (KW). The customer also pays a peak-energy charge (PKWP) for peak energy consumption (KWHP) and an off-peak energy charge (PKWHOP) for off-peak energy consumption (KWHOP). For this analysis we create mutually exclusive commodities - excess demand (X1=KW-KWHP/352), peak energy (X2=KWHP), and off-peak energy (X3=KWHO). The respective prices of these mutually exclusive commodities are P1=PKW, P2=PKWHP+PKW/352 and P3=PKWHO. For the interruptible customers, marginal (interruptible) rates are used.

In our analysis we viewed firms as choosing their individual electricity components, excess demand (X1), peak energy (X2) and off-peak energy (X3) to minimize their electricity expenditure subject to delivering a certain level of electricity service (E). We model (Xi/X1) as a function of P1, P2, P3, W1, W2, W3, SH, SP, T and E where the Wi (i=1,2,3) reflect wages during the day, afternoon and night, SH is the level of shipments, SP is a splined monthly dummy and T is time which represents technological or structural change. Furthermore, we model E as a function of P, W1, W3, W3, SH, SP and T where P is an overall price index of electricity (e.g. $\ln P = \Sigma^3_{i=1}(PiXi/\Sigma PjXj)\ln Pi$). See Mountain and Zhu (1991) for a more detailed discussion of the econometric methodology.

There are two tiers for measuring responsiveness to TOU rates. Immediately below we will describe how we will select empirical functions (a two-equation model) to allocate the TOU impacts on the electricity components (e.g. off-peak kwh:peak kwh, excess demand:peak kwh). Of course, there is the possibility that TOU rates influence the firm's electricity consumption even though ratios of components do not change. To account for this, we add a single equation model (Aggregate Electricity Demand model) to account for impacts on total electricity consumption due to the possible change in overall electricity price index relative to prices of other forms of energy. From here on we will refer to this as the relative energy price effect. We will now describe briefly our modelling of the three electricity components.

As mentioned in Mountain and Zhu (1991), given our lack of knowledge about the actual representation between a target set of inputs and a set of independent variables and given the potential limited degree of variation in the data, we use a combined structural and flexible approach. We will try to let the data speak for itself but will also where possible, use economic theory to select simple (as opposed to more complicated) modelling systems. Even where we consider more structural models we will be comparing them with an unrestricted functional form where the data is allowed to speak for itself. While the dependent variable of the structural models is (Xi/X1), the dependent variable of the flexible model is (Si) which represents the share of cost for each commodity. Please see Mountain and Zhu (1991) for details.

Given that we are uncertain about whether TOU rates matter or not, we will cautiously begin with two of the simplest functional forms which display no substitution response to TOU rates (Leontief) and an elasticity of substitution equal to 1 (Cobb-Douglas). If one of the above functional forms does not statistically significantly differ from an unrestricted data describing functional form, it is selected as the appropriate functional form. Otherwise, we continue by testing the Constant Elasticity of Substitution and Linear Constant Relative Share formulations of the Quasi Cobb-Douglas specification. We begin by conducting the above tests under the assumption of Hicks neutral technological change. If all of the above cases are rejected, the procedure is duplicated to allow for technological change.

If none of the above models is selected, we then perform a similar search on more flexible Translog specifications. Here we begin by testing for the presence of Cobb-Douglas and proceed to the more general Translog case. Again, the same test for technology is applied as just described. In all of the above, a function displaying Hicks neutral technological change is chosen over that with some biased form of technological change. This is consistent with our simplicity tenet. If no functional form is chosen that satisfies the above condition, we then use the Akaike Information Criteria (AIC) and choose the functional form with the lowest AIC test-statistic.

Some further comments on the specification search deserve mentioning. To balance "the desirability of not estimating an overparameterized model with the sensitivity of the procedure of rejecting a false null hypothesis", (Mountain and Hsiao 1989), we allow for higher type-I errors in testing more restrictive functional forms. (e.g. Leontief, Cobb-Douglas). Furthermore, given our prior view that firms either do not respond or indeed move their electricity consumption from the peak to the off-peak (and not vice versa), we never choose a functional form with negative own-price elasticity of demand.

3.0 DATA

Data periods are 1982-1992 or 1985-1992 depending on the availability of data for customers. The data sources are as follows: load data from the Program Testing and Analysis Department, electricity prices from the Rate Structures Department, shipments data and industrial selling price indexes from Statistics Canada, firm-specific wage data from the Ontario Ministry of Labour.

4.0 RESULTS

This report will focus on the 1992 cumulative and net TOU impacts. Highlights of the results are summarized in the following sections while details of the results can be found in Appendix A. As Table 3 indicates, direct customers represented significant load contributions (about or above 50%) in the Mining, Primary Textile, Paper and Allied, Non-Metallic Mineral, Refined Petroleum and Coal and Chemical and Chemical Products industries. Therefore, discussion will concentrate on these industries.

4.1 MODEL

4.1.1 Model Selection

As mentioned in the methodology section, customers' TOU responses are assessed according to their conformity with the given list of two-equation functional forms as well as their sensitivity to changes in relative energy prices in the Aggregate Electricity Demand model. Five functional forms were identified (see Table 4). They were Leontief, CES, Linear, Cobb-Douglas, and Translog.

Leontief customers are insensitive to the price differential between the peak and off-peak periods and do not shift electricity consumption after the implementation of TOU rates. Sixty six customers were identified with Leontief functional forms and were distributed across industries.

The 36 customers which responded to the TOU price differential could be grouped under four different functional forms. While CES, Linear and Cobb-Douglas reflect constant elasticity of substitution between the three electricity commodities, Translog suggests a range of elasticities of substitution between the commodities.

As the TOU rates are implemented, customers may change their overall electricity consumption because of the change in relative energy prices. The Aggregate Electricity Demand Model helped to determine 29 customers' responsiveness to changes in relative energy prices (see Table 5). Twenty two of them were Leontief customers. Essentially, they changed their overall consumption levels but did not change their profiles. The remaining seven also responded to the TOU price differential and changed their profiles.

TABLE 3
1991 ELECTRICITY DEMAND
GWH

SIC	INDUSTRY	DIRECT CUSTOMERS GWH	DIRECT CUSTOMERS AS A % OF ONTARIO TOTAL	LARGE CUSTOMERS GWH	LARGE CUSTOMERS AS A % OF ONTARIO TOTAL	OTHERS GWH	OTHERS AS A % OF ONTARIO TOTAL	ONTARIO TOTAL
6	Mining	4698	93	0	0	351	7	5049
10	Food	83	4	331	17	1521	79	1935
15	Rubber	36	5	222	29	513	67	770
18	Primary Textile	138	67	0	0	69	33	207
25	Wood	16	4	0	0	361	96	377
26	Furniture & Fixture	0	0	0	0	199	100	199
27	Paper & Allied	5195	83	643	10	395	6	6233
29	Primary Metal	1414	28	2968	60	589	12	4970
30	Fabricated Metal Products	315	18	30	2	1428	81	1772
32	Transportation Equipment	804	21	2069	53	1002	26	3875
33	Electrical and Electronic	45	3	352	26	984	71	1382
35	Non-Metallic Mineral	1040	44	720	30	630	26	2390
36	Refined Petroleum and Coal	1781	76	312	13	255	11	2349
37	Chemical & Chemical Products	2694	62	854	20	781	18	4329
49	Other Utility	55	5	0	0	947	95	1002
81	Federal Government Service	115	100	0	0	0	0	115
	Others	0	0	331	8	3807	92	4138
	TOTAL	18428	45	8833	21	13832	34	41092

TABLE 4
MODEL SELECTION

SIC	INDUSTRY	NUMBER OF CUSTOMERS	LEONTIEF	COBB CES	DOUGLAS	TRANSLOG	LINEAR	UNKNOWN
6	Mining	23	12	5	4	0	1	1
18	Primary Textile	2	1	1	0	0	0	0
27	Paper & Allied	24	14	3	2	3	1	1
35	Non-Metallic Mineral	13	9	2	1	0	0	1
36	Refined Petroleum and Coal	5	5	0	0	0	0	0
37	Chemical & Chemical Products	17	13	2	1	0	0	0
OTHERS								
10	Food	1	1	0	0	0	0	0
15	Rubber	1	0	0	0	0	1	0
25	Wood	1	1	0	0	0	0	0
29	Primary Metal	8	5	1	2	0	0	0
30	Fabricated Metal Products	1	0	1	0	0	0	0
32	Transportation Equipment	4	4	0	0	0	0	0
33	Electrical and Electronic	1	0	0	0	0	1	0
49	Other Utility	2	0	2	0	0	0	0
81	Federal Government Service	3	1	0	2	0	0	0
	TOTAL	106	66	17	12	3	4	4

Unknown: Model cannot be estimated due to data problems

TABLE 5
AGGREGATE ELECTRICITY DEMAND MODEL
(AEDM)

SIC	INDUSTRY	NUMBER OF CUSTOMERS	TOTAL SIGNIFICANT AEDM	AEDM WITH LEONTIEF	AEDM WITH OTHER MODELS
6	Mining	23	7	4	3
18	Primary Textile	2	1	1	0
27	Paper & Allied	24	6	5	1
35	Non-Metallic Mineral	4	5	4	1
36	Refined Petroleum and Coal	5	0	0	0
37	Chemical & Chemical Products	17	2	1	1
OTHERS					
10	Food	1	0	0	0
15	Rubber	1	0	0	0
25	Wood	1	1	1	0
29	Primary Metal	8	3	3	0
30	Fabricated Metal Products	1	0	0	0
32	Transportation Equipment	4	3	3	0
33	Electrical and Electronic	1	1	1	0
49	Other Utility	2	0	0	0
81	Federal Government Service	3	0	0	0
	TOTAL	106	29	22	7

Source: Energy Economics Section, Economics & Forecasts Division

4.1.2 Model Statistics

In estimating the system of relative electricity inputs, it is inevitable that econometrically estimated consumption will differ from the actual by an error. Because the overshooting of one set of relative inputs results in the undershooting of another set, the respective errors are correlated. This cross-covariance of errors is accounted for in the full information maximum likelihood estimation procedure. Given this estimation procedure there are various ways one might measure goodness of fit. We can certainly report the equation-by-equation R-square. The advantage of this is that we are measuring the variation in relative inputs in their original units. On the other hand, the estimation procedure involves a criterion of minimizing a weighted variation in relative inputs. Consequently, another relevant R-square is a system R-square which incorporates these weights (which are functions of the error-covariance structure) (see Judge, Griffiths, Hill, Lutkepohl and Lee, (1985). Both types of R-square are reported in Table 6 (see Table A2 for details). Given the criterion of estimation, it is not surprising that the system R-squares are usually high (around 0.95). The average R-square for the individual equations is 0.40. This is not unusual for monthly system models.

In addition to electricity prices, other non-price economic factors such as shipments, wages and seasonality affect customers' ability to shift out of the peak period. Although separately only about 31% of the non-price variables had effects on customers electricity consumption, jointly 58% of them exhibited such influence. The Primary Textile and Paper & Allied industries seemed to be strongly affected by non-price economic factors (see Table 6).

Shipments have the weakest relationship with customers demand for electricity for two reasons. Although the variable "shipments" on average is the closest proxy to output, it may not be true for some customers. Furthermore, industry shipments data, rather than customer-specific shipment data, are used. Therefore, some shipments data cannot help to explain customers' demand for electricity when customers' shipments are very different from a constant fraction of industry shipments.

TABLE 6
MODEL STATISTICS

SIC	INDUSTRY	NUMBER OF CUSTOMERS	CUSTOMER WITH SIGNIFICANT NON-PRICE ECONOMIC VARIABLES: SHIPMENTS	WAGE	SEASONAL DUMMY	JOINT	SYSTEM R-SQUARE	R-SQUARE EQ1	R-SQUARE EQ2
6	Mining	23	5	7	10	14	0.96	0.37	0.39
18	Primary Textile	2	2	1	2	2	0.99	0.57	0.57
27	Paper & Allied	24	13	6	10	18	0.96	0.31	0.37
35	Non-Metallic Mineral	13	3	3	4	8	0.94	0.28	0.33
36	Refined Petroleum and Coal	5	0	0	1	1	0.99	0.21	0.21
37	Chemical & Chemical Products	17	2	6	1	6	0.91	0.27	0.28
OTHERS									
10	Food	1	0	1	1	1	0.98	0.37	0.41
15	Rubber	1	0	0	0	0	0.99	0.58	0.72
25	Wood	1	0	0	0	0	0.99	0.43	0.39
29	Primary Metal	8	3	6	1	5	0.96	0.37	0.35
30	Fabricated Metal Products	1	1	1	0	1	0.96	0.35	0.47
32	Transportation Equipment	4	2	1	2	3	0.99	0.48	0.45
33	Electrical and Electronic	1	0	0	1	1	0.99	0.38	0.37
49	Other Utility	2	0	0	0	0	0.68	0.35	0.33
81	Federal Government Service	3	0	1	1	1	0.97	0.52	0.59
	TOTAL	106	31	33	34	61	0.95	0.39	0.41

Source: Energy Economics Section, Economics & Forecasts Division

4.2 TOU Elasticities

The demand for a product may vary when its own price changes, or the price of its substitute changes, or both. Elasticities are the measures of the responsiveness to such prices and therefore measures of a firm's flexibility for changing consumption patterns. Discussion below will include speculations based on the estimated elasticities.

4.2.1 Elasticity of Substitution

The (Morishima) elasticity of substitution measures a change of relative demand for two electricity commodities with respect to a change of their relative price. The long run elasticity here is implied by the model structure. The converging of short to long run elasticities of substitution shows that customers probably adjust their electricity consumption pattern gradually with respect to a change of relative price (see Table 7). Nevertheless, most of the adjustment occurs within six months.

Industry elasticities in Table 7 are weighted average elasticities where customers' elasticities are weighted according to their energy consumption and Leontief customers are assigned zero elasticities.

Shifting from the Mining, Paper and Allied, Non-Metallic Mineral and Chemical and Chemical Products industries may be little since their elasticities of substitution are very small. Some shifting can be expected from the Mining and Primary Textile industries according to their elasticities of substitution. With high elasticities of substitution, strong shifting may occur for those direct customers in the Rubber and Fabricated Metal Products industries.

4.2.2 Own-Price Elasticity

The (Allen) own-price elasticity measures a change in electricity demand due to a change in its own-price. Again, the converging of short to long run elasticity demonstrates that customers adjust their electricity consumption pattern gradually with respect to a change in electricity price (see Table 8). Industry elasticities are weighted average elasticities and Leontief customers are assigned zero elasticities.

Labour costs usually represent one of the largest input costs of production, and energy savings incurred from shifting may not be enough to offset the increase in labour cost, not to mention other potential labour issues which may arise. Therefore, peak elasticities, the smallest among the three groups of electricity commodity, confirm that customers are inflexible in shifting demand away from the peak period. On the other hand, relatively larger elasticities for demand charges show a lot of reaction to the de-emphasis of demand charge under the TOU rate structure.

The small own-price elasticities for peak and off-peak energy in the Mining, Primary Textile, Paper and Allied, Non-Metallic Mineral, Refined Petroleum & Coal, and Chemical & Chemical Products Industries suggest that little shifting could be expected from these industries. However, direct customers with large own-price elasticities in the Rubber and Fabricated Metal Products industries may exhibit some shiftings.

TABLE 7
MORISHIMA ELASTICITY OF SUBSTITUTION
EVALUATED AT JANUARY 1991

Percentage Change in (Peak Energy/Off-Peak Energy)/
Percentage Change in (Off-Peak Energy Price/Peak Energy Price)

SIC	INDUSTRY	CUSTOMERS STUDIED	1-MONTH	6-MONTH	LONG RUN
6	Mining	23	0.319	0.100	0.107
18	Primary Textile	2	0.145	0.145	0.145
27	Paper & Allied	24	0.061	0.074	0.074
35	Non-Metallic Mineral	4	3.830	0.051	0.050
36	Refined Petroleum and Coal	5	0.000	0.000	0.000
37	Chemical & Chemical Products	17	0.010	0.027	0.027
OTHERS					
10	Food	1	0.000	0.000	0.000
15	Rubber	1	0.223	0.893	1.000
25	Wood	1	0.000	0.000	0.000
29	Primary Metal	8	0.036	0.116	0.120
30	Fabricated Metal Products	1	0.273	0.565	0.566
32	Transportation Equipment	4	0.000	0.000	0.000
33	Electrical and Electronic	1	0.001	0.012	0.012
49	Other Utility	2	0.101	0.512	0.515
81	Federal Government Service	3	-0.011	0.110	0.363
	TOTAL	106	0.339	0.078	0.083

Source: Energy Economics Section, Economics & Forecasts Division

TABLE 8
ALLEN OWN-PRICE ELASTICITY
EVALUATED AT DECEMBER 1991

SIC	INDUSTRY	CUSTOMERS STUDIED	1-MONTH	6-MONTH	LONG RUN
			PEAK ENERGY		
6	Mining	23	-0.072	-0.050	-0.053
18	Primary Textile	2	-0.044	-0.043	-0.043
27	Paper & Allied	24	-0.045	-0.051	-0.053
35	Non-Metallic Mineral	4	-1.386	-0.021	-0.021
36	Refined Petroleum and Coal	5	0.000	0.000	0.000
37	Chemical & Chemical Products	17	-0.003	-0.009	-0.009
OTHERS					
10	Food	1	0.000	0.000	0.000
15	Rubber	1	-0.258	-1.525	-3.523
25	Wood	1	0.000	0.000	0.000
29	Primary Metal	8	-0.022	-0.035	-0.037
30	Fabricated Metal Products	1	-0.123	-0.252	-0.252
32	Transportation Equipment	4	0.000	0.000	0.000
33	Electrical and Electronic	1	-0.001	-0.009	-0.009
49	Other Utility	2	-0.042	-0.221	-0.221
81	Federal Government Service	3	-0.014	-0.051	-0.128
	TOTAL	106	-0.120	-0.043	-0.050
			OFF-PEAK ENERGY		
6	Mining	23	-0.191	-0.087	-0.093
18	Primary Textile	2	-0.104	-0.105	-0.105
27	Paper & Allied	24	-0.054	-0.058	-0.059
35	Non-Metallic Mineral	4	-2.726	-0.035	-0.034
36	Refined Petroleum and Coal	5	0.000	0.000	0.000
37	Chemical & Chemical Products	17	-0.007	-0.018	-0.018
OTHERS					
10	Food	1	0.000	0.000	0.000
15	Rubber	1	-0.253	-1.458	-2.966
25	Wood	1	0.000	0.000	0.000
29	Primary Metal	8	-0.028	-0.091	-0.094
30	Fabricated Metal Products	1	-0.170	-0.359	-0.360
32	Transportation Equipment	4	0.000	0.000	0.000
33	Electrical and Electronic	1	-0.215	-0.930	-0.931
49	Other Utility	2	-0.063	-0.310	-0.312
81	Federal Government Service	3	-0.000	-0.093	-0.289
	TOTAL	106	-0.237	-0.065	-0.072
			DEMAND CHARGE		
6	Mining	23	-0.255	-0.120	-0.127
18	Primary Textile	2	-0.143	-0.143	-0.143
27	Paper & Allied	24	-0.710	-0.620	-0.622
35	Non-Metallic Mineral	4	-3.616	-0.046	-0.046
36	Refined Petroleum and Coal	5	0.000	0.000	0.000
37	Chemical & Chemical Products	17	-0.010	-0.027	-0.027
OTHERS					
10	Food	1	0.000	0.000	0.000
15	Rubber	1	-0.556	-3.093	-8.332
25	Wood	1	0.000	0.000	0.000
29	Primary Metal	8	-0.033	-0.105	-0.109
30	Fabricated Metal Products	1	-0.253	-0.530	-0.532
32	Transportation Equipment	4	0.000	0.000	0.000
33	Electrical and Electronic	1	-0.087	-0.395	-0.396
49	Other Utility	2	-0.095	-0.483	-0.484
81	Federal Government Service	3	0.035	-0.074	-0.309
	TOTAL	106	-0.510	-0.255	-0.273

Source: Energy Economics Section, Economics & Forecasts Division

4.3 SIMULATING THE 1991 TIME-OF-USE IMPACTS

In order to measure the TOU impacts on load, we need to know what customers would demand if they were faced with a Non-TOU price but with the same economic, seasonal and technological environment. This was accomplished by simulating the Non-TOU load, assuming the coefficients and elasticities from the estimated models, a Non-TOU price but assuming the actual economic, seasonal and technological data. In addition to finding the TOU impacts, Monte Carlo simulation procedures allowed us to calculate the statistical significance of such impacts. For example, confidence bands are generated for the Non-TOU Peak demand to test the statistical significance of the TOU impact on Peak demand. We conclude that significant TOU impact occurred only if a customer's TOU (actual) Peak demand is below the confidence band of the Non-TOU peak demand (See Figure 1 and Figures in Appendix B). Here, TOU impacts estimated are strictly due to the TOU rate reform since all other factors have been netted out already.

4.3.1 TOU impact on the 1-hr Load Factor

The 1-hr Load Factor (LF) is defined as follows:

$$\text{1-hr LF} = \frac{\text{Total Energy (Peak and Off-Peak)/Total Number of Hours}}{\text{1-hr Peak During the Peak Period}}$$

The 1-hr Load Factor measures customers' overall energy consumption relative to the 1-hr Peak Demand during the Peak period (Billing Peak Demand). It has implications for customers and local distribution systems which are sensitive to peak demand.

The deterioration of the 1-hr Load Factor among most of the direct customers illustrates a responsiveness to the drop in the relative demand charges (see Table 9). This may cause a potential threat to the local distribution system if this trend continues.

4.3.2 TOU impact on the 16-hr Load Factor

The 16-hr Load Factor is defined as follows:

$$\text{16-hr LF} = \frac{\text{Total Energy (Peak and Off-Peak)/Total Number of Hours}}{\text{Total Peak Energy/Total Number of Peak Hours}}$$

The 16-hr Load Factor measures customers' overall energy consumption relative to the peak energy consumption. It provides an indication of the split of energy consumption between the peak and off-peak periods.

Almost all of the direct customers reacted to the price differential between the peak and off-peak periods positively by increasing their 16-hr Load Factors, even though the overall impact was small (see Table 9).

Figure 1

TOU CUMULATIVE IMPACTS
Representative Customer

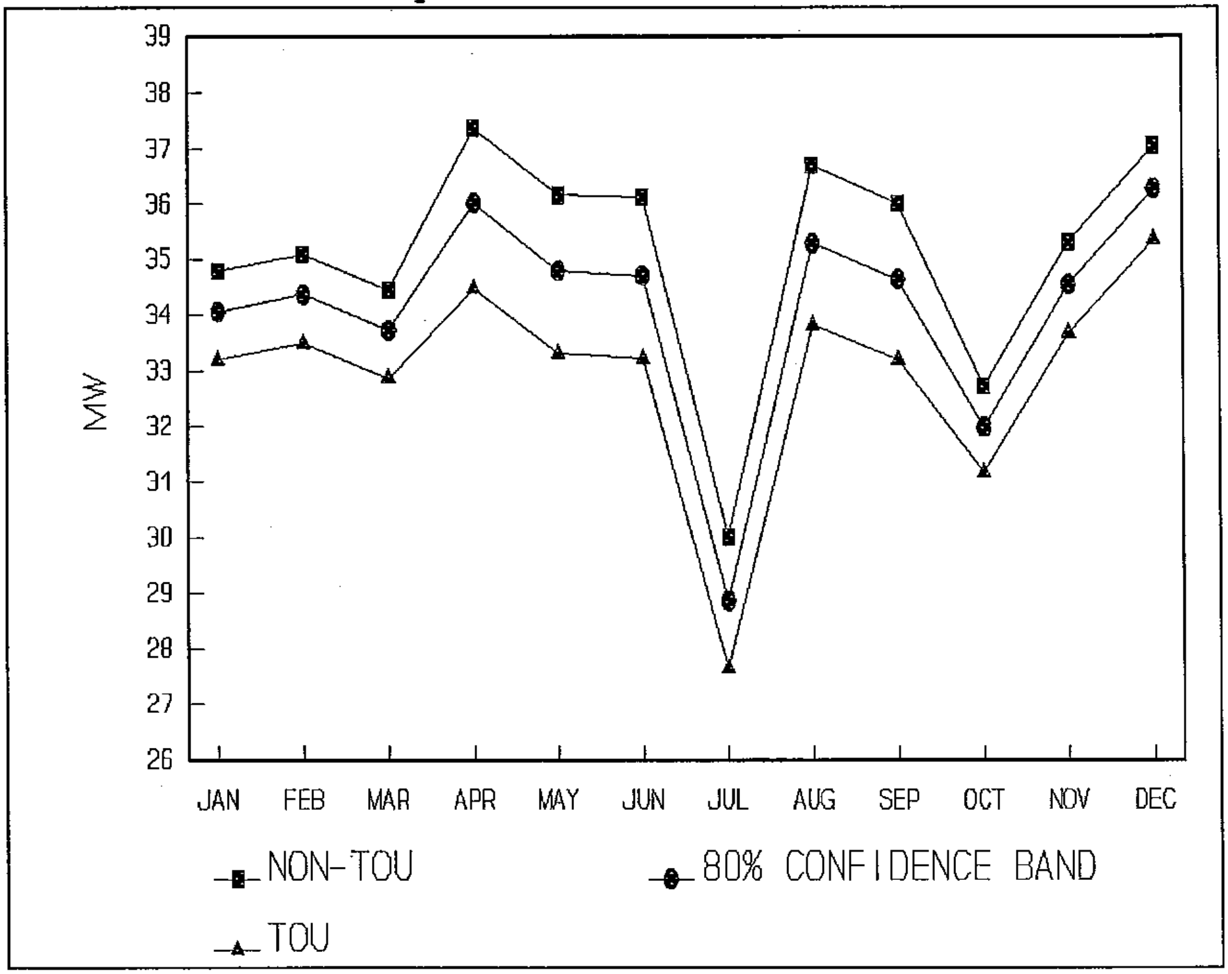

TABLE 9
TOU IMPACT ON 1-HR LOAD FACTOR

SIC	INDUSTRY	NUMBER OF CUSTOMERS	NON-TOU	TOU	DIFFERENCE
			WINTER		
6	Mining	23	0.878	0.844	-0.034
18	Primary Textile	2	0.937	0.464	-0.473
27	Paper & Allied	24	0.934	0.853	-0.081
35	Non-Metallic Mineral	4	0.855	0.843	-0.013
36	Refined Petroleum and Coal	5	0.922	0.922	0.000
37	Chemical & Chemical Products	17	1.046	1.053	0.007
OTHERS					
10	Food	1	0.430	0.430	0.000
15	Rubber	1	0.964	0.652	-0.313
25	Wood	1	0.515	0.268	-0.247
29	Primary Metal	8	0.725	0.713	-0.012
30	Fabricated Metal Products	1	0.871	0.826	-0.045
32	Transportation Equipment	4	0.664	0.661	-0.003
33	Electrical and Electronic	1	0.807	0.755	-0.052
49	Other Utility	2	1.052	0.992	-0.060
81	Federal Government Service	3	0.716	0.699	-0.018
	TOTAL	106	0.894	0.854	-0.039
			SUMMER		
6	Mining	23	0.864	0.839	-0.025
18	Primary Textile	2	0.873	0.859	-0.014
27	Paper & Allied	24	1.062	0.879	-0.183
35	Non-Metallic Mineral	4	0.847	0.837	-0.010
36	Refined Petroleum and Coal	5	0.923	0.923	0.000
37	Chemical & Chemical Products	17	0.986	0.981	-0.005
OTHERS					
10	Food	1	0.892	0.892	0.000
15	Rubber	1	1.316	0.619	-0.697
25	Wood	1	0.525	0.525	0.000
29	Primary Metal	8	0.715	0.690	-0.024
30	Fabricated Metal Products	1	1.031	0.856	-0.174
32	Transportation Equipment	4	0.671	0.671	0.000
33	Electrical and Electronic	1	0.697	0.769	0.073
49	Other Utility	2	0.853	0.828	-0.025
81	Federal Government Service	3	0.707	0.684	-0.024
	TOTAL	106	0.927	0.856	-0.071
			ANNUAL AVERAGE		
6	Mining	23	0.871	0.841	-0.029
18	Primary Textile	2	0.905	0.661	-0.243
27	Paper & Allied	24	0.998	0.866	-0.132
35	Non-Metallic Mineral	4	0.851	0.840	-0.011
36	Refined Petroleum and Coal	5	0.923	0.923	0.000
37	Chemical & Chemical Products	17	1.016	1.017	0.001
OTHERS					
10	Food	1	0.661	0.661	0.000
15	Rubber	1	1.140	0.635	-0.505
25	Wood	1	0.520	0.396	-0.124
29	Primary Metal	8	0.720	0.702	-0.018
30	Fabricated Metal Products	1	0.951	0.841	-0.110
32	Transportation Equipment	4	0.668	0.666	-0.002
33	Electrical and Electronic	1	0.752	0.762	0.010
49	Other Utility	2	0.952	0.910	-0.043
81	Federal Government Service	3	0.712	0.691	-0.021
	TOTAL	106	0.910	0.855	-0.055

Source: Energy Economics Section, Economics & Forecasts Division

TABLE 9
TOU IMPACT ON 16-HR LOAD FACTOR

SIC	INDUSTRY	NUMBER OF CUSTOMERS	NON-TOU	TOU	DIFFERENCE
			WINTER		
6	Mining	23	0.975	0.986	0.012
18	Primary Textile	2	0.973	0.985	0.013
27	Paper & Allied	24	1.023	1.034	0.011
35	Non-Metallic Mineral	4	1.168	1.174	0.006
36	Refined Petroleum and Coal	5	0.994	0.994	0.000
37	Chemical & Chemical Products	17	1.211	1.226	0.015
OTHERS					
10	Food	1	0.977	0.977	0.000
15	Rubber	1	0.968	0.962	-0.007
25	Wood	1	0.739	0.741	0.002
29	Primary Metal	8	0.963	0.974	0.011
30	Fabricated Metal Products	1	1.038	1.102	0.064
32	Transportation Equipment	4	0.805	0.809	0.004
33	Electrical and Electronic	1	0.891	0.874	-0.017
49	Other Utility	2	1.044	1.140	0.096
81	Federal Government Service	3	0.884	0.898	0.015
	TOTAL	106	1.023	1.034	0.011
			SUMMER		
6	Mining	23	0.963	0.984	0.022
18	Primary Textile	2	0.958	0.979	0.021
27	Paper & Allied	24	1.015	1.034	0.018
35	Non-Metallic Mineral	4	1.119	1.129	0.010
36	Refined Petroleum and Coal	5	0.995	0.995	0.000
37	Chemical & Chemical Products	17	1.143	1.151	0.007
OTHERS					
10	Food	1	0.996	0.996	0.000
15	Rubber	1	1.331	0.946	-0.385
25	Wood	1	0.723	0.723	0.000
29	Primary Metal	8	0.954	0.964	0.010
30	Fabricated Metal Products	1	1.056	1.163	0.106
32	Transportation Equipment	4	0.810	0.810	0.000
33	Electrical and Electronic	1	0.790	0.872	0.083
49	Other Utility	2	1.077	1.399	0.320
81	Federal Government Service	3	0.864	0.887	0.022
	TOTAL	106	1.007	1.023	0.015
			ANNUAL AVERAGE		
6	Mining	23	0.969	0.985	0.017
18	Primary Textile	2	0.965	0.982	0.017
27	Paper & Allied	24	1.019	1.034	0.015
35	Non-Metallic Mineral	4	1.144	1.152	0.008
36	Refined Petroleum and Coal	5	0.994	0.994	0.000
37	Chemical & Chemical Products	17	1.177	1.188	0.011
OTHERS					
10	Food	1	0.986	0.986	0.000
15	Rubber	1	1.150	0.954	-0.196
25	Wood	1	0.731	0.732	0.001
29	Primary Metal	8	0.959	0.969	0.011
30	Fabricated Metal Products	1	1.047	1.132	0.085
32	Transportation Equipment	4	0.808	0.810	0.002
33	Electrical and Electronic	1	0.840	0.873	0.033
49	Other Utility	2	1.060	1.268	0.208
81	Federal Government Service	3	0.874	0.892	0.019
	TOTAL	106	1.015	1.029	0.013

Source: Energy Economics Section, Economics & Forecasts Division

4.3.3 TOU impact on Peak and Off-Peak Energy Consumption

The simulated TOU impacts can be broken down into two types:

- The impact from the two-equation model (except Leontief customers which have no TOU impact from the two-equation model); i.e., the shifting between the peak and off-peak periods;
- The impact from the Aggregate Electricity Demand model (only if the relative energy price variables are found to be statistically significant); i.e., the overall reduction in energy consumption due to changes in relative energy prices.

However, the Aggregate Electricity Demand model cannot distinguish whether the TOU impact is a result of conservation or fuel switching activities. Overall, the reported TOU impacts can come from the two-equation model, the Aggregate Electricity Demand model, or both.

The 22 Leontief customers, who responded to changes in relative energy prices alone, contributed about a 10.7 mw December peak reduction due to TOU (this represents about 27% of the total December TOU impact). There were also 7 other customers whose TOU impacts were from the two-equation model as well as the Aggregate Electricity Demand model. Therefore, both sources of the TOU impacts are important.

When there is a price differential between any two periods, a shifting in load from a higher priced period to a lower priced period is usually expected. In other words, there will be a reduction in load in a higher priced period with an increase in load in a lower priced period. There are two types of shifting: in-season shifting and seasonal shifting. An in-season shifting refers to a shifting within a season (eg. summer) while a seasonal shifting is a shifting in total energy consumption from one season to another (eg. winter to summer). An unbalanced shifting happens when an energy reduction in one period is not equal to an energy increase in the other period. All customers had unbalanced shifting.

Reductions in average monthly peak energy consumption were found in almost all direct customers during the winter (see Table 10). The exceptions were the direct customers from the Refined Petroleum & Coal and Food industries. It was not a surprise because these customers did not respond to either price differentials under the TOU rate structure (i.e. Leontief models) or changes in relative energy prices (i.e. Aggregate Electricity Demand models).

Examples for in-season shifting were the Primary Textile, Paper & Allied, and Chemical & Chemical Products industries. Since the Mining and Non-Metallic Mineral industries reduced peak, off-peak and total consumption during the winter period, this reflected customers' positive response to the winter peak price increase and established the ground for a seasonal shifting.

During the summer, although industries such as the Primary Textile, Paper & Allied, and Chemical & Chemical Products industries continued to have in-season shifting, the Mining and Non-Metallic Mineral industries increased both their peak and off-peak energy consumption. As mentioned earlier, the Mining and Non-Metallic

Mineral industries responded to the seasonal price differential of the TOU rate by having seasonal shifting.

Direct customers in other industries were also divided into in-season and seasonal shifters. As a whole, direct customers reduced both peak and off-peak energy consumption during winter and achieved an in-season shifting during summer. As a result, the average monthly winter total energy consumption was reduced by 15,130 mwh (or 0.99%) while the average monthly summer total energy consumption was increased by 12,951 mwh (or 0.87%). This translated to an annual average monthly reduction of 1,089 mwh (or 0.07%).

The increase (decrease) in total energy consumption for a customer may imply that its total electricity bill has decreased (increased) relative to a Non-TOU price system. As a result, there would be a positive (negative) income effect if electricity prices are dropping (rising) relative to customers' industry prices and natural gas price. For individual direct customers, the changes in total energy consumption are mixed.

4.3.4 TOU impact on the 1992 December 16-hour Peak

Since Ontario Hydro's "official" 16-hour peak usually happens in December, it is essential to know the TOU impact on the December 16-hour Peak. There are two types of TOU impact: cumulative and net.

4.3.4.1 Cumulative TOU Impact

The cumulative TOU impact is defined as the total change in peak demand due to the TOU rate since the beginning of implementation. The cumulative TOU impact in each year is estimated using all the information available upto that year. As Table 11 indicates, the 1991 and 1992 cumulative TOU impacts were 45.82 mw and 39.35 mw peak reduction respectively. They corresponded to 2.41% and 2.06% reduction of the total December Peak demand from all direct customers.

At the industry level, the largest MW reduction contributor was the Mining industry with a -18.88 mw cumulative shifting. It was followed by the Paper & Allied industry with a -7.09 mw cumulative shifting. However, these reductions represented less than 4% of the total Peak demand in their industries.

On a customer basis, direct customers in the Rubber and Wood industries achieved some big percentage reductions (-32% and -27% respectively) in peak. Direct customers in the Primary Metal and the Transportation Equipment industries also reduced peak by more than 2 mw each.

4.3.4.2 Net TOU Impact

The net TOU impact can be defined as the difference between the estimated cumulative TOU impacts of two consecutive years. However, the net TOU impact can also be defined as the sum of incremental shiftings and reversals. Incremental shiftings refer to increases in shiftings while reversals imply reductions in shiftings. On an individual customer basis, only one of these activities will occur. At the industry level, both events can take place. A negative net impact means an incremental shifting while a positive net impact implies a reduction in shifting.

The 1992 net TOU impact was 6.47 mw. It was the difference between 1992 and 1991 cumulative impacts (i.e., 6.47 mw = -45.82 mw - (-39.35 mw)). It was also the sum of the total shiftings (-20.96 mw) and the total reversals (27.43 mw).

4.3.4.2.1 1992 Incremental Shiftings

The highest incremental (9.26 mw) came from the Mining industry. It looked like the drop in shipments (a proxy for production) for some direct customers in this industry allowed them to convince workers to shift production to the off-peak period. The second largest (4.20 mw) incremental shifting came from the Paper & Allied industry.

4.3.4.2.2 1992 Reversals

Although shiftings appeared in the Mining and Paper & Allied industries, they also had reversals. Furthermore, the reversal in the Paper & Allied industry was the largest (15.04 mw). With the increase in shipments, some direct customers in this industry might find that the flexibility to shift was reduced and production during the peak period became necessary. Similar situations might apply to the Non-Metallic Mineral and Chemical & Chemical Products industries where large reversals (over 2 mw) occurred.

4.3.4.2.3 1992 Net TOU Impacts

At the industry level, only the Mining industry came out with a -7.77 mw net TOU impact. The incremental shiftings in the Paper & Allied, Non-Metallic Mineral and Chemical & Chemical Products industries were all surpassed by their reversals such that their cumulative impacts had been reduced. So when the second largest incremental shifting paired with the largest reversal, the outcome was that the Paper & Allied industry had the largest positive net TOU impact of 10.84 mw.

For the remaining direct customers from other industries, the net TOU impacts were mixed and small. As a whole, the direct customers ended up with a 6.47 mw net TOU impact for 1992 (or a 6.47 mw reduction in cumulative shifting).

5.0 Concluding Remarks

The report provides an up-date of the econometric analysis of large direct customers' responses to the Time-of-Use rate structures. The methodology provides an estimate of the net impact while controlling for economic activity.

Given the state of the economy in 1992, Time-Of-Use rates contributed to a reduction of 39.35 MW on the December peak - a 2.06% reduction. In the winter, there was a 13,1240 Mwh (1.89%) average monthly reduction in the peak period and an overall average monthly reduction of 15,130 Mwh (0.99%). In the summer, there was an average monthly reduction of 7,585 Mwh (1.10%) in the peak but an overall average monthly increase of 12,951 Mwh (0.87%). Over the whole year, there was an average monthly reduction of 10,351 Mwh (1.49%) in the peak period and an average monthly increase of 9,368 Mwh (1.15%) in the off-peak period. All these gave an annual average monthly reduction of 1,089 mwh (0.07%) for the year.

At the industry level, the Mining industry was the biggest contributor to the cumulative and net mw reduction (-18.88 mw and -7.77 mw respectively). On the other hand, although the Paper & Allied industry was the second largest contributor to the cumulative mw reduction (-4.20 mw), it also suffered from the largest loss of cumulative shifting (-10.84 mw).

Direct customers in the other industries appeared to respond well to the TOU rate in 1992 by increasing their cumulative shifting. Exceptions were the Primary Metal and Fabricated Metal Products industries which lost some of their cumulative shifting.

The measurement of the overall conservation effect (through the aggregate demand equation) needs refining. Further analysis could be undertaken using pooled or cross-sectional analysis at the industry or firm level.

The estimated elasticities are drawn from a period (1985-1992) where there was at most one business cycle. To help refine some of the elasticity estimates, it may be worthwhile to draw upon some of the historical data for the firms with data back to 1981 which include the last recession. (This data is available for about fifty firms.)

In this paper, we quantified the impacts, given the economy in 1992. There are two opposite arguments about customers ability to shift during recession years. One argument suggests that more load shifting has happened as customers became more cost conscious and unions have been more cooperative. The converse argument is that customers production has been reduced so much that customers load shifting has been cut down or at best maintained at the same level. The models can be used to simulate the impact of TOU rates under different economic scenarios.

The direct customers' Time-Of-Use price differentials continue to change until 1992 - at which time they are frozen for 10 years. The analysis of TOU impacts in 1992 and thereafter will help us answer whether the methodology and results are stabilizing. Certainly, the issue of short run versus long run impacts will be better addressed.

TABLE 10
TOU IMPACT ON
PEAK AND OFF-PEAK ENERGY CONSUMPTION
AVERAGE MONTHLY MWH

SIC	INDUSTRY	NUMBER OF CUSTOMERS	OFF-PEAK	PEAK	TOTAL	PERCENTAGE REDUCTION OFF-PEAK	PEAK	TOTAL
		WINTER						
6	Mining	23	-6089	-2466	-8647	-3.58	-1.28	-2.38
18	Primary Textile	2	-90	10	-80	-1.92	0.19	-0.80
27	Paper & Allied	24	-2881	812	-2059	-1.41	0.32	-0.45
35	Non-Metallic Mineral	4	-638	-704	-1345	-1.50	-1.20	-1.33
36	Refined Petroleum and Coal	5	0	0	0	0	0	0
37	Chemical & Chemical Products	17	-463	231	-235	-0.55	0.20	-0.12
OTHERS								
10	Food	1	0	0	0	0	0	0
15	Rubber	1	-557	-77	-630	-25.17	-4.13	-15.47
25	Wood	1	-381	-234	-614	-23.89	-24.62	-24.13
29	Primary Metal	8	-851	904	47	-1.45	1.50	0.04
30	Fabricated Metal Products	1	-308	-201	-508	-2.76	-1.18	-1.80
32	Transportation Equipment	4	-565	-524	-1096	-1.64	-1.97	-1.79
33	Electrical and Electronic	1	-117	161	41	-5.64	9.90	1.11
49	Other Utility	2	-38	82	42	-1.86	3.12	0.92
81	Federal Government Service	3	-146	101	-46	-2.46	1.95	-0.41
	TOTAL	106	-13124	-1905	-15130	-1.89	-0.23	-0.99
		SUMMER						
6	Mining	23	682	9589	10266	0.40	5.07	2.84
18	Primary Textile	2	-22	212	189	-0.48	4.22	1.97
27	Paper & Allied	24	-5155	3176	-1441	-2.51	1.50	-0.32
35	Non-Metallic Mineral	4	343	1558	1900	0.90	3.02	2.11
36	Refined Petroleum and Coal	5	0	0	0	0	0	0
37	Chemical & Chemical Products	17	-1470	1680	211	-1.82	1.52	0.11
OTHERS								
10	Food	1	0	0	0	0	0	0
15	Rubber	1	-925	47	-936	-36.35	2.74	-21.66
25	Wood	1	217	128	345	21.64	21.04	21.41
29	Primary Metal	8	-1024	2078	1017	-1.71	3.43	0.84
30	Fabricated Metal Products	1	140	98	238	1.29	0.61	0.88
32	Transportation Equipment	4	351	629	982	1.07	2.53	1.70
33	Electrical and Electronic	1	-190	350	175	-9.04	25.27	5.04
49	Other Utility	2	-295	362	52	-14.17	17.33	1.24
81	Federal Government Service	3	-237	192	-47	-3.91	3.77	-0.42
	TOTAL	106	-7585	20639	12951	-1.10	2.58	0.87
		ANNUAL AVERAGE						
6	Mining	23	-2703	3562	810	-1.58	1.87	0.22
18	Primary Textile	2	-55	111	54	-1.19	2.16	0.55
27	Paper & Allied	24	-4016	2265	-1750	-1.96	0.90	-0.38
35	Non-Metallic Mineral	4	-148	426	278	-0.37	0.77	0.29
36	Refined Petroleum and Coal	5	0	0	0	0	0	0
37	Chemical & Chemical Products	17	-967	956	-13	-1.18	0.85	-0.01
OTHERS								
10	Food	1	0	0	0	0	0	0
15	Rubber	1	-741	-15	-738	-31.15	-0.84	-18.66
25	Wood	1	-82	-53	-134	21.64	21.04	21.41
29	Primary Metal	8	-937	1491	533	-1.58	2.46	0.44
30	Fabricated Metal Products	1	-84	-51	-135	-0.76	-0.31	-0.49
32	Transportation Equipment	4	-107	52	-57	-0.32	0.20	-0.10
33	Electrical and Electronic	1	-154	255	108	-7.38	16.93	3.01
49	Other Utility	2	-166	222	47	-8.29	9.41	1.08
81	Federal Government Service	3	-191	147	-47	-3.19	2.86	-0.42
	TOTAL	106	-10351	9368	-1089	-1.49	1.15	-0.07

TABLE 11
TOU IMPACT
ON DECEMBER 16-HOUR PEAK

			1991 DECEMBER			1992 DECEMBER			1992 DECEMBER
			TOTAL	TOU IMPACT		TOTAL	TOU IMPACT		NET TOU
SIC	INDUSTRY	CUSTOMERS STUDIED	DEMAND MW	MW RED.	% RED.	DEMAND MW	MW RED.	% RED.	IMPACT MW
6	Mining	23	592	-11.11	-1.88	533	-18.88	-3.54	-7.77
18	Primary Textile	2	8	-0.56	-7.00	6	-0.23	-3.71	0.33
27	Paper & Allied	24	438	-17.93	-4.09	530	-7.09	-1.34	10.84
35	Non-Metallic Mineral	4	113	-5.55	-4.91	106	-2.59	-2.45	2.96
36	Refined Petroleum and Coal	5	196	-1.44	-0.73	204	0.00	0.00	1.44
37	Chemical & Chemical Products	17	250	-3.03	-1.21	197	-0.52	-0.26	2.51
OTHERS									
10	Food	1	9	0.00	0.00	10	0.00	0.00	0.00
15	Rubber	1	4	0.00	0.00	5	-1.56	-31.77	-1.56
25	Wood	1	2	0.00	0.00	4	-1.04	-27.30	-1.04
29	Primary Metal	8	151	-2.57	-1.70	157	-2.37	-1.51	0.20
30	Fabricated Metal Products	1	32	-2.51	-7.84	33	-1.70	-5.08	0.81
32	Transportation Equipment	4	92	-0.99	-1.08	98	-2.47	-2.52	-1.48
33	Electrical and Electronic	1	4	0.00	0.00	5	-0.30	-6.07	-0.30
49	Other Utility	2	5	0.00	0.00	5	-0.11	-2.31	-0.11
81	Federal Government Service	3	8	-0.13	-1.63	17	-0.49	-2.96	-0.36
	TOTAL	106	1904	-45.82	-2.41	1908	-39.35	-2.06	6.47

Seasonal →

TABLE 12
SHIFTING AND REVERSAL
ON DECEMBER 16-HOUR PEAK

1992 DECEMBER

SIC	INDUSTRY	CUSTOMERS STUDIED	INCREMENTAL SHIFTING MW	REVERSAL MW	NET IMPACT MW
6	Mining	23	-9.26	1.49	-7.77
18	Primary Textile	2	0.00	0.00	0.00
27	Paper & Allied	24	-4.20	15.04	10.84
35	Non-Metallic Mineral	4	-1.13	4.09	2.96
36	Refined Petroleum and Coal	5	0.00	1.44	1.44
37	Chemical & Chemical Products	17	-0.35	2.86	2.51
OTHERS					
10	Food	1	0.00	0.00	0.00
15	Rubber	1	-1.56	0.00	-1.56
25	Wood	1	-1.04	0.00	-1.04
29	Primary Metal	8	-1.15	1.35	0.20
30	Fabricated Metal Products	1	0.00	0.81	0.81
32	Transportation Equipment	4	-1.50	0.02	-1.48
33	Electrical and Electronic	1	-0.30	0.00	-0.30
49	Other Utility	2	-0.11	0.00	-0.11
81	Federal Government Service	3	-0.36	0.00	-0.36
	TOTAL	106	-20.96	27.43	6.47

REFERENCES

Judge, G. G., W. E. Griffiths, R. Carter Hill, H. Lutkepohl and T. C. Lee, (1985), The Theory of Practice of Econometrics (Wily, second edition).

Mountain, D. and Hsiao, C. (1989), "A Combined Structural and Flexible Functional Approach for Modelling Energy Substitution." Journal of the American Statistical Association, volume 84, No. 405, Applications and Case Studies.

Mountain, D. and Zhu, J. (1991), "Time-of-Use Impacts on Ontario Hydro's Direct Industrial Customers, Econometric Methodology." Ontario Hydro.

Association of Major Power Consumers of Ontario (AMPCO) INTERROGATORY #57 List 1

Interrogatory

8.1 Is it appropriate to implement "AMPCO's High 5 Proposal" in place of the status quo charge determinants for Network service?

Ref: Ex H1/Tab 3/Schedule 1/Attachment 1/Page 41/ Section 3.2.5

The Consultant states, "The Cheng and Mountain results are the best available empirical estimates of substitution elasticities in Ontario".

Please provide the criteria by which the results obtained in this study are judged to be the best estimates available.

Response

This response is provided by Power Advisory.

This study applied appropriate econometric techniques to individual customer billing data to produce estimates of elasticities of substitution. No other study could have access to the same data, since this one was done within Ontario Hydro. An extensive search, a review of an extensive bibliography of electricity elasticity studies, and discussions with several elasticity experts did not disclose any studies with better estimates of elasticities of substitution for Ontario industries.

Association of Major Power Consumers of Ontario (AMPCO) INTERROGATORY #58
List 1

Interrogatory

8.1 Is it appropriate to implement "AMPCO's High 5 Proposal" in place of the status quo charge determinants for Network service?

Ref: Ex H1/Tab 3/Schedule 1/Attachment 1/Page 41/ Section 3.2.5

The report says, "They may therefore overstate the current customers' reaction to changes in prices because there is less scope for shifting that at the time of their estimation."

Please provide analysis, including assumptions, data sets and calculations, to substantiate the statement that "there is less scope" for shifting now than in 1993.

Response

This response is provided by Power Advisory.

There is less scope for shifting given the availability of demand response programs as well as the use of real time pricing where electricity supply costs to customers change from hour to hour. This is evident from the hourly demand data presented by AMPCO which shows significant loading shifting from peak to off-peak periods. (Pre-filed evidence submitted by AMPCO in EB-2008-0272, p. 5)

Association of Major Power Consumers of Ontario (AMPCO) INTERROGATORY #59 List 1

Interrogatory

8.1 Is it appropriate to implement "AMPCO's High 5 Proposal" in place of the status quo charge determinants for Network service?

Ref: Ex H1/Tab 3/Schedule 1/Attachment 1/Page 41/ Section 3.2.5/Table 10

In Table 1, the Consultant applies an elasticity of 0.02 in the high case.

Please explain the rationale to apply an elasticity for industries for which no statistical evidence of elasticity was found.

Response

This response is provided by Power Advisory.

The evidence found was not sufficient to reject the null hypothesis that the elasticity is zero. As part of a case where all elasticities are higher than the available estimates, Power Advisory applied a small elasticity to this industry.

<u>Association of Major Power Consumers of Ontario (AMPCO) INTERROGATORY #60 List 1</u>

Interrogatory

8.1 Is it appropriate to implement "AMPCO's High 5 Proposal" in place of the status quo charge determinants for Network service?

Ref: Ex H1/Tab 3/Schedule 1/Attachment 1/Page 50/ Section 3.3/Table 12

Please provide the formulas used to calculate load shifts.

Response

This response is provided by Power Advisory.

Please see Exhibit I, Tab 4, Schedule 68, part f.

<u>Association of Major Power Consumers of Ontario (AMPCO) INTERROGATORY #61 List 1</u>

Interrogatory

8.1 Is it appropriate to implement "AMPCO's High 5 Proposal" in place of the status quo charge determinants for Network service?

Ref: Ex H1/Tab 3/Schedule 1/Attachment 1/Page 50/ Section 3.3/Footnote 121

Please provide the details of the finding that explains the Consultant's conclusion that AMPCO appears to have misapplied the elasticity formula.

Response

This response is provided by Power Advisory.

<u>Correct definition and application of own-price elasticity</u>

Own-price elasticity is given here by the symbol η:

$\eta = dq/dp \times p/q$, where p and q are the original price and quantity and dq/dp is the first derivative of the demand curve at the point where elasticity is being evaluated.

In finite terms, as a % formula, it is
$\eta = \Delta q/q \div \Delta p/p$.[1]

Therefore, by simple rearrangement, we get
$\Delta q = \eta \times \Delta p/p \times q$.

<u>AMPCO application in Undertaking J6.3 (EB-2008-0272)</u>

The clearest statement by AMPCO of the formulas it used is in Undertaking J6.3. Using the formulas in Undertaking J6.3, the AMPCO formula for Δq is

$\Delta q = (\eta \times (p+ \Delta p)/p \times q \times q/p)/100$.

[1] This can be read as the % change in quantity/ % change in price. See, for example, EPRI, Price Elasticity of Demand for Electricity: A Primer and Synthesis, Jan/. 2008, pg. 16.

This formula has $(p+ \Delta p)/p$ instead of $\Delta p/p$, an extra term of q/p, and an extra division by 100.

Association of Major Power Consumers of Ontario (AMPCO) INTERROGATORY #62 List 1

Interrogatory

8.1 Is it appropriate to implement "AMPCO's High 5 Proposal" in place of the status quo charge determinants for Network service?

Ref: Ex H1/Tab 3/Schedule 1/Attachment 1/Page 58/ Section 5/Footnote 131

A) Please explain whether, in the Consultant's opinion, the "commodity cost" includes the Global Adjustment.

B) Please explain why the Consultant did not calculate the effect on the Global Adjustment of a reduction in HOEP.

Response

The response to parts A and B are provided by Power Advisory.

A) The commodity cost is meant to refer to the HOEP and thus doesn't include the Global Adjustment.

B) This was beyond the scope of the analysis requested by Hydro One in its RFP. However, Power Advisory expects that the increases in the Global Adjustment would offset a significant proportion of the commodity cost savings realized by consumers. Specifically, while implementation of the High 5 proposal may cause HOEP to decrease, Power Advisory believes that a significant portion of this decrease would be offset by increases in the Global Adjustment.

Association of Major Power Consumers of Ontario (AMPCO) INTERROGATORY #63 List 1

Interrogatory

8.1 Is it appropriate to implement "AMPCO's High 5 Proposal" in place of the status quo charge determinants for Network service?

Ref: Ex H1/Tab 3/Schedule 1/Attachment 1/Page 59/Section 5.1/Figure 4

A) How did Power Advisory construct the Ontario Electricity Supply Curve shown in Figure 4?

B) Please reproduce figure 4 based on actual generation capacity and unit costs for Ontario.

Response

The response to parts A and B are provided by Power Advisory.

A) This is based on assumptions regarding Ontario generation facility capacity ratings and generation facility marginal operating costs.

B) Figure 4 provides an estimate of actual generation capacity and unit costs for Ontario.

<u>Association of Major Power Consumers of Ontario (AMPCO) INTERROGATORY #64 List 1</u>

Interrogatory

8.1 Is it appropriate to implement "AMPCO's High 5 Proposal" in place of the status quo charge determinants for Network service?

Ref: Ex H1/Tab 3/Schedule 1/Attachment 1/Page 60/ Section 5.1

The Consultant's report says, "Since gas is the fossil fuel with the highest marginal cost,"

A) Please clarify whether this sentence refers to natural gas as a fuel compared to other fossil fuels, or the variable fuel costs, or marginal costs, of fossil-fueled electricity generation.

B) In either case, please provide the data and analysis to substantiate this statement, for 2007, 2008 and 2009.

Response

The response to parts A and B are provided by Power Advisory.

A) This question is not clear to Power Advisory, but natural gas has a higher cost than other fossil fuels and as a result natural gas-fired generation is typically more expensive than other fossil-fueled generation resources..

B) Power Advisory has not developed this data set. We note, however, that the capacity factors for dispatchable natural gas-fired resources are typically among the lowest of any dispatchable generation resources.

Association of Major Power Consumers of Ontario (AMPCO) INTERROGATORY #65
List 1

Interrogatory

8.1 Is it appropriate to implement "AMPCO's High 5 Proposal" in place of the status quo charge determinants for Network service?

Ref: Ex H1/Tab 3/Schedule 1/Attachment 1/Page 60/ Section 5.2.1
Ref: Ex H1/Tab 3/Schedule 1/Attachment 1/Page 61/ Section 5.2.2

On page 60, the report states, "Dr. Sen's model cannot model price spikes." On page 61, the report states, "We have used this model to provide electricity market price forecasts for clients."

Explain the extent to which the Consultant's model models price spikes?

Response

This response is provided by Power Advisory.

The Power Advisory Model doesn't fully reflect price spikes. However, it does reflect how prices are anticipated to change based on where demand is relative to the system's supply curve. Whereas, Dr. Sen's model assumes a constant relationship between demand and price for the entire peak and off-peak periods.

Association of Major Power Consumers of Ontario (AMPCO) INTERROGATORY #66 List 1

Interrogatory

8.1 Is it appropriate to implement "AMPCO's High 5 Proposal" in place of the status quo charge determinants for Network service?

Ref: Ex H1/Tab 3/Schedule 1/Attachment 1/Page 62/Section 5.3
Ref: Ex H1/Tab 3/Schedule 1/Attachment 1/Page 63/Section 5.4/Table 16

Robust forecasting is accomplished through structural econometric or statistical models. On page 62, the Consultant discusses a forecasting model that it has constructed to forecast load shifts in 2011. On page 63, Power Advisory the total commodity cost changes are shown in Table 16.

A) Please provide a working version of the Consultant's forecasting model (or a description of the econometric equations that drive the model).

B) Please provide a copy of the data set described in Section 5.2 that was used to derive the value in Table 16.

C) Please clarify that the data in the Table 16 labelled "Commodity Cost Saving Estimates", refers only to estimated average Hourly Ontario Energy Prices.

Response

The response to parts A, B and C are provided by Power Advisory.

A) This model is proprietary and commercially sensitive. The model is described in Section 5.2.2 of the Power Advisory Report.

B) The data described in Section 5.2 in effect include all of the input data for the Power Advisory market model. As noted in part A), this model is commercially sensitive.

Its detailed inputs are an integral part of Power Advisory's efforts in preparing and maintaining the model.

Some of its assumptions are taken from publicly available data. These include the IESO's 18-month outlook (available at http://www.ieso.ca/imoweb/monthsYears/monthsAhead.asp), the OPA's quarterly Progress Reports on Electricity Supply (available at http://www.powerauthority.on.ca/Page.asp?PageID=122&ContentID=6972&SiteNodeID=120), press releases from Bruce Power (available at http://www.brucepower.com/pagecontent.aspx?navuid=12) OPG (available at http://www.opg.com/news/releases/) and other generators, and other information from the trade and general press.

C) The data presented in Table 16 is based on average Hourly Ontario Energy Prices.

Association of Major Power Consumers of Ontario (AMPCO) INTERROGATORY #67 List 1

Interrogatory

8.1 Is it appropriate to implement "AMPCO's High 5 Proposal" in place of the status quo charge determinants for Network service?

Ref: Ex H1/Tab 3/Schedule 1/Attachment 1/Page 63/ Section 5.4

Power Advisory states at the bottom of Page 63, "The average price reductions in the off-peak periods are always lower than the average price increases in the peak periods,….."

Please confirm that the words "reduction" and "increases" in this sentence should be reversed.

Response

This response is provided by Power Advisory.

That is correct, these words should be reversed.

Association of Major Power Consumers of Ontario (AMPCO) INTERROGATORY #68 List 1

Interrogatory

8.1 Is it appropriate to implement "AMPCO's High 5 Proposal" in place of the status quo charge determinants for Network service?

Ref: Ex H1/Tab 3/Schedule 1/Attachment 1/Page 72-73/ Section 5.4

The report states, "Therefore, reductions in load in on-peak periods can exacerbate congestion, rather than alleviate it."

A) Please provide specific examples where this has occurred, including supporting data or references.

B) Please provide an estimate of the congestion costs (e.g., via increases in Congestion Management Settlement Credits) incurred as a result of demand reductions during periods of peak system demand.

Response

The response to parts A and B are provided by Power Advisory.

A) This statement is based on discussions that Power Advisory staff had with Hydro One transmission planners. We don't have specific examples.

B) Power Advisory has not performed such an analysis.

<u>Association of Major Power Consumers of Ontario (AMPCO) INTERROGATORY #69 List 1</u>

Interrogatory

8.1 Is it appropriate to implement "AMPCO's High 5 Proposal" in place of the status quo charge determinants for Network service?

Ref: Ex H1/Tab 3/Schedule 1/Attachment 1/Page 76/Section 8

The Consultant's report indicates that, "For those network transmission facilities that may be deferred by demand reductions, it may be more effective and efficient to design and implement such programs to do this."

A) Please provide an example of such a program, if any exists, in other jurisdictions.

Where such a program exists, please provide estimates of costs and benefits, if any estimates are available. Please explain how the costs of such a program would be recovered from customers.

Response

This response is provided by Power Advisory.

A) Power Advisory didn't perform any research regarding such programs and has no examples it can provide.

Association of Major Power Consumers of Ontario (AMPCO) INTERROGATORY #70 List 1

Interrogatory

9.1 – Are the OM&A and capital amounts in the Green Energy Plan appropriate and based on appropriate planning criteria?

Ref: Ex A/Tab 11/Schedule 4/Appendix A/Page 1
Ref: Ex A/Tab 11/Sch 4/Page 3

The letter dated September 21, 2009 from the then Minister of Energy and Infrastructure (Appendix A) includes a number of major projects to upgrade the transmission and distribution systems in anticipation of renewable generation likely to come from the Feed-In-Tariff (FIT) program. The Minister's letter directs Hydro One to proceed with the planning, development and implementation of transmission projects outlined in the letter and to collaborate with the OPA in defining scope of work and with the IESO regarding System Impact Assessments and reliability impacts.

On page 3, the evidence states "Hydro One continues to consult collaboratively with the Ontario Power Authority ("OPA") in defining the scope of work associated with the GE projects."

A) Please provide a summary of the collaboration that has taken place between Hydro One and the OPA and the IESO since September 2009. Please include supporting documentation such as dates of meetings, directives from meetings, correspondence between parties as well as a description of how this collaboration has informed Hydro One's Green energy Plan.

B) Has the scope of work or prioritization of specific projects changed as a result of the collaboration between Hydro One and the OPA and the IESO since 2009? If yes, please describe the change and the projects affected?

C) Have any of the target in-service dates shown on Schedules A and B attached to the Minister's letter been altered as a result of this collaboration?

Response

A) B) & C) Please see Exhibit I, Tab 1, Schedule 98.

Association of Major Power Consumers of Ontario (AMPCO) INTERROGATORY #71 List 1

Interrogatory

9.1 – Are the OM&A and capital amounts in the Green Energy Plan appropriate and based on appropriate planning criteria?

Ref: Ex A/Tab 11/Schedule 4/Appendix A/Page 3

The then Minister of Energy and Infrastructure, in his letter dated September 21, 2009, indicates that Hydro One is to report back on a semi-annual basis on planning, development and implementation activities undertaken and the progress made in connection with Transmission and Distribution projects. Hydro One was asked to submit a first report by no later than the end of November 2009.

Please provide copies of all progress reports submitted to the Minister of Energy and Infrastructure in November 2009 and beyond in connection with the Transmission and Distribution projects outlined in the Minister's letter.

Response

Only one progress report was issued to the Minister from Hydro One on December 29, 2009. The report is attached as Attachment 1.

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Laura I. Formusa
President & CEO

hydro One

December 29, 2009

The Honourable Gerry Phillips
Minister of Energy and Infrastructure
4th Floor, Hearst Block
900 Bay Street
Toronto, Ontario M7A 2E1

Dear Minister:

Status Report – Transmission and Distribution Projects in Support of Renewable Energy Projects

On September 21, 2009, the former Minister of Energy and Infrastructure and Deputy Premier, George Smitherman, wrote to our Chair, James Arnett, asking Hydro One to immediately proceed with the planning, development, and implementation of transmission projects and distribution system upgrades in anticipation of the Feed-in Tariff program and the associated high demand for renewable connections. We subsequently confirmed our understanding of the letter's intent and concurred with what was asked by the Minister.

We have developed a Green Energy Implementation Plan, which provides a comprehensive framework for accomplishing the Transmission and Distribution projects outlined in the September 21st letter. The Plan includes an assessment of the necessary actions and processes associated with obtaining approvals for the transmission projects. This Plan was shared with Ministry staff in November and will continue to be updated to reflect the status of the renewable energy projects.

Eight priority transmission projects in northern and southwestern Ontario have been identified, in consultation with the OPA. The development work for seven of these projects is well underway and work on others will be initiated early in 2010. Our progress on these projects is a reflection of our expertise and commitment to the timely expansion of Hydro One's transmission and distribution networks to accommodate renewable generation.

The remaining suite of projects will be initiated once the results of the Feed-in Tariff program and the need for new transmission are confirmed by the OPA. It is important that we continuously review and re-align our plans to be consistent with the location of renewable generation applications throughout the Province.

The development work to obtain approvals involves a number of inter-related processes which most often require three years and beyond to complete. Our recent experience with major transmission projects has provided us with an extensive understanding of these existing processes and has positioned us well to undertake the projects outlined in the Minister's letter.

Our experience also shows that extensive coordination and timely actions are required from not only Hydro One but the OPA, IESO, and government ministries including the MEI, MOE and MNR, to support the need for these projects and to meet our ambitious project timelines. Furthermore, regulatory clarity is important in understanding how the OEB will test the prudence of the green transmission and distribution projects in light of its new statutory object to "promote the use and generation of electricity from renewable energy sources in a manner consistent with the policies of the Government of Ontario, which includes the timely expansion or reinforcement of transmission systems and distribution systems to accommodate the connection of renewable generation facilities". In this regard, we are working closely with all affected agencies, ministries and our regulator.

Hydro One fully understands the importance to the Province of Ontario of the *Green Energy and Green Economy Act* and the Feed-in-Tariff (FIT) Program. The projects have been given a high priority within our business plan and are fully supported at an internal working level. The unprecedented response to the FIT Program will require some re-alignment of our plans in order to ensure we are giving the right priority to our transmission and distribution projects. We are also continuing to examine and discuss potential partnership models, including partnerships with First Nation communities.

We will continue to provide regular briefings to Ministry staff. Should you require further details at any time on the activities and progress associated with the green projects, please contact me or Mike Penstone, Vice President of Major Project Coordination and External Relations at (416) 345-5444.

Sincerely,

L Formusa

Laura Formusa
President and CEO
Hydro One Inc.

cc: James Arnett, Chair, Hydro One Inc.
Saäd Rafi, Deputy Minister, Ministry of Energy and Infrastructure

Association of Major Power Consumers of Ontario (AMPCO) INTERROGATORY #72 List 1

Interrogatory

9.1 – Are the OM&A and capital amounts in the Green Energy Plan appropriate and based on appropriate planning criteria?

Ref: Ex A/Tab 11/Schedule 4/Page 2

The evidence states on page 2 that the GE Projects are required to connect new renewable generation facilities procured through the FIT program and "other means".

A) Please provide a definition of "other means".

B) What is the historical and forecasted capacity (test years and beyond) for renewable generation contracted through "other means"? How has Hydro One incorporated this capacity in its Green Energy Plan?

Response

A) "Other means" is the collection of procurement processes other than the FIT Program that contract for the development of renewable generation resources. For example, this includes the OPA's RESOP, CHP III, RES, HESA, and other programs.

B) The historical results of the OPA's non-FIT procurement programs for renewable generation resources are provided in the table below.

Resource Type	Capacity under Contract as of Q1 2010 (MW)
Bioenergy	91
Bioenergy CHP	78
Hydro	1,190
Solar	526
Wind	1,888
Total	3,773

Source: OPA's "A Progress Report on Electricity Supply First Quarter 2010"

These resources are not part of the green energy plan as they were evaluated by Hydro One through the CIA process.

Hydro One is not aware of any forecasts other than the Green Energy Investment Agreement, under a directive to the OPA from the Minister on April 1, 2010 for the development of 2,500 MW of wind and solar resources.

Association of Major Power Consumers of Ontario (AMPCO) INTERROGATORY #73 List 1

Interrogatory

9.1 – Are the OM&A and capital amounts in the Green Energy Plan appropriate and based on appropriate planning criteria?

Ref: Ex A/Tab 11/Schedule 4/Page 2

The evidence states, "While the timing and nature of some GE projects will depend on the results of the FIT program, this Plan encompasses transmission investments that will form the backbone of an electricity system re-designed to integrate up to 10,000 MW and beyond of potential renewable generation".

A) For the GE projects referenced above that depend on the results of the FIT program, please provide the latest FIT program results related to these projects.

B) What impacts do the current results have on these projects with respect to timing, spending and prioritization? What are the forecasted FIT program results related to these projects?

C) Please explain how the estimated 10,000 MW and beyond of potential renewable generation was derived.

Response

A) Please see Exhibit I, Tab 1, Schedule 101.

B) The OPA's Economic Connection Test process will assign FIT applicants to specific transmission projects. As this process is not yet underway, it is not possible to forecast FIT program results related to the GE projects at this time.

C) The estimate was based on FIT results published on the OPA website.

Association of Major Power Consumers of Ontario (AMPCO) INTERROGATORY #74 List 1

Interrogatory

9.1 – Are the OM&A and capital amounts in the Green Energy Plan appropriate and based on appropriate planning criteria?

Ref: Ex A/Tab 11/Schedule 4/page 5

The evidence states, in addition to current FIT applications under review by the OPA, many more applications are expected to be submitted in the future."

Please complete the following table to summarize the total renewable energy potential (FIT + Other Means) by green energy project in Sept 21, 2010 Minister's letter for: a) the test year period and b) for the period 2013-2016.

Renewable Energy Potential – Schedule A Projects												
Item # (by project category)	Item # as per Sch A	Investment Description	Solar Ground (MW)	Solar Roof (MW)	Wind (MW)	Wind (MW)	Water (MW)	Bio-Gas (MW)	Biomass (MW)	Landfill (MW)	Other (MW)	Total
1	1											
2	5											
3	2 & 3											
4	8											
5	4											
6	7 & 9											
7	14											
8	18											
9	10											
10	11											
11	12											
12	13											
13	15											
14	16											
15	17											
16	19											
17	6											
18	20											
Sub-total												
Renewable Energy Potential – Schedule B Projects												
Item # (as per Table 2 A/11/4)	Item # as per Sch B	Investment Description	Solar Ground (MW)	Solar Roof (MW)	Wind (MW)	Wind (MW)	Water (MW)	Bio-Gas (MW)	Biomass (MW)	Landfill (MW)	Other (MW)	Total
1												
2												
3												
4												
5												
Total												

Response

The total renewable energy potential for each of the Schedule A green energy projects cannot be determined at this time.

<u>Association of Major Power Consumers of Ontario (AMPCO) INTERROGATORY #75 List 1</u>

<u>Interrogatory</u>

9.1 – Are the OM&A and capital amounts in the Green Energy Plan appropriate and based on appropriate planning criteria?

Ref: Ex A/Tab 11/Schedule 4/Page 5

Hydro One indicates on page 5, "This will require new approaches to project prioritization to properly assess the importance of aging asset issues relative to the Green Energy projects."

Please describe the new approaches to project prioritization that Hydro One is considering.

<u>Response</u>

The statement above is a forward looking statement. As explained in Exhibit A, Tab 12, Schedules 4 & 5 Hydro One's Investment Planning and Prioritization process is designed to accommodate changing conditions and priorities and the incorporation of green energy projects will be part of that evolution of the process.

Association of Major Power Consumers of Ontario (AMPCO) INTERROGATORY #76 List 1

Interrogatory

9.1 – Are the OM&A and capital amounts in the Green Energy Plan appropriate and based on appropriate planning criteria?

Ref: Ex A/Tab 11/Schedule 4/Page 7

The evidence states, "Hydro One will need to be prepared to adopt to changes in plans brought about by the GEGEA. The FIT program is essentially a customer driven program so that project location and sizes are not predetermined."

Please explain how Hydro One plans to adapt to changes during the test period should the OPA or the government redefine the needs and scope of work associated with green energy projects based on emerging and ongoing FIT information or new policy directions that affect anticipated transmission needs.

Response

Please see Exhibit I, Tab 1, Schedule 98.

Association of Major Power Consumers of Ontario (AMPCO) INTERROGATORY #77 List 1

Interrogatory

9.1 – Are the OM&A and capital amounts in the Green Energy Plan appropriate and based on appropriate planning criteria?

Ref: Ex A/Tab 11/Schedule 4/Page 8

Hydro One indicates that the Green Energy Plan will constitute a major portion of the Transmission development Capital work program with spending of $2.5 B in the near term (2010-2014) and $4.5 B over the longer term (2015-2020) for a total of $7 B in spending.

What specific approvals is Hydro One seeking for spending that will occur beyond the 2011/2012 test years?

Response

Hydro One is not seeking approval for any spending that will occur beyond the test years.

Association of Major Power Consumers of Ontario (AMPCO) INTERROGATORY #78 List 1

Interrogatory

9.1 – Are the OM&A and capital amounts in the Green Energy Plan appropriate and based on appropriate planning criteria?

Ref: Ex A/Tab 11/Schedule 4/Section 4/Pages 10 to 18

Pages 10 to 18 briefly describe the major green energy projects in the following groupings: where development work is underway; where development work will begin once the OPA confirms project need; and where development work is not planned in the test years. Total OM&A development work and capital expenditures are provided for each project. Please complete the following table to show the total OM&A and capital costs and the test year costs by project category.

Project Category	Total OM&A	OM&A 2011 Test Year	OM&A 2012 Test Year	Total Capital	Capital 2011 Test Year	Capital 2012 Test Year
Development work is underway						
Development work will begin once the OPA confirms project need						
Development work is not planned in the test years						
Total						

Response

The OM&A development work in the test years was only planned for the projects in the first category and these costs are shown in Table 5 on page 46 of the exhibit, however as explained in Exhibit I, Tab 1, Schedule 98 this work is now on hold. Capital costs are only planned for two of the projects in the test years as shown in Table 4 on page 37.

Association of Major Power Consumers of Ontario (AMPCO) INTERROGATORY #79 List 1

Interrogatory

9.1 – Are the OM&A and capital amounts in the Green Energy Plan appropriate and based on appropriate planning criteria?

Ref: Ex A/Tab 11/Schedule 4/Page 9/Section 4/Table 1
Ref: Ex A/Tab 11/Schedule 4/Page 46/Table 5

Table 1 on page 4 (Summary of Major Green Projects) lists the projects from Schedule A of the Minister's September 21, 2009 letter and groups the projects in three categories. The description of each project in the evidence on pages 10 to 28 follows the Item #'s used in Table 1. Table 5 on page 46 (Summary of Development Work for Major Green Projects in Bridge and Test Years) shows Hydro One's planned expenditures on OM&A Development projects but the projects are listed in a different order using a different numbering system.

Please complete the following Table.

Summary of Development OM&A for Schedule A Green Energy Projects ($ M)							
Item #	**Investment Description**	**Item Number as per Schedule A**	**OM&A 2010**	**OM&A 2011**	**OM&A 2012**	**Total Cost**	**Target In-Service Year**
Projects where Preliminary Development Work is Underway							
1							
2							
3							
4							
5							
6							
7							
Projects where Development Work will begin once OPA confirms Project Need							
8							
9							
10							
11							
12							
13							
14							
15							
Projects where Development Work is Not Planned in the Test Years							
16							
17							
18							
Total Costs							

Response

The numbering of the projects in Table 1 and Table 5 is different but the project names are the same. For the cost information requested above, please see Exhibit I, Tab 9, Schedule 78.

Association of Major Power Consumers of Ontario (AMPCO) INTERROGATORY #80 List 1

Interrogatory

9.1 – Are the OM&A and capital amounts in the Green Energy Plan appropriate and based on appropriate planning criteria?

Ref: Ex A/Tab 11/Schedule 4/Page 30/Table 2

Table 2 (Expenditures for Schedule B Projects) shows the total capital expenditures required for Schedule B (Projects to Enable Distribution System Connected Generation) of the September 21, 20009 Minister's Letter and the target in-service year based on five item numbers.

Please provide a breakdown of these estimates for each of the five item numbers by year to arrive at the totals shown in Table 2.

Response

Please see Exhibit I, Tab 1, Schedule 107.

Association of Major Power Consumers of Ontario (AMPCO) INTERROGATORY #81 List 1

Interrogatory

9.1 – Are the OM&A and capital amounts in the Green Energy Plan appropriate and based on appropriate planning criteria?

Ref: Ex A/Tab 11/Schedule 4/Page 47

Hydro One is considering the need for a mechanism to recover OM&A development costs as incurred and might propose a rate rider mechanism. The rider mechanism would recover the costs in a deferral account each year.

Given the materiality of these development costs, currently projected at $160 M for Green Energy Projects ($82.4 M) in the Test Years, has Hydro One considered a variance account to track the difference between the forecast and actual expenditures?

Response

These OM&A costs are being tracked in a deferral account.

Association of Major Power Consumers of Ontario (AMPCO) INTERROGATORY #82 List 1

Interrogatory

9.2 – Are Hydro One's accelerated cost recovery proposals for the Bruce-to-Milton line and for Green Energy projects appropriate?

Ref: Ex A/Tab 11/Schedule 5/Page 6

A) Please identify the reduced borrowing cost benefits that will accrue to ratepayers from this proposal.

B) Please provide an analysis that identifies the incremental customer cost benefit of this proposal over the projected life of the asset, using Hydro One's best estimates of future borrowing cost, tax rates and ROE.

Response

A) Please see Exhibit I, Tab 1, Schedule 122 and Exhibit I, Tab 7, Schedule 11, Part a.

B) Please see Exhibit I, Tab 1, Schedule 122.

Association of Major Power Consumers of Ontario (AMPCO) INTERROGATORY #83 List 1

Interrogatory

9.2 – Are Hydro One's accelerated cost recovery proposals for the Bruce-to-Milton line and for Green Energy projects appropriate?

Ref: Ex A/Tab11/Schedule 5/Page 8/Table 2

Please provide a pro forma version of this Table that compares the customer's impact of requirement for revenue from Hydro One's proposed Construction Work In Progress (CWIP) treatment with a treatment whereby the Board would allow Hydro One to expense interest costs throughout the project life.

Response

Hydro One assumes that "project life" means "construction period" or "pre-inservice period" and that interest costs would be recovered over that period, at the AFUDC rate, rather than recovered using the all-in return as is proposed under the CWIP in ratebase proposal.

Please see Exhibit I, Tab 4, Schedule 74, part a) for the revenue requirement impact in the test years 2011 and 2012 from using the AFUDC rate instead of the weighted average cost of capital.

Association of Major Power Consumers of Ontario (AMPCO) INTERROGATORY #84 List 1

Interrogatory

9.2 – Are Hydro One's accelerated cost recovery proposals for the Bruce-to-Milton line and for Green Energy projects appropriate?

Ref: Ex A/Tab11/Schedule 5/Page 1

The evidence indicates that 100% of annual CWIP expenditures for the 500 kV Bruce to Milton Double Circuit Line project are to be treated as if they were added to rate base until the project is placed in service.

Did Hydro One consider the option of applying CWIP into rate base on a staged basis as construction proceeds? If no, please explain.

Response

Hydro One interprets “staging” to mean that construction costs would be added to ratebase on a month-by-month basis prior to in-service, or at least more frequently than once per year at year-end as the company is proposing to do.

The company did not consider a more frequent interval of ratebasing for CWIP in ratebase purposes as the annual approach coincides with the OEB’s usual practice for rate making purposes, wherein ratebase is calculated on a mid-year basis.

Association of Major Power Consumers of Ontario (AMPCO) INTERROGATORY #85 List 1

Interrogatory

9.2 – Are Hydro One's accelerated cost recovery proposals for the Bruce-to-Milton line and for Green Energy projects appropriate?

Ref: Ex A/Tab 11/Schedule 5/Page 10/Section 6

Table 3 on page 10 lists two projects proposed for Accelerated Cost Recovery of CWIP for annual expenditures in their individual Section 92 applications:

- Northwest Transmission Reinforcement; and
- Algoma x Sudbury Transmission Expansion.

A) Please identify the specific investment risks associated with each of the above projects.

B) Please explain why Hydro One does not feel conventional mechanisms are adequate in connection with the above proposed investments to address investment risk.

C) Please indicate the cost of each project in proportion to current rate base.

Response

A) These are both very large and complex projects. The Northwest project is a Greenfield project which will increase the project risks even further. The following excerpt from Exhibit A, Tab 11, Schedule 4, page 35 explains the risks.

"In addition to the large cost of the Plan, the green projects also have a high degree of risk associated with them. This also supports the need for an alternative funding mechanism. Building such large, complex and multi year projects will present very significant challenges:

1) In almost all cases involving new line construction there will be the need for consultation with First Nations & Metis communities and a number of issues to be resolved around access to the land, financial settlements and compensation and creation of jobs for the communities.
2) There will be major property acquisition issues. In the case of larger projects there will be hundreds of landowners to negotiate with. Most landowners will want to maximize the value of their land. This has been demonstrated in the Bruce to Milton project where even after a very protracted negotiation period expropriation of many properties is required.
3) There will be environmental risks with all of the projects. Most of the projects will require Environmental Assessments and there are numerous issues associated with potential contamination and land remediation, preservation of water bodies and wet lands, protection of cultural and heritage sites and protection of endangered species.
4) There will be timing risks with all the green projects but especially the longer term construction projects. Projects that are initiated under the current policy objectives of the government may be subject to delay, changes or even cancellation if the policy objectives change in future years.

Bruce to Milton and other recent line construction projects have been able to utilize existing or widened corridors and yet the issues encountered as noted above have been substantial. A number of the Green Energy projects will involve true Greenfield projects. The property acquisition and Environmental risks will be significantly multiplied for Greenfield projects. It is expected that Environmental Assessments for Greenfield projects will be more complicated and will take at least two years to complete."

B) Please see Exhibit I, Tab 1, Schedule 122 to explain the reasons why accelerated cost recovery of CWIP is recommended for these projects.

C) The Board approved Rate Base for 2010 is $7,635.9M. The forecast cost of Northwest Transmission Reinforcement represents 5% of rate base and the forecast cost of Algoma x Sudbury Transmission Expansion represents 6% of rate base.