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Susan Frank
Vice President and Chief Regulatory Officer
Regulatory Affairs

BY COURIER

December 23, 2008

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

Dear Ms. Walli:

EB-2008-0272 – Hydro One Networks' 2009-2010 Transmission Rate Application – Responses to Interrogatory Questions

I have attached three (3) copies of Hydro One Networks' responses to Interrogatory questions. I have also provided an index page to show the original intervenor question numbers and the equivalent tab and schedule numbers.

An electronic copy of the complete application, including the attached updates, has been filed using the Board's Regulatory Electronic Submission System (RESS) and the proof of successful submission slip is attached.

Hydro One Networks will post electronic copies of the interrogatory responses on the Hydro One Networks' website for public access. In addition, one copy is being provided for public access at each of the following Hydro One Networks' offices –

Hydro One Networks Head Office, 8th Floor, South Tower, 483 Bay Street, Toronto, Ontario

Hydro One Networks Barrie Field Business Centre, 45 Sarjeant Drive, Barrie, Ontario

Hydro One Networks Peterborough Field Business Centre, 913 Crawford Drive, Peterborough, Ontario

Hydro One Networks Sudbury Field Business Centre, 957 Falconbridge Road, Sudbury, Ontario

Hydro One Networks Merivale Service Centre, 31 Woodfield Drive, Ottawa, Ontario

Hydro One Networks Dundas Field Business Centre, 40 Olympic Drive, Dundas, Ontario

Hydro One Networks Beachville Field Business Centre, 56 Embro Street, Beachville, Ontario

Hydro One Networks Thunder Bay Field Business Centre, 255 Burwood Road, Thunder Bay, Ontario

Copies of the Interrogatories will be provided to Intervenors within the next few business days.

Sincerely,

ORIGINAL SIGNED BY SUSAN FRANK

Susan Frank

Attach.

c. EB-2008-0272 Intervenors

Interrogatory Index						
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BOMA & LPMA	1	24	Tab	2	Schedule	24
BOMA & LPMA	1	25	Tab	2	Schedule	25
Lewis Balogh	1	1	Tab	3	Schedule	1
Lewis Balogh	1	2	Tab	3	Schedule	2
Lewis Balogh	1	3	Tab	3	Schedule	3
Lewis Balogh	1	4	Tab	3	Schedule	4
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Pollution Probe	1	7	Tab	5	Schedule	7
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VECC	1	3	Tab	6	Schedule	3
VECC	1	4	Tab	6	Schedule	4
VECC	1	5	Tab	6	Schedule	5
VECC	1	6	Tab	6	Schedule	6
VECC	1	7	Tab	6	Schedule	7
VECC	1	8	Tab	6	Schedule	8
VECC	1	9	Tab	6	Schedule	9
VECC	1	10	Tab	6	Schedule	10
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VECC	1	24	Tab	6	Schedule	24
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VECC	1	64	Tab	6	Schedule	64
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VECC	1	67	Tab	6	Schedule	67
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PWU	1	4	Tab	7	Schedule	4
PWU	1	5	Tab	7	Schedule	5
PWU	1	6	Tab	7	Schedule	6
Energy Probe	1	1	Tab	8	Schedule	1
Energy Probe	1	2	Tab	8	Schedule	2
Energy Probe	1	3	Tab	8	Schedule	3
Energy Probe	1	4	Tab	8	Schedule	4
Energy Probe	1	5	Tab	8	Schedule	5
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Energy Probe	1	21	Tab	8	Schedule	21
Energy Probe	1	22	Tab	8	Schedule	22
Energy Probe	1	23	Tab	8	Schedule	23
Energy Probe	1	24	Tab	8	Schedule	24
Energy Probe	1	25	Tab	8	Schedule	25
Energy Probe	1	26	Tab	8	Schedule	26
Energy Probe	1	27	Tab	8	Schedule	27
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CME	1	2	Tab	9	Schedule	2
CME	1	3	Tab	9	Schedule	3
CME	1	4	Tab	9	Schedule	4
CME	1	5	Tab	9	Schedule	5
CME	1	6	Tab	9	Schedule	6
CME	1	7	Tab	9	Schedule	7
CME	1	8	Tab	9	Schedule	8
AMPCO	1	1	Tab	10	Schedule	1
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AMPCO	1	9	Tab	10	Schedule	9
AMPCO	1	10	Tab	10	Schedule	10
AMPCO	1	11	Tab	10	Schedule	11

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CCC	1	17	Tab	11	Schedule	17
CCC	1	18	Tab	11	Schedule	18
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CCC	1	37	Tab	11	Schedule	37
CCC	1	38	Tab	11	Schedule	38
CCC	1	39	Tab	11	Schedule	39
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GLP	1	2	Tab	12	Schedule	2
GLP	1	3	Tab	12	Schedule	3
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Ontario Energy Board (Board Staff) INTERROGATORY #1 List 1

Interrogatory

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

Reference: a) ExhA/Tab18/Sched1/p3
b) ExhA/Tab17/Sched1
c) ExhA/Tab15/Sched1
d) ExhA/Tab16/Sched1

Preamble: Compensation: The Board provided the following direction to Hydro One in its decision for file EB-2006-0501 regarding compensation costs, and how they compare to those of other regulated transmission and/or distribution utilities in North America: … the Board directs Hydro One to consult with stakeholders about the type of information to be gathered and the types of utilities and other companies that should be used for comparison purposes.
…the Board expects (Hydro One) to provide empirical evidence which reveals the relative productivity of its workforce in comparison to other utilities
…the Board expects the new study to be comprehensive and reliable with none of the limitations of the PA study.

The pre-filed evidence includes:
Summaries of four stakeholder consultations regarding "Compensation Cost Benchmarking and Productivity."
Transmission Benchmarking Study from First Quartile Consulting (formerly PA Consulting). Hydro One engaged First Quartile to include productivity benchmarking in their transmission benchmark study. In their report, First Quartile stated that "in the specific area of work force productivity measurement and performance, the study is inconclusive, other than to note that the industry doesn't systematically measure productivity for its transmission organizations. First Quartile classifies measures such as cost per asset and cost per km of line maintained as surrogate productivity metrics. "They are really more high-level cost metrics than genuine workforce productivity metrics."
Compensation Cost Benchmarking Study from Mercer/Oliver Wyman. A productivity survey was developed, but had to be simplified in order to engage participation. The 4 resulting indicators are total compensation per: gross fixed assets, MWh sold, km of line, service territory.

Questions:
a) What was the rationale for engaging two consultants to study productivity?
b) Are the indicators used by Mercer/Oliver Wyman comprehensive and reliable in light of the assessment by First Quartile?
c) Did the stakeholders suggest alternate productivity indicators? If so, did the

consultants attempt to collect information on these indicators?

Response

a) In the EB-2006-0501 Decision, Hydro One understood the OEB to direct Hydro One to perform two distinct benchmarking studies for its next Cost of Service application:

1 A compensation/workforce productivity study; and
2 An update to the original PA Consulting performance benchmarking study, focused on Transmission Operations, which would correct the identified deficiencies.

After a complete RFP process with stakeholder involvement, Mercer/Oliver Wyman were engaged to prepare the compensation/workforce productivity benchmarking study. First Quartile, comprised of the former principles of PA Consulting, were engaged to update the PA Consulting performance benchmarking study. The study mandate was expanded to include work force productivity in an attempt to gather additional benchmarking results.

b) Both consultants used comprehensive and reliable indicators that measured productivity in terms of input/output. As there were no standard productivity measures for the industry, both consultants applied measures which could be used to benchmark productivity effectively across different utilities.

The results of the Mercer/Oliver Wyman study showed that, relative to its peers, Hydro One is very productive.

c) According to Exhibit A, Tab 17, Schedule 1, Attachment 1, Appendix 3, page 9, the stakeholders did not suggest any alternate productivity indicators other than the concept of cost ratios.

Cost ratios were used in both studies at Exhibit A, Tab 15, Schedule 2, Attachment 1, page 18 and at Exhibit A, Tab 16, Schedule 2, Attachment 1, page 31, however, while “per customer” is used in the distribution measures, it is not an appropriate indicator for transmission, due to the small number of customers, and the type of customers. (e.g. a large local distribution company, or an individual industrial company directly served by the Transmission Utility).

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

Interrogatory

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

Reference: a) ExhA/Tab18/Sch1/p3
b) ExhC1/Tab3/Sch2/pp6-7

Preamble: Agency Review Panel: The Board provided the following direction to Hydro One in its decision for file EB-2006-0501 regarding the Agency Review Panel: The Board directs Hydro One to track any reduction in executive pay during 2007 and 2008 that results (from) implementing the Panel's recommendations and to report that amount at its next transmission rate case.

Question:
The pre-filed evidence states that, "To date, the positions of Chief Executive Officer and General Counsel have had their salaries reduced." Is the reduction tracked and has the amount been reported in the pre-filed evidence?

Response

The reductions in CEO and General Council salaries are tracked, and the impact of the reduction is reflected in the pre-filed evidence in the Corporate Management Function (Reference Exhibit C1, Tab 2, Schedule 6, Table 2, page 3). The reductions are not specifically identified in the pre-filed evidence, however they are publicly disclosed.

The reduction in salary for these two positions occurred in 2007. The change in the President and CEO position as well as the General Counsel position resulted in reductions of over 40% or $830,000 in total.

The annual compensation for the Chief Executive Officer is identified in the Hydro One Annual Information Form (AIF) for the year ending December 31, 2007. As noted in the 2007 AIF "… setting executive compensation, as recommended by the Agency Review Panel, results in reduced compensation for new executives. The new compensation for the President and Chief Executive Officer Position is 40% less that that of the previous President and Chief Executive Officer. The other executive officer appointment also resulted in compensation consistent with Agency Review Panel direction"

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

Interrogatory

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

Reference: ExhB1/Tab1/Sch1/p.1 L24 – p.2 L4
Preamble: It is stated that:

> *"Hydro One Transmission is requesting an equity return of 8.53% for the 2009 test year and 9.35% for the 2010 test year per the Board's formulaic approach in Appendix B of the Cost of Capital Report. The returns are based on the Long Canada Bond Forecast for 2009 and 2010,using the April 2008 Consensus Forecast. Hydro One assumes that the ROE for each test year will be updated in accordance with the Cost of Capital Report, upon the final decision in this case"*

Question:

a) Please provide detailed calculations of the stated equity returns of 8.53% in 2009 and 9.35% in 2010 as well as copies of any referenced source documents.

b) Please clarify the statement that "Hydro One assumes that the ROE for each test year will be updated in accordance with the Cost of Capital Report, upon the final decision in this case." Please comment specifically on whether or not Hydro One would envisage the Board setting these rates for both 2009 and 2010 at the time of the final decision, or whether Hydro One would envisage the Board applying the 2010 rate that would be determined in accordance with the update process outlined in Appendix B of the Cost of Capital Report which would be applicable to distributors having rates reset in 2010. *(MD)*

Response

a) As per Appendix B of the *Report of the Board on Cost of Capital and 2nd Generation Incentive Regulation for Ontario's Electricity Distributors* (Cost of Capital) report the ROE formula is:

    ROE = 9.35% + 0.75*(LCBF – 5.5%)

Where LCBF is the Long Canada Bond Forecast

The application of ROE the formula for 2009 is:

    ROE = 9.35% + 0.75*(4.4% – 5.5%)
    ROE = 8.53%

The application of ROE the formula for 2010 is:

ROE = 9.35% + 0.75*(5.5% – 5.5%)

ROE = 9.35%

The 30-year Long Canada Bond Forecast rates were calculated based on the April 2008 *Consensus Forecasts*.

	2009	2010
April 2008 *Consensus Forecast* Outlook for the 10 year Government of Canada Bond yield (See Attachment 1, page 17)	3.90%	5.00%
Average difference between 10 and 30 year Government of Canada bond yields during March 2008 - from the Bank of Canada website Series V39055 and Series V39056 (See Attachment 2)	0.50%	0.50%
Long Canada Bond Forecast	4.40%	5.50%

b) Hydro One would envisage the Board setting the ROE for both 2009 and 2010 by following the guidelines described in Appendix B of the December 20, 2006 Cost of Capital Report:

> “ The final ROE will be factored into rates using the Long Canada Bond Forecast based on Consensus Forecasts and Bank of Canada data three months in advance of the effective date for the rate change.”

Specifically, for 2009, the Board would determine the ROE for Hydro One Transmission based upon the March 2009 Consensus Forecasts and Bank of Canada data which would be available in April 2009.

For rates effective January 1, 2010, the Board would determine the ROE based upon the September 2009 Consensus Forecasts and Bank of Canada data which would be available in October 2009.

CANADA APRIL 2008

	Average % Change on Previous Calendar Year																Annual Total	
	Gross Domestic Product		Personal Expenditure		Machinery & Equipment Investment		Pre - Tax Corporate Profits		Industrial Production		Consumer Prices		Industrial Product Prices		Average Hourly Earnings		Housing Starts (thousand units)	
	Produit Intérieur Brut		*Dépenses de Consommation des Ménages*		*Investissement Productif*		*Bénéfices des Sociétés avant impôts*		*Production Industrielle*		*Prix à la Consommation*		*Prix des Produits Industriels*		*Rémunération Horaire Moyenne*		*Construction de Logements mises en chantier, milliers*	
Economic Forecasters	2008	2009	2008	2009	2008	2009	2008	2009	2008	2009	2008	2009	2008	2009	2008	2009	2008	2009
Conf Board of Canada	2.2	3.0	4.2	3.1	10.5	6.2	7.9	6.7	na	na	1.3	1.9	-0.2	1.3	na	na	211	194
Caisse de Depot	1.7	2.5	3.7	3.1	8.0	6.0	na	na	na	na	1.7	2.0	na	na	na	na	212	205
CIBC World Markets	1.6	3.0	4.3	2.9	9.8	6.7	5.1	9.2	na	na	2.4	3.0	na	na	na	na	230	220
Informetrica	1.6	2.3	4.5	2.6	7.0	7.3	4.0	3.5	-4.0	1.4	1.7	1.8	1.0	1.5	3.8	3.0	204	182
Royal Bank of Canada	1.6	2.3	4.3	3.1	8.3	5.5	1.4	3.4	na	na	1.4	1.9	na	na	na	na	216	184
Global Insight	1.6	2.3	5.3	3.0	11.3	8.1	2.1	3.9	-0.8	1.3	1.8	2.1	-3.2	0.5	na	na	209	195
Economap	1.5	2.3	3.8	3.1	6.8	5.5	1.0	4.5	-2.1	1.0	1.9	1.8	-0.5	1.5	3.7	3.0	205	190
Scotia Economics	1.5	2.0	4.3	2.4	8.4	3.9	-2.0	3.0	-1.0	2.0	2.1	2.0	na	na	na	na	215	192
BMO Capital Markets	1.4	2.4	4.2	3.0	7.8	4.0	1.0	4.7	-2.0	0.7	2.0	1.9	0.5	1.0	4.7	4.0	210	200
National Bank Financial	1.4	1.8	3.9	2.5	6.4	7.4	-5.5	1.5	na	na	1.3	2.3	na	na	na	na	200	180
Desjardins	1.3	2.1	5.2	4.6	10.8	6.8	1.2	4.1	na	na	1.9	1.3	-3.8	2.0	4.0	2.7	220	197
JP Morgan	1.1	2.3	3.9	2.5	7.7	5.1	-6.0	7.0	-2.7	2.7	1.8	2.1	-0.9	3.0	3.7	3.5	195	210
Toronto Dominion Bank	1.1	1.8	4.3	2.6	5.2	4.9	2.9	2.6	na	na	1.5	1.9	na	na	na	na	214	205
EDC Economics	1.0	2.3	4.6	3.4	7.5	3.2	-3.3	4.6	na	na	1.6	1.9	na	na	na	na	208	194
Merrill Lynch Canada	0.9	1.4	5.5	3.7	na	na	na	na	na	na	1.6	1.7	na	na	na	na	213	190
University of Toronto	0.9	2.2	4.1	2.0	9.7	5.4	2.0	2.9	na	na	1.5	2.0	na	na	na	na	217	198
Consensus (Mean)	1.4	2.3	4.4	3.0	8.3	5.7	0.8	4.4	-2.1	1.5	1.7	2.0	-1.0	1.5	4.0	3.2	211	196
Last Month's Mean	1.5	2.3	4.1	3.0	8.6	5.9	1.2	4.4	-2.0	1.8	1.6	1.9	-0.8	1.6	3.9	3.2	208	196
3 Months Ago	2.1	2.5	3.4	3.0	7.8	6.0	2.5	4.6	0.5	1.2	1.6	2.0	0.1	1.4	3.3	3.2	205	195
High	2.2	3.0	5.5	4.6	11.3	8.1	7.9	9.2	-0.8	2.7	2.4	3.0	1.0	3.0	4.7	4.0	230	220
Low	0.9	1.4	3.7	2.0	5.2	3.2	-6.0	1.5	-4.0	0.7	1.3	1.3	-3.8	0.5	3.7	2.7	195	180
Standard Deviation	0.3	0.4	0.5	0.6	1.8	1.4	3.9	2.0	1.2	0.7	0.3	0.3	1.8	0.8	0.4	0.5	8	10
Comparison Forecasts																		
IMF (Apr. '08)	1.3	1.9	3.5	2.3							1.6	2.0						
OECD (Dec. '07)	2.4	2.7	3.7	3.2							1.7	1.8						

Government and Background Data

Prime Minister - Mr. Stephen Harper (Conservative). **Government** - The Conservatives lead a minority government, with 124 out of 308 seats in parliament (155 seats are needed for a clear majority). **Next Election** - By 2011 (general election). **Nominal GDP** - C$1,446bn (2006). **Population** - 32.6mn (mid-year, 2006). **C$/$ Exchange Rate** - 1.134 (average, 2006).

Quarterly Consensus Forecasts

Historical Data and Forecasts (bold italics) From Survey of March 10, 2008

	2007 Q3	2007 Q4	2008 Q1	2008 Q2	2008 Q3	2008 Q4	2009 Q1	2009 Q2	2009 Q3	2009 Q4
Gross Domestic Product	3.1	2.9	***1.9***	***1.4***	***1.3***	***1.6***	***2.1***	***2.5***	***2.5***	***2.7***
Personal Expenditure	4.5	5.4	***5.0***	***4.4***	***4.0***	***3.1***	***3.0***	***3.0***	***3.1***	***3.2***
Consumer Prices	2.1	2.5	***1.7***	***1.5***	***1.8***	***1.9***	***1.9***	***1.8***	***1.9***	***2.0***

Percentage Change (year-on-year).

Historical Data

** % change on previous year*	2004	2005	2006	2007
Gross Domestic Product*	3.1	3.1	2.8	2.7
Personal Expenditure*	3.4	3.8	4.2	4.7
Machinery & Eqpt Investment*	9.3	10.8	7.4	5.1
Pre - Tax Corporate Profits*	17.1	11.9	5.0	5.8
Industrial Production*	1.9	1.6	-0.2	0.3
Consumer Prices*	1.8	2.2	2.0	2.2
Industrial Product Prices*	3.2	1.5	2.3	1.6
Average Hourly Earnings*	2.7	2.8	2.9	3.9
Housing Starts, '000 units	233	225	227	228
Unemployment Rate, %	7.2	6.8	6.3	6.0
Current Account, C$ bn	29.1	27.9	23.6	14.2
Federal Govt Budget Balance, fiscal years, C$ bn	1.5	13.2	13.8	9.8 *e*
3 mth Trsy Bill, % (end yr)	2.5	3.4	4.2	3.8
10 Yr Govt Bond, % (end yr)	4.3	4.0	4.1	4.0

e = consensus estimate based on latest survey

Year Average		Annual Total		Fiscal Years (Apr-Mar)		Rates on Survey Date			
						2.4%		3.6%	
Unemploy - ment Rate (%)		Current Account (C$ bn)		Federal Govt Budget Balance (C$ bn)		3 month Treasury Bill Rate (%)		10 Year Government Bond Yield (%)	
Taux de Chômage (%)		*Balance Courante (C$ md)*		*Balance Budgétaire (C$ md)*		*Rendement sur les Bons du Trésor de 3 mois %*		*Rendement des Obligat-ions d'État de 10 ans %*	
2008	2009	2008	2009	FY 08-09	FY 09-10	End Jul'08	End Apr'09	End Jul'08	End Apr'09
5.8	5.8	7.0	5.9	1.6	4.4	3.1	3.5	4.1	4.4
6.2	6.1	0.0	12.0	2.0	7.0	2.7	3.1	3.6	4.5
6.2	6.2	-1.4	2.1	2.5	2.0	2.1	2.7	3.4	3.9
6.1	6.0	-15.0	13.0	5.0	6.0	2.1	2.5	3.6	3.8
6.2	6.5	-2.7	-8.8	na	na	2.3	2.9	3.6	3.9
6.1	6.2	-22.5	-26.6	na	na	2.7	3.5	3.6	3.7
6.2	6.4	-11.0	-15.0	2.0	3.0	2.2	2.9	3.4	3.8
6.0	6.2	-6.0	-15.0	2.3	1.3	1.5	2.1	3.4	4.0
6.1	6.2	-10.0	-18.0	3.0	4.0	2.5	2.8	3.4	3.7
6.2	6.5	0.6	6.7	2.0	2.0	2.4	2.5	3.6	3.9
5.9	5.7	-21.3	-36.0	5.0	8.0	2.5	3.4	3.7	4.1
6.2	6.3	0.7	-2.0	4.5	3.0	2.7	2.9	3.5	3.7
6.0	6.3	-8.6	0.1	na	na	1.9	2.0	3.5	3.8
6.0	6.1	-16.1	na	na	na	2.5	3.0	3.7	3.9
6.1	6.1	-17.0	-33.3	na	na	1.7	2.0	3.4	3.5
6.2	6.3	-2.5	-2.5	na	na	1.8	2.6	3.5	3.9
6.1	6.2	-7.9	-7.8	3.0	4.1	2.3	2.8	3.6	3.9
6.1	6.2	-5.5	-1.4	4.0	4.8				
6.1	6.1	5.4	3.2	4.9	5.6				
6.2	6.5	7.0	13.0	5.0	8.0	3.1	3.5	4.1	4.5
5.8	5.7	-22.5	-36.0	1.6	1.3	1.5	2.0	3.4	3.5
0.1	0.2	8.7	15.7	1.3	2.3	0.4	0.5	0.2	0.3
6.1	6.3								
5.8	5.8								

Resilience Characterises Economic Outlook

Despite the uncertainty surrounding global growth prospects, latest Canadian data have been surprisingly resilient and, in a few cases, even upbeat. January GDP growth rebounded by 0.6% (m-o-m) following December's 0.7% contraction, thanks to broad-based gains in both the household and industrial sectors. Retail trade rose by 1.2% on clothing, furniture, car, electronics and food purchases, highlighting the underlying strength of consumer spending. The credit crunch will undoubtedly have an impact on purchasing decisions this year, though, as will recent signs that the job market may be faltering. Indeed, March payrolls moderated from a barn-storming 43,300 rise in the previous month to only a 14,600 increase, while unemployment jumped from 5.8% to 6.0%. Our panel's forecast for the jobless rate is unchanged, however, while observers point out that employment is still growing – in contrast with US indicators of job creation. Personal expenditure forecasts have therefore been upgraded to an impressive 4.4% for this year. Moreover, while the global economy is plagued by rising inflation concerns (especially food and fuel prices), Canadian consumer price inflation remains noticeably muted. Indeed, increases in the headline CPI moderated from 2.2% (y-o-y) in January to 1.8% in the following month as a 1%-point cut in the federal Goods and Services tax took effect. With automobile retailers slashing car prices to compete with more competitive US sellers and the C$ remaining strong, inflation is not expected to pick up significantly. Our panel's 2008 consumer price expectations have consequently edged up only moderately this month, to 1.7%. This hints at the Bank of Canada's flexibility in terms of potential monetary loosening; indeed, a 50 basis-point rate cut is expected soon (see below).

Industry saw an unexpected turnaround in fortunes, at odds with its closely-linked US neighbour. January's 1.7% (m-o-m) jump in manufacturing went some way towards halving December's sharp 3.4% drop, while industrial production as a whole rose by 1.1%. This compared favourably with a muted 0.1% rise in US production during the same month. Elsewhere, January saw a rebound in factory shipments and new orders. This year's production expectations remain in sharply negative territory, though.

Direction of Trade – First Half 2007

Major Export Markets (% of Total)		Major Import Suppliers (% of Total)	
United States	76.4	United States	60.3
China	3.0	China	7.5
United Kingdom	2.8	Mexico	3.5
Asia (ex. Japan)	*6.1*	*Asia (ex. Japan)*	*12.4*
Latin America	*3.1*	*Latin America*	*6.1*
Eastern Europe	*0.8*	*Africa*	*1.6*

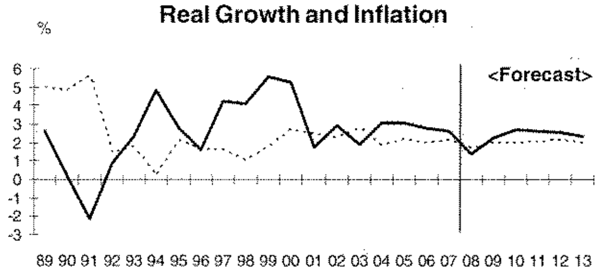
Likelihood of a Bank of Canada Interest Rate Change

Our panel's estimated average probability of a change in the **overnight lending rate (3.50% on survey date) at or before the next key policy meeting** is:

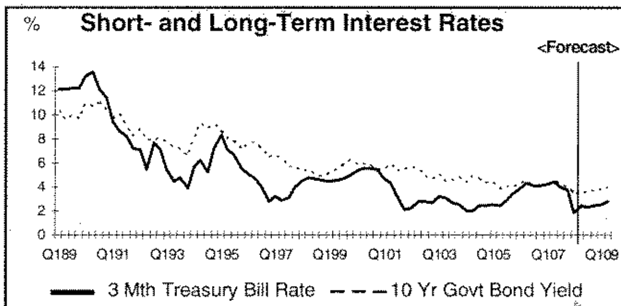
INCREASE		NO CHANGE		DECREASE		
0.0	+	16.1	+	83.9	=	100 %

Most likely rate change mentioned: -0.50 %

Real Growth and Inflation



Short- and Long-Term Interest Rates



continued from page 3

France

* % change over previous year	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014-2018[1]
	Historical				Consensus Forecasts						
Gross Domestic Product*	2.3	1.7	2.2	1.9	1.5	1.7	2.1	2.1	2.1	2.1	2.1
Household Consumption*	2.5	2.2	2.3	2.1	1.9	2.0	2.3	2.3	2.2	2.2	2.2
Business Investment*	3.6	2.7	4.6	5.1	2.7	2.6	3.8	3.5	3.4	3.4	3.4
Industrial Production*	2.3	0.4	1.3	1.8	1.4	1.5	2.7	2.2	2.1	2.1	2.0
Consumer Prices*	2.1	1.8	1.6	1.5	2.5	1.8	1.8	1.8	1.9	1.8	1.8
Current Account Balance (Euro bn	8.5	-15.7	-22.5	-24.4	-30.8	-32.6	-24.8	-23.7	-20.4	-15.0	-12.5
10 Year Treasury Bond Yield, %[2]	3.7	3.3	4.0	4.4	4.0 [3]	4.2 [4]	4.4	4.5	4.5	4.5	4.5

United Kingdom

* % change over previous year	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014-2018[1]
	Historical				Consensus Forecasts						
Gross Domestic Product*	3.3	1.8	2.9	3.0	1.6	1.7	2.0	2.2	2.3	2.4	2.4
Household Consumption*	3.5	1.5	1.9	3.0	1.5	1.4	1.7	2.0	2.1	2.2	2.3
Gross Fixed Investment*	5.9	1.5	7.6	6.2	2.1	1.5	1.7	1.9	2.6	2.9	3.2
Manufacturing Production*	2.0	-1.2	1.5	0.6	0.2	0.7	0.4	0.9	1.1	1.2	1.1
Retail Prices (underlying rate)*	2.2	2.3	2.9	3.2	3.4	2.5	2.7	2.7	2.6	2.6	2.7
Consumer Prices*	1.3	2.1	2.3	2.3	2.6	2.0	2.2	2.2	2.1	2.1	2.1
Current Account Balance (£ bn)	-19.3	-31.0	-50.7	-57.8	-58.9	-52.8	-51.8	-51.2	-51.9	-53.7	-60.7
10 Year Treasury Bond Yield, %[2]	4.5	4.1	4.7	4.6	4.4 [3]	4.5 [4]	4.9	5.1	5.1	5.0	5.0

Italy

* % change over previous year	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014-2018[1]
	Historical				Consensus Forecasts						
Gross Domestic Product*	1.0	0.2	1.9	1.6	0.6	1.1	1.5	1.4	1.4	1.4	1.4
Household Consumption*	0.7	0.6	1.5	1.6	0.8	1.1	1.4	1.4	1.5	1.4	1.4
Gross Fixed Investment*	1.3	-0.2	2.4	1.8	0.9	1.2	1.7	1.7	1.5	1.4	1.4
Industrial Production*	-0.3	-0.8	2.6	-0.2	-0.1	0.9	1.2	1.2	1.1	1.0	1.0
Consumer Prices*	2.2	2.0	2.1	1.8	2.9	2.1	2.0	1.9	1.9	2.0	2.0
Current Account Balance (Euro bn)	-13.1	-23.4	-38.2	-36.5	-37.6	-36.2	-32.5	-26.5	-25.2	-24.3	-22.3
10 Year Treasury Bond Yield, %[2]	3.8	3.5	4.2	4.6	4.1 [3]	4.2 [4]	4.6	4.7	4.8	4.7	4.7

Canada

* % change over previous year	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014-2018[1]
	Historical				Consensus Forecasts						
Gross Domestic Product*	3.1	3.1	2.8	2.7	1.4	2.3	2.7	2.6	2.6	2.3	2.3
Personal Expenditure*	3.4	3.8	4.2	4.7	4.4	3.0	2.7	2.6	2.4	2.3	2.2
Machinery & Eqpt Investment*	9.3	10.8	7.4	5.1	8.3	5.7	4.5	4.0	4.0	3.8	3.3
Industrial Production*	1.9	1.6	-0.2	0.3	-2.1	1.5	2.3	2.3	2.4	2.3	2.3
Consumer Prices*	1.8	2.2	2.0	2.2	1.7	2.0	2.0	2.1	2.1	2.0	2.0
Current Account Balance (C$ bn)	29.1	27.9	23.6	14.2	-7.9	-7.8	-9.2	-6.1	-6.1	-5.4	-9.7
10 Year Treasury Bond Yield, %[2]	4.3	4.0	4.1	4.0	3.6 [3]	3.9 [4]	5.0	5.2	5.2	5.1	5.1

Euro zone

* % change over previous year	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014-2018[1]
	Historical				Consensus Forecasts						
Gross Domestic Product*	1.9	1.7	2.9	2.6	1.5	1.7	1.9	2.0	2.0	2.0	2.0
Private Consumption*	1.5	1.6	1.8	1.5	1.3	1.6	1.8	1.8	1.9	1.9	1.8
Gross Fixed Investment*	2.0	3.1	5.3	4.2	2.4	2.2	2.7	3.0	2.9	2.8	2.8
Industrial Production*	2.1	1.4	4.0	3.4	2.0	1.9	2.2	2.3	2.1	2.0	1.9
Consumer Prices*	2.1	2.2	2.2	2.1	2.9	2.1	2.0	2.0	2.0	2.0	2.0
Current Account Balance (Euro bn)	59.8	7.1	-13.7	14.9	-2.7	-2.1	-2.8	-2.8	-1.5	-5.0	-5.0

[1] Signifies average for period [2] End period [3] End July, 2008 [4] End April, 2009

BANK OF CANADA
BANQUE DU CANADA

DAILY Series:

V39055: Government of Canada benchmark bond yields, 10 year		
Low	17/03/2008	3.40
Average	03/03/2008 - 31/03/2008	3.51
High	05/03/2008	3.64
03/03/2008	3.61	
04/03/2008	3.64	
05/03/2008	3.64	
06/03/2008	3.55	
07/03/2008	3.56	
10/03/2008	3.52	
11/03/2008	3.58	
12/03/2008	3.52	
13/03/2008	3.51	
14/03/2008	3.48	
17/03/2008	3.40	
18/03/2008	3.48	
19/03/2008	3.44	
20/03/2008	3.45	
21/03/2008	Bank holiday	
24/03/2008	3.52	
25/03/2008	3.48	
26/03/2008	3.46	
27/03/2008	3.46	
28/03/2008	3.45	
31/03/2008	3.43	

BANK OF CANADA
BANQUE DU CANADA

DAILY Series:

V39056: Government of Canada benchmark bond yields, long-term		
Low	31/03/2008	3.94
Average	03/03/2008 - 31/03/2008	4.01
High	05/03/2008	4.13
03/03/2008	**4.08**	
04/03/2008	**4.11**	
05/03/2008	**4.13**	
06/03/2008	**4.08**	
07/03/2008	**4.07**	
10/03/2008	**4.04**	
11/03/2008	**4.06**	
12/03/2008	**4.02**	
13/03/2008	**4.03**	
14/03/2008	**4.02**	
17/03/2008	**3.97**	
18/03/2008	**3.99**	
19/03/2008	**3.94**	
20/03/2008	**3.94**	
21/03/2008	Bank holiday	
24/03/2008	**3.98**	
25/03/2008	**3.94**	
26/03/2008	**3.96**	
27/03/2008	**3.97**	
28/03/2008	**3.95**	
31/03/2008	**3.94**	

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

Interrogatory

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

Reference: ExhB1/Tab1/Sch1/p.2 L12-L16
Preamble:
It is stated that:

> *"For 2009 and 2010, the deemed short-term rates are 4.47% and 4.75%, respectively, using the April 2008 Consensus Forecast. Hydro One assumes that the deemed short term debt rate for each test year will be updated in accordance with the Cost of Capital Report, upon the final decision in this case."*

Question/Request:

a) Please provide detailed calculations of the stated deemed short-term rates of 4.47% in 2009 and 4.75% in 2010 as well as copies of any referenced source documents.

b) Please clarify the statement that "Hydro One assumes that the deemed short term debt rate for each test year will be updated in accordance with the Cost of Capital Report, upon the final decision in this case." Please comment specifically on whether or not Hydro One would envisage the Board setting these rates for both 2009 and 2010 at the time of the final decision, or whether Hydro One would envisage the Board applying the 2010 rate that would be determined in accordance with the update process outlined in the Cost of Capital Report which would be applicable to distributors having rates reset in 2010.

Response

a) The calculation of the deemed short term debt rate is discussed on lines 18 to 24 of page 5 and lines 1 to 5 of page 6 of Exhibit A, Tab 14, Schedule 2. As per page 15 of the *Report of the Board on Cost of Capital and 2nd Generation Incentive Regulation for Ontario's Electricity Distributors* (Cost of Capital) report, the deemed short term debt rate is calculated as the 3 month Bankers Acceptance rate plus a fixed spread of 25 basis points.

   For 2009 the 3 month Bankers Acceptance rate is calculated as the 12 month out (April 2009) 3 month T-bill rate forecast from the April 2008 Consensus Forecast plus the March 2008 average spread between the 3 month Bankers Acceptance rate and the 3 month T-bill rate. The forecast deemed short term rate for 2009 is calculated as follows:

	2009
April 2008 *Consensus Forecast* Outlook for the 3 month T-bill yield (12 month out Apr 09 - page 17 see Exhibit I, Tab 1, Schedule 3, Attachment 1)	2.80%
Average difference between 3 month T-bill and 3 month Bankers Acceptance yields during March 2008 - from the Bank of Canada website Series V39065 and Series V39071(see Attachment 1)	1.42%
3 month Bankers Acceptance forecast rate	4.22%
Plus fixed spread of 25 basis points	0.25%
Forecast Deemed Short term debt rate	4.47%

For 2010 the 3 month Bankers Acceptance rate is based on the April 2008 *Global Insight* forecast (see Attachment 2). The forecast deemed short term rate for 2010 is calculated as follows:

	2010
3 month Bankers Acceptance forecast rate	4.50%
Plus fixed spread of 25 basis points	0.25%
Forecast Deemed Short term debt rate	4.75%

b) Hydro One would envisage the Board setting the deemed short term debt rates for both 2009 and 2010 in a manner consistent with that for setting ROE, as outlined in the response to Exhibit I, Tab 1, Schedule 3, Part b). This would follow the guidelines described on page 16 of the December 20, 2006 Cost of Capital Report:

> "Further, consistent with updating of the ROE and deemed long-term rate, the deemed short-term rate will be updated using data available three full months in advance of the effective date of the rates."

Specifically, for 2009, the Board would determine the deemed short term rate for Hydro One Transmission based upon the March 2009 Consensus Forecasts and Bank of Canada data which would be available in April 2009.

For rates effective January 1, 2010, the Board would determine the deemed short term rate based upon the September 2009 Consensus Forecasts and Bank of Canada data which would be available in October 2009.

BANK OF CANADA
BANQUE DU CANADA

DAILY Series:

V39065: Treasury Bills - 3 month		
Low	20/03/2008	1.43
Average	03/03/2008 - 31/03/2008	2.16
High	03/03/2008	2.98
03/03/2008	**2.98**	
04/03/2008	**2.90**	
05/03/2008	**2.83**	
06/03/2008	**2.56**	
07/03/2008	**2.40**	
10/03/2008	**2.36**	
11/03/2008	**2.35**	
12/03/2008	**2.29**	
13/03/2008	**2.26**	
14/03/2008	**2.25**	
17/03/2008	**2.00**	
18/03/2008	**2.00**	
19/03/2008	**1.90**	
20/03/2008	**1.43**	
21/03/2008	Bank holiday	
24/03/2008	**1.65**	
25/03/2008	**1.85**	
26/03/2008	**1.72**	
27/03/2008	**1.76**	
28/03/2008	**1.83**	
31/03/2008	**1.87**	

BANK OF CANADA
BANQUE DU CANADA

DAILY Series:

V39071: Bankers' acceptances - 3 month		
Low	20/03/2008	3.54
Average	03/03/2008 - 31/03/2008	3.58
High	03/03/2008	3.70
03/03/2008	3.70	
04/03/2008	3.62	
05/03/2008	3.59	
06/03/2008	3.60	
07/03/2008	3.59	
10/03/2008	3.58	
11/03/2008	3.57	
12/03/2008	3.58	
13/03/2008	3.57	
14/03/2008	3.54	
17/03/2008	3.58	
18/03/2008	3.55	
19/03/2008	3.54	
20/03/2008	3.54	
21/03/2008	Bank holiday	
24/03/2008	3.55	
25/03/2008	3.56	
26/03/2008	3.58	
27/03/2008	3.58	
28/03/2008	3.58	
31/03/2008	3.55	

GLOBAL INSIGHT FORECAST SUMMARY April 2008)

04/11/08

	2008	2009	2010	2011	2012	2013	2014	2015
INTEREST RATES	(Percent)							
U.S. 3 MONTH LIBOR	2.85	3.13	4.82	5.24	5.24	5.24	5.24	5.24
CDA 3 MONTH B.A.	3.07	3.70	4.50	5.12	5.12	4.87	4.87	4.87
3 MONTH T-BILLS								
U.S.	1.55	2.00	4.04	4.59	4.59	4.59	4.59	4.59
Canada	2.76	3.58	4.38	5.00	5.00	4.75	4.75	4.75

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

Interrogatory

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

Reference: ExhB1/Tab1/Sch1/p.3 L10-L14
Preamble:
It is stated that:
"The deemed long-term debt rate for 2009 is 6.19% and that for 2010 is 7.29%, based on the approach in Appendix A of the Cost of Capital report, using the April 2008 Consensus Forecast. Hydro One assumes that the deemed long term debt rate for each test year will be updated in accordance with the Cost of Capital Report, upon the final decision in this case."
Question/Request:

a) Please provide detailed calculations of the stated deemed long-term debt rates of 6.19% in 2009 and 7.29% in 2010 as well as copies of any referenced source documents.
b) Please clarify the statement that "Hydro One assumes that the deemed long term debt rate for each test year will be updated in accordance with the Cost of Capital Report, upon the final decision in this case." Please comment specifically on whether or not Hydro One would envisage the Board setting these rates for both 2009 and 2010 at the time of the final decision, or whether Hydro One would envisage the Board applying the 2010 rate that would be determined in accordance with the update process outlined in Appendix B of the Cost of Capital Report which would be applicable to distributors having rates reset in 2010.

Response

a) The calculation of the deemed long term debt rate is discussed on lines 5 to 17 of page 5, Exhibit A, Tab 14, Schedule 2.

   The deemed long-term debt rate is calculated as the Long Canada Bond Forecast plus the average spread on "A/BBB" rated corporate bonds as per Appendix A of the *Report of the Board on Cost of Capital and 2nd Generation Incentive Regulation for Ontario's Electricity Distributors* (Cost of Capital) Report.

   The forecast for 2009 and 2010 is derived by adding the 30-year Government of Canada forecast to the March 2008 spread between the average actual 30-year Government of Canada bond yield and the average DEX Long Term Corporate Bond Index – Yield inferred from the graph on www.pcbond.com. The data for this series is no longer available on the Bank of Canada website (i.e. Series V121791 – as referred to in Appendix A).

The 30-year Long Canada Bond Forecast rates were calculated based on the April 2008 *Consensus Forecasts*. The forecast deemed long term debt rate for 2009 and 2010 is calculated as follows.

	2009	2010
April 2008 *Consensus Forecast* Outlook for the 10 year Government of Canada Bond yield (page 28)*	3.90%	5.00%
Average difference between 10 and 30 year Government of Canada bond yields during March 2008 – data from the Bank of Canada website Series V39055 and Series V39056**	0.50%	0.50%
Long Canada Bond Forecast	4.40%	5.50%
All Corporates Long-term Bond spread (yield inferred from graph on www.pcbond.com)	1.79%	1.79%
Deemed Long Term Debt Rate	6.19%	7.29%

* Exhibit I, Tab 1, Schedule 3, see Attachment 1
** Exhibit I, Tab 1, Schedule 3, see Attachment 2

b) Hydro One would envisage the Board setting the deemed long term debt rates for both 2009 and 2010 in a manner consistent with that for setting ROE, as outlined in the response to Exhibit I, Tab 1, Schedule 3, Part b). This would follow the guidelines described on page 14 of the December 20, 2006 Cost of Capital Report:

> "The deemed long-term rate will be calculated using data available three full months in advance of the effective date of the rate change."

Specifically, for 2009, the Board would determine the deemed long-term rate for Hydro One Transmission based upon the March 2009 Consensus Forecasts and Bank of Canada and other data which would be available in April 2009.

For rates effective January 1, 2010, the Board would determine the deemed long term rate based upon the September 2009 Consensus Forecasts and Bank of Canada and other data which would be available in October 2009.

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

Interrogatory

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

Reference: ExhB1/Tab2/Sch1/p.5
Preamble: Table 3, "Forecast Debt Issues for 2009 and 2010," lists the fixed rate Medium Term Notes which Hydro One Transmission plans to issue in 2009 and 2010.
Question:
Please state how it was determined to issue this debt in equal 5, 10 and 30 year increments and whether this approach to debt issuance is normal practice for Hydro One.

Response

As discussed on lines 17 to 19 of page 4, Exhibit B1, Tab 2, Schedule 1, for 2009 and 2010 planning purposes it is assumed that debt issuance will be evenly distributed over the standard five, ten and 30 year terms which are preferred by investors. This is a normal planning assumption for Hydro One. Hydro One has completed the majority of its issuance in these terms. The actual term of issuance will depend on market conditions and investor receptiveness for particular terms at the time of issue.

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

Interrogatory

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

Reference: ExhB1/Tab2/Sch1/p.6
Preamble: Table 4, "Forecast Yield for 2008-2010 Issuance Terms," summarizes the derivation of the forecast Hydro One Inc. yield for each of the planned issuance terms for 2009 and 2010.
Question:

a) For each yield in this table, please state whether it was directly sourced from the April 2008 Consensus Forecasts and if so, please provide the reference. If any yield was not directly sourced, please state what adjustments were made and the sources of the adjustments

b) Please provide the indicative new issue spreads for March 2008 on which Hydro One's credit spreads over the Government of Canada bonds are based.

c) Please provide an update of this table based on market conditions as of November 2008.

Response

a) The derivation of the yields shown in Table 4 is discussed on lines 5 to 13 of page 6 of Exhibit B1, Tab 2, Schedule 1.

The 10 year Government of Canada yield forecast of 3.60% for 2008, 3.90% for 2009 and 5.00% for 2010 is directly sourced from page 28 of the April 2008 *Consensus Forecast* (see Exhibit I. Tab 1, Schedule 3, Attachment 1). The 2008 rate is based on the 3 month out (July 2008) forecast and the 2009 rate is based on the 12 month out (April 2009) forecast.

The 30 year Government of Canada yield forecast of 4.10% for 2008, 4.40% for 2009 and 5.50% for 2010 was derived by adding a yield spread of 0.50% to the 10 year Government of Canada yield forecast. The 0.50% spread is calculated as the March 2008 average spread between the 30 year Government of Canada Bond yield (Series V39056) and the 10 year Government of Canada Bond yield (Series V39055) from the Bank of Canada website (see Attachment 1 for both). This average spread adjustment is consistent with the methodology in Appendix B of the *Report of the*

Board on Cost of Capital and 2nd Generation Incentive Regulation for Ontario's Electricity Distributors (Cost of Capital) report.

The 5 year Government of Canada yield forecast of 3.04% for 2008, 3.34% for 2009 and 4.44% for 2010 was derived by adding a yield spread of -0.56% to the 10 year Government of Canada yield forecast. The -0.56% spread is calculated as the March 2008 average spread between the 5 year Government of Canada Bond yield (Series V39053) and the 10 year Government of Canada Bond yield (Series V39055) from the Bank of Canada website(see Attachment 1 for both). Similarly, this average spread adjustment is consistent with the methodology in Appendix B of the Cost of Capital report.

The Hydro One credit spreads applicable to 5, 10 and 30 year terms are shown in part (b).

b)

Indicative Average New Issue Spreads from Hydro One's Medium Term Note Dealer Group

Date	5 year	10 year	30 year
10-Mar-08	1.01%	1.14%	1.35%
17-Mar-08	1.05%	1.18%	1.38%
24-Mar-08	1.05%	1.17%	1.37%
31-Mar-08	1.05%	1.19%	1.39%
March 2008 Avg	1.04%	1.17%	1.37%

c)

Indicative Average New Issue Spreads from Hydro One's Medium Term Note Dealer Group

Date	5 year	10 year	30 year
3-Nov-08	2.14%	2.37%	2.57%
10-Nov-08	2.15%	2.36%	2.56%
17-Nov-08	2.12%	2.33%	2.51%
24-Nov-08	2.25%	2.45%	2.61%
November 2008 Avg	2.16%	2.38%	2.57%

BANK OF CANADA
BANQUE DU CANADA

DAILY Series:

V39053: Government of Canada benchmark bond yields, 5 year		
Low	17/03/2008	2.74
Average	03/03/2008 - 31/03/2008	2.95
High	03/03/2008	3.09
03/03/2008	3.09	
04/03/2008	3.08	
05/03/2008	3.06	
06/03/2008	2.95	
07/03/2008	2.97	
10/03/2008	2.94	
11/03/2008	3.03	
12/03/2008	2.97	
13/03/2008	2.93	
14/03/2008	2.86	
17/03/2008	2.74	
18/03/2008	2.90	
19/03/2008	2.89	
20/03/2008	2.91	
21/03/2008	Bank holiday	
24/03/2008	3.05	
25/03/2008	3.00	
26/03/2008	2.93	
27/03/2008	2.92	
28/03/2008	2.91	
31/03/2008	2.91	

BANK OF CANADA
BANQUE DU CANADA

DAILY Series:

V39055: Government of Canada benchmark bond yields, 10 year		
Low	17/03/2008	3.40
Average	03/03/2008 - 31/03/2008	3.51
High	05/03/2008	3.64
03/03/2008	3.61	
04/03/2008	3.64	
05/03/2008	3.64	
06/03/2008	3.55	
07/03/2008	3.56	
10/03/2008	3.52	
11/03/2008	3.58	
12/03/2008	3.52	
13/03/2008	3.51	
14/03/2008	3.48	
17/03/2008	3.40	
18/03/2008	3.48	
19/03/2008	3.44	
20/03/2008	3.45	
21/03/2008	Bank holiday	
24/03/2008	3.52	
25/03/2008	3.48	
26/03/2008	3.46	
27/03/2008	3.46	
28/03/2008	3.45	
31/03/2008	3.43	

BANK OF CANADA
BANQUE DU CANADA

DAILY Series:

V39056: Government of Canada benchmark bond yields, long-term		
Low	31/03/2008	3.94
Average	03/03/2008 - 31/03/2008	4.01
High	05/03/2008	4.13
03/03/2008	4.08	
04/03/2008	4.11	
05/03/2008	4.13	
06/03/2008	4.08	
07/03/2008	4.07	
10/03/2008	4.04	
11/03/2008	4.06	
12/03/2008	4.02	
13/03/2008	4.03	
14/03/2008	4.02	
17/03/2008	3.97	
18/03/2008	3.99	
19/03/2008	3.94	
20/03/2008	3.94	
21/03/2008	Bank holiday	
24/03/2008	3.98	
25/03/2008	3.94	
26/03/2008	3.96	
27/03/2008	3.97	
28/03/2008	3.95	
31/03/2008	3.94	

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

Interrogatory

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

Reference: ExhA/Tab13/Sch1/p4/Sec3.1
Preamble: Hydro One indicates that over the next 2-3 years Planning Standards and Operating Policies will be brought into compliance with mandatory reliability standards.
Question/Request: Please identify the costs estimated for this conversion and the programs in which those costs occur in the application.

Response

The reference text of the evidence refers to an effort that is being conducted by NERC. Hydro One provides guidance, influence and support to the Standards Development initiatives through participation on various NERC Committees and Drafting Teams and on NPCC task forces. In addition, Hydro One reviews and submits comments to the proposed drafts.

As each new standard become effective in the Province of Ontario, Hydro One is required to comply. Revisions to internal governance documentation such as policies, directives and operating instructions are among the changes needed to align with the requirements of the new standards. The cost for this revision effort, plus the cost of representation referred to above on the NERC Committees and NPCC task forces, will be about $1M in 2009 and is included in the budgets for Asset Management (Exhibit C1, Tab 2, Schedule 8, pg 3, Table 1) and Operations (Exhibit C1, Tab 2, Schedule 4, pg3, Table 1).

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

Interrogatory

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

Reference: ExhA/Tab13/Sch1/p4/Sec3.3
Preamble: The application indicates in the reference that "Hydro one commenced our IFRS conversion project in 2007 and established a formal project governance structure for this project."
Question/Request: Please
a) identify the costs and budgets in 2007 and 2008 of this project
b) identify the programs in which those costs occur in the test years
c) describe the formal project governance structure for this project

Response

a) There were no incremental costs in 2007 relating to IFRS as work was performed internally by existing staff. The 2008 budget for the IFRS project is $2.2M which includes costs for diagnostic, design and planning and solution development.

b) The IFRS project costs for the 2009 and 2010 test years are $3.1M and $1.7M, respectively. These costs are included in the 2009 and 2010 Finance Function amounts as per Exhibit C1, Tab 2, Schedule 6, Table 3 on page 5, and as discussed on page 6, lines 14 to 16.

c) As a publicly accountable enterprise (PAE), Hydro One is required to comply with IFRS commencing in 2011. PAEs include listed companies and any other organizations that are responsible to large or diverse groups of stakeholders. The goal of IFRS is to improve financial reporting internationally by establishing a single set of high quality, consistent, and comparable reporting standards. As a public debt issuer, compliance with IFRS for Hydro One is mandatory to ensure transparency to stakeholders. To ensure a smooth transition, a formal governance structure has been established.

   The formal governance structure starts with the Project Lead who reports through to the Project Executive Team (PET), the Executive Committee (EC) and the Audit and Finance Committee of Hydro One's Board. The Project Lead has overall accountability for delivery of the project. The Project Lead's roles and responsibilities include providing guidance, oversight and input to specific key decisions as required; acting as a direct contact point to resolve key project issues;

representing the project at various Committee levels and reviewing resource requirements and any scope changes.

The Project Lead reports to the IFRS PET quarterly. The PET comprises senior members from across the business of the Company who will be largely impacted by IFRS. The PET provides the overall project management and guidance for the IFRS Project, including reviewing key project decisions; confirming understanding of the accounting policy choices Hydro One makes, and providing business expertise in their respective areas.

The Project Lead further reports to the EC quarterly. The EC comprises the senior executives of the Company. The EC provides executive oversight to the IFRS Project, including acting as a guiding/decision making group; reviewing high-priority project risks on an ongoing basis, and ensuring project objectives remain consistent.

Last, the Project Lead reports to the Audit and Finance Committee quarterly on the status of the project, as well as providing training to the Audit and Finance Committee. This committee is responsible for discussing with the external auditors the quality and acceptability of the accounting principles, reviewing with management significant changes to business processes and resulting changes to internal control over financial reporting, and reviewing significant accounting and reporting issues and understand their impact on the financial statements.

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

Interrogatory

Issue 2.1
Is the Load Forecast and Methodology appropriate and have the impacts of Conservation and Demand Management initiatives been suitably reflected?

Reference:
Preamble: Since the filing of the application, given the current economic situation, has Hydro One assessed the situation and identified any specific issues that may have a material impact on its application, including:

Load forecasts
Capital expenditure sustainment, development, operations and shared services
OM&A
Cost of capital
Other?

Questions:
a) If so, can Hydro One provide the necessary evidence and an estimate of the timing of any update including necessary calculations?
b) For each of the categories where applicable please provide a prioritization of programs which might be affected by the economic situation.
c) Please provide a list of criteria and the rationale that Hydro One would consider in the prioritization and selection of 2009 and 2010 OM&A and Capital projects in its application.
d) Please identify, individually, OM&A and Capital programs and/or projects that Hydro One would consider as a candidate for a deferral, cut, or partial adjustment, given the current economic situation. Please identify these programs, if any, in a ranking order that Hydro One would consider, using a ranking of "1" as the first suitable candidate, ranking of "2" as the second suitable candidate, ranking of "3" as the third suitable candidate, etc.
e) Please describe the expected impacts on Hydro One's revenue requirement, operations and service quality and reliability to customers if the identified programs are reduced, deferred or cut during the economic downturn.

Response

a) Prior to the start of the oral hearing Hydro One intends to file an update to the evidence to reflect actual OM&A and capital spending for the 2008 bridge year. Hydro One is aware of the deteriorating economic climate and the need to support infrastructure improvements. These circumstances may require Hydro One to file a more extensive update in the future.

b) The load forecast and the cost of capital are two areas which are most likely to be impacted by an economic downturn. Given the current economic climate, Ontario has most likely moved into recession in the last quarter of 2008. At this time, it is difficult to predict the depth or length of the recession, but there is no doubt that Hydro One's submitted load forecast will be negatively impacted. As referenced in a) above, this impact may require Hydro One to file a more extensive update in the future.

As noted in response to Board staff interrogatories 3, 4 and 5, Hydro One's assumption is that the return on equity, cost of short term and deemed debt will be updated by the Board in accordance with the process outlined in Appendix B of the Cost of Capital Report. These updates will capture any recessionary impacts on the cost of capital components for the two test years.

The OM&A and the Sustaining, Operations and Shared Services Capital spending is largely driven by the needs of an aging asset base and Hydro One's commitment to meeting all regulatory, compliance, safety and environmental objectives. During recessionary times governments promote infrastructure projects. Hydro One's capital programs are all largely infrastructure related. As such, overall, the Company does not anticipate any downward pressure on its Capital program. In fact, the potential exists for an increase in Capital spending in some areas. For example, the government has asked the OPA to review the IPSP with a view to increasing the amount and diversity of renewable energy sources, improving transmission capacity in the orange zones, and increasing the availability of distributed generation. This direction is likely to result in increased transmission facilities, and it is quite possible that some of this increase will involve rate base investments given the benefits to all Ontario customers.

The potential for increases in Capital spending is expected to offset any reduction in customer demand driven projects that may result from recessionary forces. Hydro One notes that the number of Load Customer Connection projects planned for in-service in the test years represents approximately 1% of the total rate base in 2010.

The Company has not seen any downward pressure on material and/or contractor costs to date. In many cases Hydro One has locked in contracts for equipment purchases in order to guarantee timely delivery and for quality assurance purposes. As such, the current economic situation, including commodity price changes and foreign exchange fluctuations, will not impact the test year spending plans in these areas.

In addition, given approximately 90% of Hydro One's labour force is governed by collective agreements as described at Exhibit C1, Tab 3, Schedule 2, over the two test years, there will be no reductions in labour costs.

c) The process and criteria Hydro One uses to prioritize its work programs is detailed in Exhibit A, Tab 14, Schedule 5.

d) Given the response to part b) above Hydro One does not believe a re-prioritization of its programs is required as a result of the current economic situation. As circumstances change associated with government directives, IPSP changes or as otherwise directed by the Board, projects and programs will be reprioritized driven by a reassessment of the risks prevailing at the time a change, addition or deferral is being considered.

e) Please see the response to d) above.

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

Interrogatory

Issue 2.1
Is the Load Forecast and Methodology appropriate and have the impacts of Conservation and Demand Management initiatives been suitably reflected?

Reference: ExhA/Tab14 /Sch3/AttachmentC /section1.0/4th bullet
Preamble: In the reference paragraph and elsewhere in this attachment C the term "natural conservation" is used.
Question: Please provide a definition of the term "natural conservation"

Response

Natural conservation pertains to energy savings that are expected to occur as a result of normal market forces (such as improved energy efficiency due to end-of-life equipment replacement) in the absence of intervention. Natural conservation is implicitly included in the load forecast before reduction of additional CDM impacts induced by Hydro One, the OPA or other government agencies.

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

Interrogatory

Issue 2.1
Is the Load Forecast and Methodology appropriate and have the impacts of Conservation and Demand Management initiatives been suitably reflected?

Reference: ExhA /Tab14 /Sch3 /Attachment C/ section3.1
Preamble: In the 4th paragraph, Hydro One is explaining the first method of evaluating the difference between 2004 and 2007 to measure the effect of CDM. "The economic growth between 2004 AND 2007 was removed using the historical relationship between the economic activity (i.e. GDP) and the peak load."
Question: Please provide information as to the quality of the correlation of GDP and peak load. How much error could be introduced in the estimate of CDM by the assumption that the relationship is certain?

Response

The correlation of GDP and peak load was calculated using the sectoral elasticities of load from the econometric models as presented in pages 1 to 7 of Appendix 2 in Exhibit A, Tab 14, Schedule 3. The high goodness of fit of the econometric equations and statistical significance of the estimated elasticities reflect a high degree of correlation between economic activity and load. Weighted by the share of load for each sector, the correlation of aggregate GDP and peak load is estimated to be 0.35 over the 2004-2007 period. Using this relationship, 621 MW is attributed to economic growth between 2004 and 2007. The standard error associated with the GDP elasticity is estimated to be 0.09 (or 155 MW), resulting in a range of 0.26 to 0.44 for the elasticity estimate, or a range of 466 MW to 776 MW attributed to economic growth. The 155 MW (plus or minus) is a good approximation of the maximum error that could be introduced in the estimate of the CDM.

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

Interrogatory

Issue 2.1
Is the Load Forecast and Methodology appropriate and have the impacts of Conservation and Demand Management initiatives been suitably reflected?

Reference: ExhA/Tab14/Sch3/AttachmentC/Appendix H /Conservation Culture
Preamble: In the paragraph before the last table it states: "By 2007, 56% of survey respondents said they used the LED holiday lights"
Question: Is the 56% a summation of the amounts in the first row, which totals 46%? If not please explain the how 56% is determined.

Response

The 56% is not a summation of the amounts in the first row. In the CDM survey, we have 1,480 customers responding to the question for LED holiday lights, for which 826 customers indicated responses for 2007. The 56% is percentage of 826 over 1480.

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

Interrogatory

Issue 2.2
Are other revenue (including export revenue) forecasts appropriate?

Reference: ExhE1/Tab1/Sched1/p.1
Preamble:
Table 1 indicates that the return on capital includes AFUDC recovery for the Niagara Reinforcement Project ($5.5 M in 2009 and $6.6 M in 2010)
Question:

a) Please explain why this adjustment is necessary.
b) Please provide the calculation to determine these amounts.
c) What is the status and schedule for completion of the Niagara Reinforcement Project?

Response

a) This adjustment for the Niagara Reinforcement Project allows for the recovery of carrying cost in the current period due to the delay in the project in-service date for reasons outside of the control of Hydro One. Approval for this treatment was received in the EB-2006-0501 OEB Decision with Reasons. As noted on pages 62-64 of the Decision, with respect to the Niagara Reinforcement Project, "…Hydro One faces carrying costs for these expenditures and the Board agrees with VECC and CCC that a compromise is appropriate. As CCC, VECC and SEC suggested, the Board has decided to allow Hydro One to expense – rather than capitalize – the AFUDC, or carrying costs, associated with the project based on the actual expenditures made to date."

b)

Test Year	Expenditures Made to Date ($M)	Cost Rate (%) *	Recovery of AFUDC
2009	99.1	5.59%	5.5
2010	99.1	6.69%	6.6

* Scotia Capital All-Corp mid-term yield

c) The status of the Niagara Reinforcement Project has not changed during the preceding year. It remains on hold with an uncertain scheduled date for completion as a result of the ongoing dispute between the governments of Ontario and Canada with the First Nations groups in the Caledonia area. Hydro One is not a party to this dispute. Once we confirm that Hydro One work crews have safe and unencumbered access to the work site, Hydro One will establish a schedule for completion of the work.

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

Interrogatory

Issue 2.2
Are other revenue (including export revenue) forecasts appropriate?

Reference: ExhE1/Tab1/Sched1/p.5
Preamble:
Table 4 at line 8 is a deduction of other cost charges. These cost charges are described as including deferred export credit refund, deferred tax refund and OEB cost adjustments offset by market ready cost recoveries.
Question:
Please provide a breakdown of the components that are included in the "other cost charges" category. Please provide any calculations showing how the other cost charges were determined.

Response

Below is the breakdown of the components included in other costs for the 2009 and 2010. The amount is $(13.5)M per year. For presentation purposes, the exhibit was rounded to $(14)M in 2009 and $(13)M in 2010. The result for the two years is $(27)M.

		Annualize	Annual Recovery/ (Refund)
Existing Deferral Account Recovery Details *as previously approved (EB-2006-0501)*			
Recovery of Market Ready Project			4.4
Refund of Export Credit Revenue			(13.2)
Regulatory Assets Requested for Approval Refer to EB-2008-0272 Exhibit F1, Tab 1, Schedule 1, table 2	June 30, 2009		
Refund of Tax Rate Changes	(13.9)	/48 mos x 12 mos	(3.5)
Refund of OEB Cost Assessment Differential	(4.2)	/48 mos x 12 mos	(1.1)
Refund of Pension Cost Differential	(0.2)	/48 mos x 12 mos	(0.1)
Total Other Cost Charges			**(13.5)**

Please refer to Exhibit I, Tab 1, Schedule 80 for calculations on regulatory assets requested for approval.

Ontario Energy Board (Board Staff) INTERROGATORY #16 List 1

Interrogatory

Issue 2.2
Are other revenue (including export revenue) forecasts appropriate?

Reference: ExhE1/Tab1/Sched1/p.6
Preamble:
Table 5 provides the components of change to the revenue requirement from the proposed 2009 to the proposed 2010. The change in load forecast accounts for $36 M of the total change.
Question:
Please provide a breakdown of the $36 M based on the categories shown in Table 4 of this Exhibit.

Response

The breakdown of the $36M based on the categories shown in Table 4 is as follows:

Line no.	Description	Change
1	OM&A	-
2	Depreciation	-
3	Capital Taxes	-
4	Income Taxes	12
5	Return	24
	Total Revenue Requirement	36
6	Deduct External Revenues	-
	Revenue Requirement less External Revenues	36
7	Deduct Export Revenue Credit	-
8	Deduct Other Cost Charges	-
9	Add Low Voltage Switch Gear	-
	Rates Revenue Requirement	36

Ontario Energy Board (Board Staff) INTERROGATORY #17 List 1

Interrogatory

Issue 2.2
Are other revenue (including export revenue) forecasts appropriate?
Board staff Question 17:
Reference: ExhE1/Tab1/Sched2/pp.2-5
Preamble:
Table 1 (External Revenues) projects a marked reduction in 2009 and 2010 Station Maintenance revenues and Engineering & Construction revenues. The reason given for the decline is the significant increase in Hydro One's Transmission work program and the reallocation of resources.
Question:

a) Has Hydro One implemented a reduction in resources dedicated to Station Maintenance and Engineering &Construction in the past? If so what were the reasons for the reduction and how was the resource reallocation managed.
b) Please provide details how Hydro One arrived at the 2009 and 2010 external revenues associated with Station Maintenance and Engineering & Construction.
c) Does Hydro One curtail its contracting in order to free up resources. Please explain how this is implemented.
d) Are there long-term contracts in place for any of the Station Maintenance and Engineering & construction work for which Hydro is committed through the test years? If so please provide details.

Response

a) In the past Hydro One has reduced its response to external work during times when resources were fully committed to internal work. As internal work programs are now much larger, response to external work will be low for the foreseeable future.

b) External work is driven by unsolicited customer requests which vary considerably as external business and economic conditions change. Hydro One uses trends from past years to predict external work requests. However, since internal resources are fully committed to work programs, the company has taken the strategic decision to only respond to requests that are required under the Transmission System Code, or those that involve work directly associated with its assets. Applying this strategy, results in the lower projections for the future external work presented.

   In addition, changes to the Transmission System Code have eliminated some types of external connection work on customer's assets which has also reduced the external revenue forecast.

c) Hydro One regularly receives unsolicited requests to bid on external work. Under our current strategy, any external requests that are not required under the Transmission System Code or directly associated with our own assets are not bid on

d) There are no long term commitments for external work contracts.

Ontario Energy Board (Board Staff) INTERROGATORY #18 List 1

Interrogatory

Issue 3.1
Are the proposed spending levels for Sustaining, Development and Operations OM&A in 2009 and 2010 appropriate, including consideration of factors such as of system reliability and asset condition?

Reference: Letters and e-mails sent, on the Board proceeding website.
Preamble: Numerous letters of comment have been received from the public and public organizations:
Questions:
Please provide Hydro One's response to each of the following letters received:
Letters of Comment:
a) P. LeMay; received November 12, 2008.
b) Mrs. Joan Richters; received November 12, 2008.
c) Senior Citizens Club #270, President Alene Charron; received November 4, 2008.
d) Marcel & Alene Charron; received November 4, 2008.
e) Judy Bernstein; received October 31, 2008.
f) Grant Bull; received November 3, 2008.
Request for Observer Status:
g) Frank Falconer; received October 2008.
h) Michael Hunter, received November 18, 2008

Response

It is not Hydro One's practice to respond individually to Letters of Comment and Requests for Observer Status. Hydro One does read each letter and notes the concerns expressed by the individuals or organizations. Hydro One notes that in certain cases, the concerns expressed are not directly related to issues that will be dealt with in this transmission application but nevertheless are of concern to Ontario electricity customers, especially those on a fixed income or suffering economic hardship.

This application requests only the funding necessary to meet customer needs, to ensure regulatory compliance, to meet safety and reliability standards and to support government initiatives.

Ontario Energy Board (Board Staff) INTERROGATORY #19 List 1

Interrogatory

Issue 3.1
Are the proposed spending levels for Sustaining, Development and Operations OM&A in 2009 and 2010 appropriate, including consideration of factors such as of system reliability and asset condition?

Reference: ExhC1/Tab1/Sched1/p4
Preamble: The pre-filed evidence states that "Labour costs are charged to OM&A and Capital work programs. The evidence contained at Exhibit C1, Tab 3 presents total staff levels and costs incurred by the Company..."
Question:

Total staff levels are not provided in the Exhibits cited. Please provide staff levels and labour costs in table format for historic years 2005, 2006, 2007, bridge year 2008 and test years 2009 and 2010. Please provide breakdown by MCP, PWU, Society and Total.

Response

Please refer to Attachment 1.

2005 ($)

REPRESENTATION	TOTAL NO. EMPLYS	TOTAL WAGES	Base Pay	Overtime Hours Worked	Overtime(Incl Premium)	Incentive	Other	Average Overtime Pay	Average Base Pay	Incentive as % of Base
PWU-Reg	2741	237,735,189	188,352,797	653,403	40,981,168	2,658,425	5,742,799	62.72	68,717	1.41%
SOCIETY-Reg	851	57,430,393	52,036,315	31,994	2,409,218	47,424	2,937,437	75.30	61,147	0.09%
MCP-Reg	312	41,021,983	32,331,641	1,926	144,251	5,676,201	2,869,889	74.88	103,627	17.56%
Total Regular	3,904	336,187,565	272,720,753	687,323	43,534,637	8,382,050	11,550,125	63.34	69,857	
PWU-Temp	58	1,876,779	1,745,586	3,186	158,682	2,610	-30,099	49.81	30,096	0.15%
SOCIETY-Temp	31	1,507,881	1,434,783	552	31,546	0	41,552	57.20	46,283	0.00%
MCP-Temp	10	315,086	305,778	92	3,507	0	5,800	38.08	30,578	0.00%
Total Temp	99	3,699,746	3,486,147	3,829	193,735	2,610	17,254	50.60		
CASUAL	1075	57,999,463	44,925,186	138,361	6,917,500	0	6,156,777	50.00	41,791	0.00%
TOTAL	**5,078**	**397,886,774**	**321,132,086**	**829,514**	**50,645,872**	**8,384,660**	**17,724,155**			

2006

REPRESENTATION	TOTAL NO. EMPLYS	TOTAL WAGES	Base Pay	Overtime Hours Worked	Overtime(Incl Premium)	Incentive	Other	Average Overtime Pay	Average Base Pay	Incentive as % of Base
PWU-Reg	2862	262,294,356	202,358,005	817,428	53,457,558	4,200	6,474,593	65.40	70,705	0.00%
SOCIETY-Reg	687	65,175,105	62,356,208	18,056	1,466,238	0	1,352,659	81.20	90,766	0.00%
MCP-Reg	469	59,489,433	49,471,987	703	55,767	4,397,964	5,563,716	79.33	105,484	8.89%
Total Regular	4,018	386,958,894	314,186,200	836,187	54,979,563	4,402,164	13,390,968	65.75	78,195	
PWU-Temp	110	2,509,937	2,582,255	1,869	111,845	0	-184,162	59.86	23,475	0.00%
SOCIETY-Temp	45	1,269,193	1,336,917	238	19,831	0	-87,555	83.50	29,709	0.00%
MCP-Temp	7	218,523	215,324	26	1,165	0	2,035	45.67	30,761	0.00%
Total Temp	162	3,997,654	4,134,495	2,132	132,840	0	-269,682	62.32		
CASUAL	1121	68,368,828	49,638,768	217,109	11,375,466	0	7,354,595	52.40	44,281	0.00%
TOTAL	**5,301**	**459,325,376**	**367,959,463**	**1,055,427**	**66,487,869**	**4,402,164**	**20,475,881**			

2007

REPRESENTATION	TOTAL NO. EMPLYS	TOTAL WAGES	Base Pay	Overtime Hours Worked	Overtime(Incl Premium)	Incentive	Other	Average Overtime Pay	Average Base Pay	Incentive as % of Base
PWU-Reg	3,084	276,571,977	226,331,027	720,131	48,126,236	500	2,114,215	66.83	73,389	0.00%
SOCIETY-Reg	712	67,398,484	65,268,684	29,059	2,332,197	6,500	-208,898	80.26	91,670	0.01%
MCP-Reg	516	67,420,494	56,665,378	800	63,511	6,636,752	4,054,852	79.44	109,817	11.71%
Total Regular	4,312	411,390,956	348,265,090	749,989	50,521,944	6,643,752	5,960,170	67.36	80,766	
PWU-Temp	143	2,826,419	3,116,973	1,060.25	50,825	0	-341,379	47.94	21,797	0.00%
SOCIETY-Temp	92	3,019,335	3,350,706	303.00	19,862	0	-351,234	65.55	36,421	0.00%
MCP-Temp	8	297,149	290,565	0.00	0	0	6,584	0.00	36,321	0.00%
Total Temp	243	6,142,903	6,758,244	1,363.25	70,687		-686,029	51.85	27,812	
CASUAL	1338	77,992,251	59,693,098	189,603	10,343,821	0.00	7,955,332	54.56	44,614	0.00%
TOTAL	**5,893**	**495,526,109**	**414,716,432**	**940,955**	**60,936,452**	**6,643,752**	**13,229,473**			

2008

REPRESENTATION	TOTAL NO. EMPLYS	TOTAL WAGES	Base Pay	Overtime Hours Worked	Overtime(Incl Premium)	Incentive	Other	Average Overtime Pay	Average Base Pay	Incentive as % of Base
PWU Reg	3,324	293,149,275	241,465,978	675,698	47,751,946.48		3,931,351	70.67	72,643	0.00%
SOCIETY Reg	961	89,830,612	87,904,906	38,118	2,314,148		-388,442	60.71	91,472	0.00%
MCP Reg	603	83,130,939	67,091,005			8,500,000	7,539,935		111,262	12.67%
Total Reg	4,888	466,110,826	396,461,889	713,816	50,066,094	8,500,000	11,082,843	70.14	81,109	
PWU Temp	245	4,194,042	4,778,399	1,060	50,431		-634,788	47.58	19,504	0.00%
Society Temp	95	2,650,372	3,283,778	251	19,709		-653,114	78.52	34,566	0.00%
MCP Temp	13	460,261	448,018				12,243		34,463	0.00%
Total Temp	353	7,304,675	8,510,194	1,311	70,140		-1,275,659	53.50	24,108	
CASUAL	1640	95,584,498	70,527,917	189,917	10,263,766		14,792,816		43,005	
TOTAL	**6881**	**569,000,000**	**475,500,000**	**905,044**	**60,400,000**	**8,500,000**	**24,600,000**		**69,103**	**0.00%**

2009

REPRESENTATION	TOTAL NO. EMPLYS	TOTAL WAGES	Base Pay	Overtime Hours Worked	Overtime(Incl Premium)	Incentive	Other	Average Overtime Pay	Average Base Pay	Incentive as % of Base
PWU Reg	3,373	300,145,964	246,658,589	678,826	49,412,196.28		4,075,179	72.79	73,127	0.00%
SOCIETY Reg	1,072	101,174,860	99,182,906	38,294	2,394,606.36		-402,653	62.53	92,521	0.00%
MCP Reg	625	87,181,260	70,565,477			8,800,000	7,815,783		112,905	12.47%
Total Reg	5,070	488,502,084	416,406,972	717,120	51,806,803	8,800,000	11,488,309	72.24	82,132	
PWU Temp	93	1,104,782	1,710,609	1,065	52,184.78		-658,012	49.00	18,394	0.00%
Society Temp	60	1,377,862	2,034,476	252	20,393.98		-677,008	80.88	33,908	0.00%
MCP Temp	5	181,699	169,008				12,691		33,802	0.00%
Total Temp	158	2,664,343	3,914,094	1,317	72,578.76		-1,322,329	55.11	24,773	0.00%
CASUAL	1692	98,033,573	72,078,934	190,796	10,620,618.60		15,334,020	55.66	42,600	0.00%
Total	**6920**	**589,200,000**	**492,400,000**	**914,370**	**62,500,000**	**8,800,000**	**25,500,000**			

2010

REPRESENTATION	TOTAL NO. EMPLYS	TOTAL WAGES	Base Pay	Overtime Hours Worked	Overtime(Incl Premium)	Incentive	Other	Average Overtime Pay	Average Base Pay	Incentive as % of Base
PWU Reg	3424	313,038,398	256,721,906	694,018	52,033,561		4,282,932	74.97	74,977	0.00%
SOCIETY Reg	1147	111,006,705	108,911,113	39,107	2,518,773		-423,180	64.41	94,953	0.00%
MCP Reg	628	90,329,523	72,815,291		0	9,300,000	8,214,232		115,948	12.77%
Total Reg	5199	514,374,626	438,448,309	733,125	54,552,334	9,300,000	12,073,983	74.41	84,333	2.12%
PWU Temp	70	665,436	1,302,103	1,088	54,891		-691,558	50.47	18,601	0.00%
Society Temp	25	174,459	864,530	258	21,451		-711,522	83.30	34,581	0.00%
MCP Temp	2	82,281	68,944		0		13,338		34,472	0.00%
Total Temp	97	922,176	2,235,576	1,345	76,342		-1,389,742	56.76	23,047	0.00%
CASUAL	1776	103,456,175	77,316,115	195,020	11,171,324		16,115,759	57.28	43,534	0.00%
Total	**7072**	**619,900,000**	**518,000,000**	**929,490**	**65,800,000**	**9,300,000**	**26,800,000**			

Note: Average Base Pay for Non-Regular employees are not meaningful because the period of employment could be significantly less than 1 year.
Other includes: Travel time, vacation bonus, unused vacation days paid out, standby allowance, shift allowances, vacation pay on termination, sick leave pay

Ontario Energy Board (Board Staff) INTERROGATORY #20 List 1

Interrogatory

Issue 3.1
Are the proposed spending levels for Sustaining, Development and Operations OM&A in 2009 and 2010 appropriate, including consideration of factors such as of system reliability and asset condition?

Reference: ExhC1/Tab2/Sched1/p2
Preamble: OM&A expenditure for 2009 is projected to increase by 8% over bridge year and OM&A expenditure for 2010 is projected to increase by 3% over 2009. Reasons noted are increasing maintenance of an aging and expanding transmission system.
Question:
How much of the increase in OM&A expenditure is due to aging and how much is due to expansion?

Response

The primary cause of the increase in OM&A is for sustainment programs related to aging infrastructure. The statement "aging and expanding transmission system" in this context is intended to highlight that OM&A costs are increasing not only because existing assets are getting older, but also because there are new assets being added to the system which also require some level of maintenance activities.

Ontario Energy Board (Board Staff) INTERROGATORY #21 List 1

Interrogatory

Issue 3.1
Are the proposed spending levels for Sustaining, Development and Operations OM&A in 2009 and 2010 appropriate, including consideration of factors such as of system reliability and asset condition?

Reference: ExhC1/Tab2/Sched1/p2

Preamble: OM&A spending in test year 2008 is listed as $402.7 million and is lower than OM&A spending in historic year. It is noted that the drop in spending is primarily due to small decreases on some station and line maintenance programs, however, there is no supporting rationale provided in Schedule 1 or Schedule 2.

Question:

a) Why did these decreases in station and line maintenance programs occur?
b) Could these factors be ongoing or could they reoccur?
c) What has been the proportion of sustaining planned work vs unplanned work for historical years? What is the forecast for planned work vs unplanned work for bridge and test years? *(VB)*

Response

a) The 2008 projected stations expenditures are lower by $3.3 million (or about 2%) when compared to 2007 actual expenditures. This is attributed to a lower 2008 projected spending on 750 MVA autotransformer remediation activities which is funded under the Power Equipment program. The 2007 spending on these remediation activities was higher than normal which is the primary reason for the difference between the 2008 projected spending and 2007 actual.

   The 2008 projected lines expenditures is lower by $2.8 million (or 6%) when compared to 2007 actual expenditures. This is attributed to a lower 2008 projected spending in vegetation management. The 2007 vegetation management spending was higher then normal which is the primary reason for the difference between the 2008 projected spending and 2007 actual. For details concerning the reason for the higher 2007 expenditures refer to interrogatory I-1-25 part a).

b) For 750 MVA autotransformer remediation activities, future costs in 2009 and 2010 are expected to be lower than 2007 but not as low as projected for 2008.

For vegetation management, future costs are expected to be lower than 2007 but not as low as projected for 2008. With overhead lines, costs are expected to increase after 2008.

c)

	2005	2006	2007	2008	2009	2010
Stations OM&A						
Planned	78%	73%	76%	73%	77%	78%
Unplanned	22%	27%	24%	27%	23%	22%
Lines OM&A						
Planned	82%	78%	84%	83%	85%	84%
Unplanned	18%	22%	16%	17%	15%	16%

Ontario Energy Board (Board Staff) INTERROGATORY #22 List 1

Interrogatory

Issue 3.1
Are the proposed spending levels for Sustaining, Development and Operations OM&A in 2009 and 2010 appropriate, including consideration of factors such as of system reliability and asset condition?

Reference: ExhC1/Tab2/Sched2/p5
Preamble: Increases in planned expenditures for stations OM&A are attributed to a large portion of the asset base moving through mid-life and a large portion of the asset base nearing end of life.
Question:
What are these portions of asset base moving through mid-life and end of life expressed as percent of asset base?

Response

The table below provides the portions of assets in the mid life and end of life regions for a number of station asset categories.

ASSET	% in Mid Life Region	% in End of Life Region
Power Transformers	58	23
Circuit Breakers	56	23
Grounding Grids	24	71
Batteries	50	16
High Pressure Air Systems	65	33
Chargers	22	47
Remote Terminal Units (RTU)	21	27

Ontario Energy Board (Board Staff) INTERROGATORY #23 List 1

Interrogatory

Issue 3.1
Are the proposed spending levels for Sustaining, Development and Operations OM&A in 2009 and 2010 appropriate, including consideration of factors such as of system reliability and asset condition?

Reference: ExhC1/Tab2/Sched2/p9
Preamble: Hydro One is currently evaluating the potential financial and operating impacts of new Federal government regulations related to management of PCBs.
Question:

a) When does Hydro One expect to complete the evaluation of the impact of the regulation?
b) As no funding has been allocated in the test years for any additional requirements stemming from the regulations, how does Hydro One propose to fund any environmental management that is required?

Response

a) Hydro One completed its evaluation of the financial impact of the new federal regulations governing the management of PCBs prior to filing its third quarter 2008 financial report.

   As a result of the new regulations, Hydro One Networks Transmission recorded an additional liability in its September 30, 2008 financial statements of approximately $106 million related to the estimated present value of additional future expenditures required to comply. As at September 30, 2008, the Transmission Business also recorded an equivalent increase in its PCB regulatory asset. The new expenditures include additional asset inspection, oil testing, disposal and destruction expenditures.

   The estimate to comply with the specific requirements of the regulations does not include other incremental future expenditures that are causally related to the regulations, such as such as replacement capital and other OM&A costs that are not directly related to compliance activities.

b) Hydro One expects program expenditures for PCB management will significantly increase starting in 2011. Hydro One will reflect any additional expenditures required in their next transmission rate application upon receipt of further Environmental Canada direction.

Ontario Energy Board (Board Staff) INTERROGATORY #24 List 1

Interrogatory

Issue 3.1
Are the proposed spending levels for Sustaining, Development and Operations OM&A in 2009 and 2010 appropriate, including consideration of factors such as of system reliability and asset condition?

Reference: ExhC1/Tab2/Sched2/p12
Preamble: Hydro One is continuing a program to re-commission dormant mechanical spill containment drainage sumps to allow the containment units to purge rainwater automatically thus reducing demands on station maintenance resources.

a) Please quantify the benefit in terms of reducing demands on stations maintenance resources.
b) Has Hydro One identified any other opportunities to reduce demands on station maintenance resources?

Response

a) The primary driver for this program is the fulfillment of Hydro One's mandate for environmental stewardship. A secondary benefit is the yearly cost savings associated with reducing the amount of contract services and station maintenance trouble call resources required to purge rainwater from the spill pits. The total amount of benefit that would be obtained depends on the amount of rain fall in each year. Over the past three years Hydro One has spent as little as $35,000 and as much as $75,000 per year to pump out rain water from mechanical spill containment drainage sumps at all Hydro One stations. The re-commissioning of mechanical spill containment drainage sumps at selected sites will not totally reduce these costs going forward.

b) Yes. An overview of Hydro One Transmission's efforts to improve cost efficiency in the past and initiatives being undertaken to continue improving cost efficiency in the future is provided in Exhibit A, Tab 16, Schedule 1. Opportunities with respect to the Cornerstone initiative are described in Exhibit D1, Tab 3, Schedule 7; Page 7, in lines 9 to 14 and on Page 11, lines 18 to 24.

Ontario Energy Board (Board Staff) INTERROGATORY #25 List 1

Interrogatory

Issue 3.1
Are the proposed spending levels for Sustaining, Development and Operations OM&A in 2009 and 2010 appropriate, including consideration of factors such as of system reliability and asset condition?

Reference: ExhC1/Tab2/Sched2/pp33-34
Preamble:
The OM&A associated with vegetation management is noted as $21.6 million (2006), $27.0 million (2007), $21.2 million (2008), $23.3 million (2009) and $24.6 million (2010).
Question:

a) Is the higher vegetation management cost in 2007 related to the requirements of the NERC Vegetation Management Standard that came into effect during 2006?
b) If so, is the proposed spending for 2009 and 2010 sufficient to meet the requirements of the standard?

Response

a) The new NERC Vegetation Management Standard did not have a direct impact on the higher costs during 2007, except in the area of condition patrols. Costs in this area were about $0.6 million greater than normal as Hydro One undertook a more extensive condition assessment program to better understand the condition of its rights of way and to protect against unforeseen vegetation events that would now have to be reported to NERC.

   Costs can vary from year to year depending on the number of urban projects, vegetation conditions and location. A number of factors contributed to the higher costs in 2007, including: a greater amount of the brush control required helicopters for personnel and equipment transport; Hydro One undertook clearing on a right of way in Mississauga where public opposition delayed work and required modifications to the plan in order to gain community acceptance; a right of way in the Ottawa area required further clearing to prevent vegetation from encroaching into the lines in order to guarantee reliability.

b) Yes the spending proposed for 2009 and 2010 is expected to be sufficient to meet the requirements of the standard.

Ontario Energy Board (Board Staff) INTERROGATORY #26 List 1

Interrogatory

Issue 3.1
Are the proposed spending levels for Sustaining, Development and Operations OM&A in 2009 and 2010 appropriate, including consideration of factors such as of system reliability and asset condition?

Reference: ExhC1/Tab2/Sched2/p40
Preamble: The OM&A associated with preventative maintenance and asset condition assessment for overhead lines for bridge year 2008 does not align with historic and test years. The 2008 expenditure is lower than 2007.
Question:

a) As much of this work consists of regularly scheduled activities, were some activities not completed in 2008?
b) If so, could this affect reliability and increase unplanned maintenance?

Response

a) No. It is expected that all regularly scheduled activities will be completed during 2008 as planned. The level of preventative maintenance and asset condition assessment activities completed from year to year may vary depending on need and priorities. An increased emphasis on insulator testing conducted during 2007 is responsible for the 7% difference between 2007 expenditures and the 2008 projection.

b) As noted in part a), it is expected that all regularly scheduled activities will be completed during 2008 as planned. Therefore there is no adverse impact on reliability or unplanned maintenance.

Ontario Energy Board (Board Staff) INTERROGATORY #27 List 1

Interrogatory

Issue 3.1
Are the proposed spending levels for Sustaining, Development and Operations OM&A in 2009 and 2010 appropriate, including consideration of factors such as of system reliability and asset condition?

Reference: ExhC1/Tab2/Sched3/p2
Preamble: Development OM&A as a percentage of total OM&A has generally increased each year from 2.0% in 2005 to 3.6% in 2010.
Question:

a) Please explain the drivers for this increasing percentage.
b) Is there an industry standard for development OM&A as a percentage of total OM&A? If so, how does Hydro One compare?

Response

a) The main drivers for the increasing percentage are to carry out the research and development (R&D) and standards development required to address the following emerging issues and utility challenges:

- Improve asset performance and optimization associated with an aging asset infrastructure.
- Heightened security, protection and regulatory compliance requirements (e.g. new NERC and NPCC standards).
- Incorporation of new and advanced technologies that will be applied for the first time on the Hydro One system (e.g. static var compensators, series capacitors, "smart" digital protections, controls, monitoring and communication systems)
- Incorporation of significant renewable and distributed energy supply sources, including grid energy storage devices.
- Need for skilled and trained power system engineering resources.

Hydro One also awards research and development work to universities with a focus on Hydro One's business. Also, university chair positions and adjunct professorships are being funded to support the power systems engineering curriculum to deliver the skills and resources needed by Hydro One in the future.

b) No. Hydro One is not aware of any industry standard for development OM&A as a percentage of total OM&A

Ontario Energy Board (Board Staff) INTERROGATORY #28 List 1

Interrogatory

Issue 3.1
Are the proposed spending levels for Sustaining, Development and Operations OM&A in 2009 and 2010 appropriate, including consideration of factors such as of system reliability and asset condition?

Reference: ExhC1/Tab2/Sched3/pp5-7
Preamble: Hydro One is performing pre-engineering development OM&A for future projects related to the IPSP and other long term projects. Hydro One is not seeking to recover the costs of this work in the current proceeding.
Question:
Will the scope of the projects and the cash flow per year change given the September 17, 2008 Ministerial Directive and the adjournment of the IPSP hearing?

Response

At this time, Hydro One does not know what changes, if any, may be made to the scope of the referenced projects or their cashflows as a result of the September 17, 2008, Ministerial Directive to the OPA and the subsequent adjournment of the IPSP hearing.

<u>Ontario Energy Board (Board Staff) INTERROGATORY #29 List 1</u>

Interrogatory

Issue 3.1
Are the proposed spending levels for Sustaining, Development and Operations OM&A in 2009 and 2010 appropriate, including consideration of factors such as of system reliability and asset condition?

Reference: ExhC1/Tab2/Sched4/p3
Preamble: The pre-filed evidence states that, "Planned expenditures for Operations OM&A test years are higher than bridge and historical years due to increased operator training requirements, increased operating facilities maintenance and monitoring requirements, and labour and material escalation."
Question:
Please provide a table outlining expenditures for operator training, operating facilities maintenance and monitoring requirements, and labour and material escalation for historic, bridge and test years.

Response

A Table showing the historic, bridge and test years operator training costs and the cost of operating facilities maintenance and monitoring is provided below:

(All figures $M)

Description	Historic Years			Bridge Year	Test Years	
	2005	2006	2007	2008	2009	2010
Operator Training Costs	0.7	2.5	3.1	4.2	5.0	4.1
Operating Facilities Maintenance & Monitoring	6.6	6.8	7.5	7.0	8.5	8.4

The inflationary increases from 2005 to 2010 are described in Exhibit A, Tab 14, Schedule 2. Over the 2005 to 2010 period, the composite wage and material escalation for transmission O&M is estimated to be about 13%.

Ontario Energy Board (Board Staff) INTERROGATORY #30 List 1

Interrogatory

3. OM&A

Reference:

a) ExhC1/Tab2/Sched1/ p2/ sec2/lines22

b) ExhC1/Tab2/Sched 2/p3/line6

Preamble:

There are numerous instances in the section on Sustainment OM&A where reliability and/or asset condition is referred to as a driver for investment. For example, reference a) refers to the Sustaining OM&A budget representing investments intended to ensure that "… the overall reliability of the system is maintained." Reference b) refers to reduced reliability of supply to customers as a factor in Sustaining OM&A expenditure in the area of Power Equipment.

Questions:

For the sustainment category of **OM&A** expenditure please provide information on how **system reliability and asset condition** metrics are factored into the OM&A investment decision. The information should be provided to the level of detail so that particular instances of inadequate reliability performance or asset condition can be related to specific investments.

Response

System reliability and asset condition are just two of the factors considered in making investment decisions for Sustaining OM&A, as described in Section 2 of Exhibit A1, Tab 14, Schedule 4. All the factors taken into consideration in developing each category of Station and Lines investments are specifically detailed in the "Investment Plan Process" sections of Exhibit C1, Tab 2, Schedule 2. These sections include the extent to which reliability and asset condition are a driver for a particular investment category.

Details for specific programs are provided in the table below.

Program	Investment Drivers		
	Reliability	Condition Assessments	Other Factors
750 MVA Transformer Remediation	• Three failures of 750 MVA transformers since 2003	• Oil test results show high water content which can contribute to insulation system breakdowns • DGA results show overheating within the main tanks, bushing shields and tap changers	• Manufacturer's design review used to define remediation. • Specific maintenance and design deficiencies determined to exist.
Power Transformer Remediation	• Failure histories of specific classes of transformers • Identification of specific failure modes	• Oil sampling reveals insulating fluid and insulation is contaminated with high moisture content, acids or high particulate content • DGA results show overheating within the main tanks and tap changers. • Deterioration of transformer cooling radiators or other components. • Oil leaks and excessive vibrations.	
Gas Insulated Switchgear (GIS) Refurbishment Programs	• Forced outage rate for GIS breakers is ~3 times worse than total system average for breakers • The unavailability per occurrence for these breakers is ~2 times worse than total system average for breakers.	• Excessive hydraulic pump run time • Hydraulic leaks • Excessive SF6 leak rates • Seal deterioration • Metal in hydraulic fluid	• Seal deterioration a known problem. • Manufacturer recommended refurbishment after 20 year of operation
Air Blast Circuit Breakers (ABCBs)	• Forced outage rate for ABCBs is ~3.5 times worse than total system average for breakers	• O-rings and seals have deteriorated to such an extent that breakers will leak air resulting in an increased risk of failure	• Manufacturer recommends regasketing and rebuilding mid-way through ABCBs 40-year life
Overhead Lines Preventative Maintenance and Condition Assessments	• Outages due to salt contamination • 10 to 15 wood arm failures per year on 230 kV and 115 kV systems • About 12 defective insulator strings failures per year • About 2 shieldwire failures per year	• Helicopter inspections have identified end of life wood crossarms and other defects • Number and type of defects found during regular patrols can influence asset condition assessment expenditures and schedule • Thermovision patrols identify 65 to 200 overheated connectors on an annual basis	• Regularly scheduled inspection activities are carried out to ensure safety as these line facilities are located in the public domain

Program	Investment Drivers		
	Reliability	Condition Assessments	Other Factors
Planned Lines Corrective	• Two conductor breaks over the last 5 years • Two 500 kV tower foundation failures over the last five years	• Deteriorating conductor condition caused by metal fatigue due to wind induced vibration • 500 kV anchors and foundations found to be extensively corroded	
Vegetation Management	• 7 to 11 tree related outages per year	• Condition patrols to identify and remove danger trees, as well as assess duration until vegetation growth will infringe on clearance standards	• Rights-of-Way maintained about every 7 years, on average

Ontario Energy Board (Board Staff) INTERROGATORY #31 List 1

Interrogatory

Issue 3.2
Are the proposed spending levels for Shared Services and Other OM&A in 2009 and 2010 appropriate?

Reference: ExhC1/Tab2/Sched6/p13
Preamble: Hydro One notes that the Human Resources Function will play a significant role in the demographic transition. "Approximately 25 percent of the workforce (>1000 employees) has become or will be eligible to retire in the next 1½ years. Hydro One must not only replace these people, but also find an additional 600 people to meet the need of the planned work programs."
Question:

a) Please provide planned work program information that supports the additional 600 people.
b) Will the additional 600 people be full time employees or will some be contract staff?

Response

Incorrect figures were inadvertently provided in the referenced exhibit. The above quote should be corrected as follows:

"Approximately 25 percent of the current workforce (about 1000 employees) has become or will be eligible to retire by ***December 31, 2008. Approximately 30 percent of the current workforce (about 1300 employees) will be eligible to retire by December 31, 2010.*** Hydro One must not only replace these people, but also find ***approximately 300*** additional people to meet the need of the planned work programs."

Hydro One Networks has an integrated workforce for its Transmission and Distribution businesses. This allows Hydro One to take advantage of economies of scale and efficiencies that would not be available through separate transmission and distribution operations. The approximately 300 staff are required for increased work program demands in both the Transmission and Distribution businesses. As EB-2008-0272 is a cost of service application for Hydro One's Transmission business, the work program requirements and related staffing needs for its Distribution business are not within scope of this hearing. A full discussion of Networks Distribution Business work program requirements are provided in evidence submitted before the OEB in EB-2007-0681 and EB-2008-0187.

a) The planned work program information for the Transmission Business that supports the need for additional staff is provided within schedules contained in Exhibit C1, Tab 3, which discusses the Transmission OM&A program, and Exhibit D1, Tab 3, which discusses the Transmission Capital Expenditures. Both the OM&A and Capital Expenditures work programs show increases in 2009 and 2010 as compared to 2008. A significant driver for the needed additional staff is the larger Development capital program, which more than doubles between 2008 and 2010. Additional staff, such as Protection Engineers, Control Engineers, Project Managers, Telecom Engineers, Protection and Control CADD (Computer Aided Design & Drafting) Technicians, Telecom CADD Technicians and Power Equipment Engineers, are needed to work on projects such as Woodstock Area Transmission Reinforcement; installation of Static Var Compensators at Nanticoke, Detweiler, Mississagi, Lakehead and the Northeast; and the new Bruce to Milton Transmission Line.

Through this period, Hydro One will get more work done with proportionally fewer regular staff. A broader discussion of the work program increase between 2008 and 2010 is provided in Exhibit I, Tab 1, Schedule 44.

When combined with increased resource needs to support our Distribution Business, the cumulative impact is an increase of about 300 staff.

b) The 300 staff will be regular employees. Contract and temporary staff will also be economically utilized as required. For a full discussion of increased use of contract and temporary staff please refer to Exhibit I, Tab 1, Schedule 44, part a).

Ontario Energy Board (Board Staff) INTERROGATORY #32 List 1

Interrogatory

Issue 3.2
Are the proposed spending levels for Shared Services and Other OM&A in 2009 and 2010 appropriate?

Reference: ExhC1/Tab2/Sched6/p18
Preamble: General Counsel and Secretary Function costs in bridge year 2008 is listed as $7.3 million and is lower than costs in historic year 2007, which are listed as $7.9 million.
Question:
Please provide the rationale for the decrease in 2008.

Response

Shared services General Counsel and Secretary Function costs have decreased by $0.6 million from 2007 to 2008. This is the result of more costs being charged to work programs and projects and an increased use of internal legal resources which lessens the reliance on outside legal counsel.

Ontario Energy Board (Board Staff) INTERROGATORY #33 List 1

Interrogatory

Issue 3.2
Are the proposed spending levels for Shared Services and Other OM&A in 2009 and 2010 appropriate?

Reference: ExhC1/Tab2/Sched8/p4
Preamble: Asset Management costs in bridge year 2008 increased by 28% 2007. Some examples provided of work contributing to the increase are IPSP, CDM, smart meters and compliance activities (NERC, NPCC, SEC, OSC, Bill 198) and the Cornerstone initiative.

a) Please identify if any of the costs are one-time costs.
b) If any of the costs are one-time costs, please explain the level of asset management costs in 2009 and 2010.

Response

a) Asset Management costs are experiencing upward pressures due to the requirements of such initiatives as IPSP, CDM and smart meters, compliance activities (such as NERC, NPCC, SEC, OSC, Bill 198) and the Cornerstone initiative. This is largely work of an ongoing nature – not one-time expenditures – and not restricted to 2008.

Increased work has been required, for example, to help the organization comply with mandatory NERC and NPCC standards, which are rapidly expanding in number and detail. Hydro One's obligation to comply with NERC Standards, NPCC Regional Standards and NPCC Criteria is stated in the IESO Market Rules (Chapter 5, "Power System Reliability"). The new reliability standards that NERC has adopted and are applicable to Hydro One include, but are not limited to Analysis and Mitigation of Protection System Misoperations; Protection System Maintenance and Testing; Special Protection System Data and Documentation; Special Protection System Assessment; Special Protection System Maintenance and Testing; Methodology, Documentation and Communication of Facility Ratings; Critical Infrastructure Security, etc. As each new standard becomes effective in the Province of Ontario, Hydro One is required to comply. Revisions to internal governance documentation such as policies, directives and operating instructions are among the changes needed to align with the requirements of the new standards.

In addition, Hydro One provides guidance, influence and support to the Standards Development initiatives through participation on various NERC Committees and drafting teams and on NPCC Committees and technical task forces. Hydro One must review and submit comments to the proposed drafts for NERC Standards and NPCC Regional Standards, Directories and Criteria. For example, the NERC Business Plan for 2009 alone includes a total of 29 projects involving a total of 145 standards (review of existing or development of new standards).

Bill 198 requirements include a sign off process that provides for process owners to sign-off on a quarterly basis, and for Directors and VPs to sign-off on a semi-annual basis. Other activities that need to be done to comply with Bill 198 include reviewing process documentation for accuracy and completeness, and updating documentation as required, testing key controls in conjunction with members of the Bill 198 team, providing evidence of effective operation of controls, responding to follow-up questions, reviewing test results, etc. All of these impose additional requirements on Asset Management, and are ongoing, rather than one-time costs.

The Smart Meters project is a substantial incremental undertaking being managed by Asset Management; this project runs over a series of years (currently planned until 2011). As well, the Cornerstone initiative is a multi-phase, multi-year project and requires incremental investment in Asset Management to prepare for and transition to the new Cornerstone suite of systems and processes.

Included in the list of initiatives above should be compliance with International Financial Reporting Standards (IFRS). Although this project is being spearheaded by Corporate Finance, there are implications for Asset Management, such as impacts on the determination of labour rates, on business planning and on asset accounting. Activity within Asset Management to ensure compliance with IFRS is ramping up in 2008 but will continue through to at least 2011.

b) Not Applicable

Ontario Energy Board (Board Staff) INTERROGATORY #34 List 1

Interrogatory

Issue 3.2
Are the proposed spending levels for Shared Services and Other OM&A in 2009 and 2010 appropriate?

Reference: ExhC1/Tab2/Sched8/p8
Preamble: System Investment costs have more than doubled in the period 2005 to 2008 and further increases are projected for test years. One of the reasons cited is an unprecedented number of requests for generation applications requiring connection impact assessments.
Question:

The system investment cost allocation to transmission is 76%. Is this appropriate given the high volume of requests for connection impact assessments to the distribution system?

Response

System Investment is responsible for developing, scoping and obtaining approvals for work related to both transmission and distribution. As mentioned in Exhibit C1, Tab 2, Schedule 8, there has been upward pressure on costs due to a number of factors, one of which is an increased number of generation applications requiring connection impact assessments.

The allocation percentage utilized for System Investment was determined through the time allocation study completed for Hydro One's application for 2007/2008 transmission rates (EB-2006-0501), and utilizing the R.J. Rudden Associates methodology approved by the OEB. In 2008, Black & Veatch Corporation (formerly R.J. Rudden) was engaged to review the common corporate cost allocation and the 2008 Asset Management Time Study to assess the reasonableness of the cost allocation methodology used for the 2009 and 2010 test years. B&V concluded that the 2008 Asset Management Time Study results were "reasonably similar" to the March 2003 and April 2006 study results and that the results "reflect a cost-based distribution of the costs of providing the CCFS" (Exhibit C1, Tab 5, Schedule 1, Attachment 1). Thus, Hydro One believes that the System Investment allocation to transmission is adhering to the OEB approved methodology.

Ontario Energy Board (Board Staff) INTERROGATORY #35 List 1

Interrogatory

Issue 3.2
Are the proposed spending levels for Shared Services and Other OM&A in 2009 and 2010 appropriate?

Reference: ExhC1/Tab2/Sched9/p15
Preamble: Business Telecom OM&A expenditures in 2008 are 18.6% higher than 2007 costs. The "increases from 2008 reflect increase in services for the increased size of the Hydro One workforce, the increase in costs for services provided by Hydro One Telecom and in 2009 the costs associated with the renewal of the Bell contract"
Question:

a) What proportion of the 18.6% increase is associated with the increased size of the Hydro One workforce?
b) Provide a table summarizing the Hydro One workforce, and the transmission business workforce for historic, bridge and test years.

Response

a) Hydro One has assumed that Board Staff is requesting comparative information on 2009 and 2008 Telecom expenditures versus the 2008 and 2007 referred to in the question.

Out of total increase of $3.2 million which occurs between 2008 and 2009, $1.1 million can be attributed to an increase in workforce. The workforce increase relates to Hydro One staff, Inergi and Vertex staff, contractors and 3rd party consultants who support Hydro One business processes and projects. A portion of the increase in data network services (total $0.3 million) is related to the establishment of 2 new work sites which could also be considered as resulting from the increased workforce and an expanded work program.

Further information relating to this question can be found in interrogatory response at Exhibit I, Tab 4, Schedule 20.

b) Please refer to Exhibit I, Tab 1, Schedule 19 for Hydro One work force numbers.

Hydro One has an integrated workforce for its transmission and distribution businesses. This allows Hydro One to take advantage of economies of scale and efficiencies that would not be available through separate transmission and distribution operations. As a result of its integrated workforce, separate workforce data for Hydro One's Transmission Business only is not available.

Ontario Energy Board (Board Staff) INTERROGATORY #36 List 1

Interrogatory

3. OM&A

Issue 3.2
Are the proposed spending levels for Shared Services and Other OM&A in 2009 and 2010 appropriate?

Board staff Question 36:
Reference: ExhC1/Tab2/Sched12/p6
Preamble: Rights payments associated with individual railways are being consolidated into master agreements with each individual railway. The pre-filed evidences states that, "This type of agreement will result in one annual payment per railway, reducing administrative efforts and should streamline the payment process."
Question:
a) Can Hydro One quantify the benefit of reducing administrative effort?
b) Are there other similar opportunities?

Response

a) Minor administration efficiencies will be realized with the implementation of this consolidation of payments, as agreements are reached with the railway companies.

b) There are opportunities for consolidation of real estate crossing or occupation payments with Railway Companies.

Ontario Energy Board (Board Staff) INTERROGATORY #37 List 1

Interrogatory

3. OM&A

Issue 3.2
Are the proposed spending levels for Shared Services and Other OM&A in 2009 and 2010 appropriate?

Board staff Question 37:
Reference: ExhC1/Tab5/Sched1/p2
ExhC1/Tab5/Sched1/Attachment1/p6
Preamble: The Rudden methodology for common corporate cost allocation was approved for 2007/2008 Transmission Rates filing. The consistency in the use of the cost allocation methodology for 2009 and 2010 has been reviewed by Rudden (now Black & Veatch).
Question:
Please explain the difference in the allocation of 2009 CCF&S Costs between the two references.

Response

The amount shown in Table 1 of Exhibit C1, Tab 5, Schedule 1, page 2 of Total CCF&S Costs of $96.0M is a component of the $274.1M Total CCFS Costs as shown in Table 2 in Exhibit C1, Tab 5, Schedule 1, Attachment 1, page 6.

The table below reconciles the amounts used in the two references.

2009 ($ Millions)	Total	Transmission	Distribution	Others
Total CCF&S Costs [as per Table 1 (ExhC1/Tab5/Sch1/p.2)]	96.0	47.5	46.0	2.5
Inergi	105.3	26.2	77.9	1.1
Other Common Corporate Costs (e.g. Telecom, IMIT, Supply Chain Services)	72.8	21.3	16.6	34.8
Total CCFS Costs [as per Table 2 (Exh C1/Tab5/Sch1/Attach1/p6)]	**274.1**	**95.1**	**140.5**	**38.5**

Ontario Energy Board (Board Staff) INTERROGATORY #38 List 1

Interrogatory

Issue 3.2
Are the proposed spending levels for Shared Services and Other OM&A in 2009 and 2010 appropriate?

Board staff Question 38:
Reference: ExhC1/Tab5/Sched3/p3
Reference: ExhC1/Tab5/Sched3/Attachment1/p3
Preamble: The 2009-2010 common asset allocation using the Rudden (now Black & Veatch) methodology.
Question:
Why do the allocations, as at December 31, 2007, in the two references differ by $2 million?

Response

The allocation differs because Hydro One uses the OEB approved Black and Veatch (Rudden) Common Asset Allocation methodology to allocate Common Assets at the Major, Minor and Transportation & Work Equipment "TWE" (Minor) asset group level. The Rudden "Review of Common Assets Allocation – 2008" filed in Exhibit C1, Tab 5, Schedule 3, Attachment 1, page 3 conducted its review at a level below that at which Hydro One allocates the Common Assets of Hydro One to Transmission and Distribution operations. The Review shows the differences resulting from these sub-grouping allocations and the impact these sub-grouping allocation contributed to the $1.9 million difference between the $258.0 million Transmission amount as shown in Table 1 of Exhibit C1, Tab 5, Schedule 3 and the $256.1 million Transmission amount as shown in Table 1 on page 3 of Exhibit C1, Tab 5, Schedule 3, Attachment 1.

In reference to the Rudden review, the following should be noted:

> "*B&V's objective in allocating the December 2007 Common Assets was to ensure that the allocation was reasonable and was consistent with the allocation of the costs of the common corporate functions and services, as discussed in our Review of Implementation of Common Costs Methodology – 2008 dated September 10, 2008 ("2008 Common Costs Report")". [Reference: Exhibit C1, Tab 5, Schedule 1 – Attachment 1, page 1]*

> And the conclusion noted in the Rudden review:
> *Based on the work B&V performed 38% is a reasonable composite allocation of common asset costs to Transmission for Hydro One Networks'*

2009 / 2010 Transmission Rates filing. That percentage reflects the results of the OEB-accepted methodology and is consistent with prior results.” [Reference: Exhibit C1, Tab 5, Schedule 1 – Attachment 1, page 4]

Ontario Energy Board (Board Staff) INTERROGATORY #39 List 1

Interrogatory

Issue 3.3
Are the compensation levels proposed for 2009 and 2010 appropriate?

Reference: ExhC1/Tab3/Sched1/p1
Preamble: Hydro One notes that 1,000 Networks staff (transmission and distribution) are eligible for undiscounted retirement by December 31, 2008. The pre-filed evidence states that a greater number of staff eligible to retire will elect to retire sooner given the increased competition for these scarce resources in the marketplace.
Question:

a) What proportion of staff eligible to retire by December 31, 2008 has filed notice that they will retire?
b) Is Hydro One able to forecast retirements with respect to competition for resources as well as the current economic climate?

Response

a) As of the end of 3rd quarter 2008, 116 employees have retired or terminated (eligible to retire with undiscounted pension but elected to remove some or all of pension from the Plan). This represents 12.2% of those who were eligible to retire in 2008.

b) Hydro One is not able to forecast retirements with respect to competition for resources as well as the current economic climate.

However, experience has shown that Hydro One employees have retired and have joined various utilities, academic institutions and other companies across Canada such as OPG, OPA, IESO and Wardrop.

The current economic climate is too recent to assess any specific impact upon retirement trends. However, with a defined benefit pension plan, it is not anticipated that there will be a significant impact upon Hydro One retirement rates. With a defined benefit pension plan, employees are shielded from the impact of an economic downturn and the decision to retire is then primarily based upon personal choice and behaviour.

As noted in evidence (Exhibit C1, Tab 3, Schedule 1, page 1), recent studies suggest that up to half the workforce in the North American electricity industry will be eligible for retirement in the next five years. By December 31, 2010, over 30% of current Hydro One staff will be eligible to retire. In light of these facts, the electrical utility sector still anticipates that there is a critical shortage of engineers and trades employees in 2008 and beyond.

Ontario Energy Board (Board Staff) INTERROGATORY #40 List 1

Interrogatory

Issue 3.3
Are the compensation levels proposed for 2009 and 2010 appropriate?

Reference: ExhC1/Tab3/Sched1/p5
Preamble: Hydro One is active in developing current staff to enhance and/or develop new skills.
Question:
a) Please quantify the benefits of this training?
b) Does Hydro One expect productivity to increase when skills are enhanced and new skills are developed?

Response

a) It is very difficult to quantify with any precision the benefits of training.

Training is core to any well run business. Hydro One views training as an investment. Hydro One invests up front to train our staff which will lead to benefits in the future by enabling returns in the form of increased and improved knowledge, skills, capability and productivity.

The ultimate benefit of training is for employees to work safely, productively and to be able to successfully adapt to change. Research also shows that an employer's willingness to develop employees is a causal factor to their level of engagement. As noted in evidence (Exhibit C1, Tab 3, Schedule 1, page 6), employee engagement influences how hard they work, and how long they stay with an employer. Engaged employees provide greater discretionary effort which often leads to increased productivity.

b) See part a) above. Hydro One does anticipate that productivity will increase as new and enhanced employee skills are developed. As discussed in Exhibit A, Tab 16, Schedule 1, page 7, the hiring of new staff and the associated training is part of the business transformation benefits that will be accrued from hiring and training new staff.

It is reasonable to assume that productivity will increase as new and enhanced skills are developed. It is also important to recognize that there are other potential influences on productivity, for example, work force engagement, efficient and effective management systems, availability of tools and equipment etc.

Ontario Energy Board (Board Staff) INTERROGATORY #41 List 1

Interrogatory

Issue 3.3
Are the compensation levels proposed for 2009 and 2010 appropriate?

Reference: ExhC1/Tab3/Sched2/p1
Preamble: Following the division of Ontario Hydro, Hydro One inherited collective agreements that already establish terms and conditions of employment for represented employees.
Request:

Please provide comparison of compensation, wages and benefits with other Ontario Hydro successor companies. Please provide the comparison for historic, bridge and test years.

Response

Access to historical compensation and benefits information amongst the successor companies is limited. Wage data can be gathered from publicly available collective agreement information. However, pension and benefit information is not publicly accessible.

Ontario Power Generation and Bruce Power both participated in the Mercer/ Oliver Wyman Compensation Cost Benchmarking Study provided in Exhibit A, Tab 16, Schedule 2, Attachment 1. However, due to participant confidentiality reasons, Hydro One is not privy to specific OPG or Bruce Power data.

As discussed in Exhibit C1, Tab 3, Schedule 2, page 1, Hydro One inherited collective agreements from Ontario Hydro. The numerous cost and productivity improvements negotiated with the Hydro One unions are discussed in Exhibit C1, Tab 3, Schedule 2, pages 7 to 9. In addition, Hydro One has restrained wage escalation when compared to successor Ontario Hydro employers.

This is illustrated in the following wage scale comparison tables. In all cases (both PWU and Society positions), wage scales based on salary schedules are provided, rather than average actual paid wages, as only the former is publicly available. Note that specific PWU positions in IESO, OPG and Bruce Power were examined as they are comparable to Hydro One positions and have a significant number of employees in those positions. OPA is not included in these comparisons as it is our understanding that they do not have PWU or Society represented staff.

Power Workers' Union – Wage Scale Comparisons, 1999 and 2008

	1999	**2008**	**Percent Change**
Mechanical Maintainer/Regional Maintainer - Mechanical			
Hydro One [29 employees]	$ 28.23	$ 37.18	32%
OPG	$ 29.08	$ 43.42	49%
Bruce Power	$ 29.08	$ 49.25	69%
Shift Control Technician/Regional Maintainer - Electrical			
Hydro One [145 employees]	$ 28.23	$ 37.18	32%
OPG	$ 30.31	$ 43.42	43%
Bruce Power	$ 30.31	$ 49.40	63%
Clerical – Grade 56 (based on 35-hour work week)			
Hydro One [32 employees]	$ 21.46	$ 28.27	32%
OPG	$ 21.46	$ 27.73	29%
Bruce Power	$ 21.46	$ 30.70	43%
IESO	$ 21.46	$ 27.60	29%
Clerical – Grade 58 (based on 35-hour work week)			
Hydro One [36 employees]	$ 24.20	$ 31.88	32%
OPG	$ 24.20	$ 33.78	40%
Bruce Power	$ 24.20	$ 34.61	43%
IESO	$ 24.20	$ 31.11	29%

Note: The wages in the table do not reflect the following incentives/bonuses:

Hydro One – No incentives or bonuses are paid.

OPG – In 2002, OPG introduced Skill Broadening, which led to eligible employees receiving a $1,000 lump sum, as well as a wage increase of 5% (in addition to the general wage increase of 2% for that year). For year end 2006, the average cost was $1,500 for incentives

Bruce Power - Variety of bonuses such as vacation bonus, fitness bonus, instructor bonus, etc. In 2003, Bruce Power implemented a competency-based progression plan, which provided up to a 12% increase for journeypersons and a 6% increase for supervisors. Bruce Power has also introduced Multi Trade rates for certain classifications, which are higher than the competency-based rates. In 2005 and 2006, Bruce Power gave special increases to specified job classifications.

Society of Energy Professional – Wage Scale Comparisons 1999 and 2008

	1999	**2008**	**Percent Change**
MP2			
Hydro One	$77,954.79	$88,025.25	13%
OPG	$77,954.79	$89,345.73	15%
Bruce Power	$77,954.79	$88,025.25	13%
IESO	$77,954.79	$103,324.00	33%
MP4			
Hydro One	$88,651.39	$100,078.50	13%
OPG	$88,651.39	$101,547.12	15%
Bruce Power	$88,651.39	$100,078.50	13%
IESO	$88,651.39	$117,468.00	33%
MP6			
Hydro One	$100,756.80	$113,801.46	13%
OPG	$100,756.80	$115,459.72	15%
Bruce Power	$100,756.80	$113,801.46	13%
IESO	$100,756.80	$133,588.00	33%

Note: the above does not reflect that the following incentives/bonuses are now paid out:

Hydro One – no incentives or bonuses are paid

OPG – Pays a number of bonuses for supervision, specialized work, training/certification and retention. For year end 2006, the average cost was $2,400 for incentives.

Bruce Power - Pays a number of bonuses for supervision, specialized work, training/certification and retention. Also has a bonus plan for 2007, 2008 and 2009, which, if Company targets are met, pays 2% for MP2 and MP3, 4% for MP5 and MP5, 6% for MP6 (additional 1% available if stretch targets met).

2007 CEO Compensation

Position	Hydro One	OPG	OPA	IESO
CEO	$794, 299	$1,788,719.42	$650,727.50	$494,197.63

Ontario Energy Board (Board Staff) INTERROGATORY #42 List 1

Interrogatory

Issue 3.3
Are the compensation levels proposed for 2009 and 2010 appropriate?

Reference: ExhC1/Tab3/Sched2/p10
Preamble: The year end Hydro One Networks Inc. Payroll is summarized for the period 2005 to 2010 in Table 3. Hydro One believes that the upward trend in payroll costs is reasonable in light of the steadily increasing transmission and distribution work programs since 2005, as well as the negotiated increases in labour rates.
Request:
Please summarize the year over year increase in payroll cost and provide the allocation between increasing work programs and increase in labour rates.

Response

The allocation of year over year compensation cost increases between increases in labour rates and increases in work programs / other is approximated as follows.

$ millions

Year	Total Compensation Increase	Increase attributed to increased work programs and attrition [1]	Increase attributed to increased labour rates
2006[2]	61.4	29	32
2007	36.2	26	10
2008	73.5	65	8
2009	20.2	9	11
2010	30.7	15	16

[1] New employees have been hired for succession planning and will also work on incremental work
[2] Increased compensation in 2006 partially due to 17 week Society strike in 2005

Ontario Energy Board (Board Staff) INTERROGATORY #43 List 1

Interrogatory

Issue 3.3
Are the compensation levels proposed for 2009 and 2010 appropriate?

Reference: ExhC1/Tab3/Sched2/p10
Preamble: Hydro One Networks payroll in historic year 2007 was $495.4 million and is $569.9 million in bridge year 2008.
Request:

a) What are the specific reasons for the 14.8% increase?
b) If there is more than one reason, provide the payroll increase associated with each reason.

Response

a) The 14.8% increase in total wages is a result of increased staff levels and escalation. Staff levels have increased due to increased work programs and hiring to address our demographic challenge. Escalation is a result of negotiated collective agreement increases and MCP salary increases.

b) Exhibit I, Tab 1, Schedule 42 provides the payroll increase associated with increased work program/ succession hiring and labour escalation.

Ontario Energy Board (Board Staff) INTERROGATORY #44 List 1

Interrogatory

Issue 3.3
Are the compensation levels proposed for 2009 and 2010 appropriate?

Reference: a) ExhC1/Tab3/Sched2/p10
b) ExhC1/Tab4/Sched1/p17

Preamble: There are several references to increasing work program in this exhibit. On page 10, Hydro One states, "For the period 2008-2010, the total Networks (Transmission and Distribution) work program is expected to increase by over 20%, whereas the regular staff increase is expected to increase by approximately 6%.

Questions:

With regard to Reference a)

a) Does this indicate that Hydro One will get more work done without increasing resources, or will there be an increase in contract staff?
b) How is the work program increase measured?
c) Provide the information supporting the 20% increase in work program.
d) How is the staff increase measured?
e) Provide the information supporting the 6% increase.
f) What is the contribution of the projected staff increase to the total payroll increase from $569.0 million in 2008 to $619.9 million in 2010?

With regard to Reference b)

g) Reference b) states that, "the budget for supply chain management increases by 8.7% from 2008 to 2010, reflecting the need to support overall forecast growth in the transmission and distribution work programs (42.9% in the same period).
h) Explain the difference in growth in transmission and distribution work program increase/growth, as described in the two references.

Response

a) This indicates a combination of both factors. That is, Hydro One will get more work done with proportionally fewer regular staff and there will also be an increase in contract staff utilized.

Please refer to Exhibit A, Tab 16, Schedule 1, entitled "Cost Efficiencies/ Productivity", for a full discussion of initiatives being undertaken by Hydro One to continue improving cost efficiency in the test years and beyond.

There will also be an increase in the volume of contracted out work and in the number of full turnkey contracts let to external organizations during this period. For example, to support our larger 2009 Transmission Development capital work program, $300M of external contracts are planned to be contracted out.

Completing our work programs using a mix of internal resources and external resources provides Hydro One with an increased work execution capacity as well as with greater flexibility to adjust to future work increases or decreases. These work execution practices also ensure we maintain adequate levels of critical resources and skills in-house.

b) The work program size is the total estimated cost for all OM&A and Capital work for both the Transmission and Distribution businesses. The work program increase is the year-over-year increase in these total expenditures.

c) The Hydro One work program consists of both Transmission and Distribution work. By summing the Distribution work volumes in the EB-2007-0681, 2008 Cost of Service Application ($1,055 million per year) and the Transmission work volumes in 2008 (of $1,096 million) and 2010 (of $1,524 million), results in a total work program of $2,151 million in 2008 and $2,599 million in 2010. This is a 20% increase in the total work program driven by Transmission work.

d) The measure is the percentage change in the total number of regular staff employed by Hydro One. This does not include part-time, temporary staff, casual workers, hiring hall workers, consultants or contract staff.

e) See Exhibit I, Tab 1, Schedule 19 for the projected increase in regular staff for the period 2008 to 2010.

f) The projected regular staff increase between 2008 and 2010 impacts total payroll by about $30 million.

g) N/A. No question was posed.

h) There was a calculation error made in reference “b)”. The corrected statement reads “the budget for supply chain management increases by 8.7% from 2008 to 2010, reflecting the need to support overall forecast growth in the transmission and distribution ***Sustainment, Development and Operations*** work programs (approximately ***29%*** in the same period). ***This 29% increase in the total Sustainment, Development and Operations work programs is driven by Transmission work.***”

The two exhibits demonstrate that the regular staff and supply chain cost increases are smaller relative to the increased work being done in the Transmission and Distribution programs.

In the exhibit referenced in a), growth is measured as an increase in Total Transmission and Distribution business Capital Expenditures and OM&A between 2008 and 2010. This 20% increase in the Total Transmission and Distribution business work programs is driven by Transmission work.

In the exhibit referenced in b), growth reflects the increase in Transmission and Distribution business Capital Expenditures and OM&A for Sustainment, Development and Operations only i.e. Shared Services and Other expenditures are excluded. This 29% increase in the total Sustainment, Development and Operations work programs is driven by Transmission work.

Ontario Energy Board (Board Staff) INTERROGATORY #45 List 1

Interrogatory

Issue 3.3
Are the compensation levels proposed for 2009 and 2010 appropriate?

Reference: a) ExhC1/Tab3/Sched2/p13
Preamble: Terms of Reference were prepared for the Mercer Canada Limited compensation benchmarking and the Oliver Wyman productivity benchmarking.
Question
: Please provide a copy of the terms of reference.

Response

Please see the following pages.

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Hydro One Network Inc.

Request for Proposal

Part 1: Instructions to Proponents

Part 2: Commercial Terms and Conditions

Part 3: Terms of Reference

Part 4: Format for Submission

Part 5: Attachments

Hydro One Networks – RFP 21399
Compensation Cost Benchmarking Study
Terms of Reference

1.0 BACKGROUND

1.1 Hydro One Networks Inc.

Hydro One Networks is an integrated Transmission and Distribution Utility which owns, operates and maintains high voltage and low voltage electricity delivery assets in the Province of Ontario and is responsible for delivering services to it's customers, including supply reliability, power quality, responses to customer inquires and billing services. Hydro One Networks is wholly owned by the Province of Ontario and is the leading electricity transmitter and distributor in Ontario. The Transmission and Distribution Businesses are operated in an integrated manner, utilizing the same workforce and many of the same business processes, systems and facilities. The Hydro One Networks mission is to be an efficient and dynamic transmission and distribution utility maintaining a constant attention to the development and retention of our employees, and creating shareholder value.
Nearly all of Ontario's electricity transmission system is owned and operated by Hydro One Networks. In 2006, the Transmission Business earned total transmission revenues of $1,245 million primarily by transmitting approximately 151 TWhs of electricity, directly or indirectly, to more than four million customers. The Hydro One Networks transmission system is one of the largest in North America, and is linked to five adjoining jurisdictions through 26 interconnections. Through these interconnections, the Transmission Business can accommodate imports of about 4,000 MWs and exports of approximately 5,800 MWs of electricity.

1.2 Electricity Regulation Framework

The Transmission and Distribution Businesses are separately regulated by the Ontario Energy Board (OEB); and cost allocation approaches are used within the company to appropriately assign costs to the Businesses. The OEB sets rates in proceedings through oral or written public hearings based on the level of revenue required to operate our regulated Businesses and to earn our approved rate of return on investment capital. Existing rates were set based on cost of service rate regulation.

2.0 Hydro One Compensation Costs Study

2.1 Compensation Costs Study Framework

In its August 16, 2007 decision approving Transmission Revenue Requirements for 2007 and 2008, the Ontario Energy Board provided direction and other expectations for further information on compensation and efficiency comparisons.

The Board asked for a study that would provide "useful and reliable information concerning Hydro One's compensation costs, and how they compared to those of other regulated transmission and/or distribution utilities in North America."

Toward that end, the Board directed "Hydro One to consult with stakeholders about the type of information to be gathered and the types of utilities and other companies that should be used for comparison purposes."

The Board went on to describe its expectation that “Hydro One would gather and compare data reflecting total compensation costs" and would also provide an “analysis of size and trends of labour costs per unit of output of various sustainment, development and corporate activities”.

The Board expects Hydro One to “provide empirical evidence which reveals the relative productivity of its workforce in comparison to other utilities”.

Hydro One has interpreted comments from the Board to be asking a larger question, and that is whether or not every aspect of Hydro One's compensation program is reasonable, when compared to other regulated utilities.

Anecdotal evidence and stakeholder opinions continue to mount promoting a perception of an unreasonably high compensation package, particularly when that compensation program is evaluated including all employee benefits paid to and on behalf of employees.

2.2 Deliverables

Hydro One is undertaking this Compensation Cost Benchmarking project with the expectations that the project will:

- Select, with justifications, an appropriate group of businesses to use as comparators to Hydro One for compensation cost benchmarking;
- Determine the most appropriate compensation metrics that each of the chosen comparators can readily measure.
- Quantify Hydro One’s Total Compensation Costs in comparison to other Ontario utilities, other like North American utilities, and other non-utility businesses competing in the same labour market;

- Evaluate the compensation costs of the benchmark group relative to the cost drivers, to assess how reasonable Hydro One's compensation costs are compared to the benchmark group;
- Identify and select utility labour cost drivers, including, but not limited to operational productivity, reliability, dependability, safety, competition for new employees, franchise characteristics, etc., to be incorporate into the benchmarking survey;
- Identify policies and/or practices used by utilities with respect to the determination of the particular services that are provided by the utilities' own direct employees and those services provide by contractors engaged directly or indirectly by the utilities, together with the costs of such contractor provided services.
- Determine productivity metric(s) that relate work output to compensation and measure these against the other comparators; and
- Be readily repeatable to permit periodic examination of Hydro One compensation cost trends.

> ***For the purposes of this benchmarking analysis "Total Compensation Costs" shall include the costs of all employee benefits, monetary compensation and other performance rewards that are paid to, or on behalf of the employee.***

3.0 SCOPE OF WORK

*3.1 Project Requirements**

Part A

1. Design a benchmarking study to deliver the Hydro One expectations outlined in section 2.2, giving due regard to intent of the Ontario Energy Board decisions referenced in section 2.1.

2. Present the proposed study design and proposed criteria for cohort selection to a stakeholder consultative for their understanding and input.

3. Meet with Hydro One to review suggested changes resulting from the consultative process, and then commence the study based upon the Hydro One approved study plan.

4. Provide an interim progress report to a Hydro One steering committee, with a potential requirement for a similar update to the stakeholder consultative, if requested by Hydro One.

5. Prepare a draft of the study report for presentation to the Hydro One steering committee.

6. Present the draft report to the stakeholder consultative, subject to any requirements for confidentiality, to gain the feedback and comment from intervenors.

7. Present a Final Report to Hydro One for filing to the Ontario Energy Board.

8. The successful consultant will be expected to defend the study plan, findings and conclusions within a regulatory proceeding. This would include all normal phases of a full hearing

including a written interrogatory phase, and other discovery processes defined by the regulator, and a full, formal regulatory hearing, either oral or in writing, before the OEB. This would also include the preparation of other related evidence, as necessary to support the methodology and measures applied related assumptions on economic parameters, comparable companies, etc.

9. Include in the study:

- The selection criteria for establishing a set of businesses used as comparators to Hydro One, and the justification for their choice as suitable cohorts in the benchmarking study. Where specific jobs are considered to be comparable to enterprises outside of the energy utility sector, the benchmarking study should be expanded to include the wider group for that specific job comparison.

- The criteria for selecting the compensation cost drivers, supported by the underlying justifications.

- Findings and conclusions regarding the reasonableness of Hydro One’s Total Compensation costs relative to other transmission and/or distribution utilities, taking into consideration the effects of the selected cost drivers.

10. Design the benchmarking study to be readily repeatable to permit a comparison trend analysis for future reviews.

11. Prepare for and participate in a stakeholder consultative process relating to the benchmarking study. This consultative process could involve as many as three (3) meetings, commencing with input to the study design and the cohorts selection, study status reporting, if required, and comments of the study draft. Hydro One wishes to fully inform the consultative about the study, to the extent that “confidentiality” issues permit, with the objective of gaining their endorsement of the process and the results. Hydro One will retain the right to unilaterally decide any question related to the study.

12. Prepare a draft report for review by Hydro One on or before April 30th, 2008 and a final report on or before May 30, 2008.

<u>Part B</u>

13. Participate fully, in cooperation with Hydro One, in the filing, discovery, hearing and argument phases of the Ontario Energy Board review of the compensation cost benchmarking study. Provide written responses to interrogatories on the study.

14. Defend the benchmarking study report and associated issues as an expert witness for Hydro One as and when required (likely up to two days on the witness stand), before the Ontario Energy Board at future Regulatory Hearings. This includes preparing expert witness testimony.

*** Note: Preparation of the study and report outlined in Part A above should be costed and a single lump sum price is to be provided. For Part B above, individual**

per diem rates, as appropriate, with an estimated total hour allocation for this work should be provided; expected reimbursable expenses must also be detailed.

3.2 Consultant Requirements

The consultant required for this assignment must:

- Be able to provide all of the services outlined in Section 3.0
- Have expertise and proven experience in preparing and providing a utility benchmarking study and recommendations in a regulatory environment
- Have in-depth knowledge and experience in applying general regulatory principles as they apply to the project scope
- Have knowledge of specific practices and precedents within the regulated utility industry;
- Have significant experience in acting as an expert witness at rate hearings in the subject areas covered by this work scope
- Be able to demonstrate that they have successfully completed similar work for other large clients, on time and on budget
- Comply with Hydro One's Code of Business Conduct
- Comply to Hydro One Commercial Terms & Conditions; Insurance and WSIB

3.3 Schedule

The schedule for carrying out the activities in Section 4.0 is driven by Regulatory requirements for a new rate order application to be submitted in early July 2008. The consultant shall base their response to this RFP on meeting the following schedule of major milestones:

1. Participate in up to three, one-day stakeholder sessions: January – June 2008

2. Deliver the Draft Report: ASAP, no later than April 30, 2008

3. Deliver the Final Report: ASAP, no later than, May 30, 2008

4. Fully participate in the defense of the Benchmarking Report in an OEB hearing forecast to occur in 2008 - 2009.

Ontario Energy Board (Board Staff) INTERROGATORY #46 List 1

Interrogatory

Issue 3.3
Are the compensation levels proposed for 2009 and 2010 appropriate?

Reference: ExhC1/Tab4/Sched1/p2
Preamble: Table 1 summarizes the Standard Labour Rate Composition for "Stations Regional Maintainer – Electrical".
Question:

Please explain why the costs associated with field trades supervision and other management and technical staff providing support services increased 44% from 2007 to 2008.

Response

Exhibit C1, Tab 4, Schedule 1, page 2, Table 1, provides a breakdown of labour rate composition for a Stations Regional Maintainer- Electrical into the underlying cost elements over the historic, bridge and test years.

Field Supervision and Technical Support cost is shown to increase by 44% from 2007 to 2008.

Prior to 2008, Field Supervision and Technical Support was both directly charged to OM&A and charged as a cost element in the labour rate composition. For 2008 and beyond, Field Supervision and Technical Support is 100% allocated to the labour rate composition to better align to the nature of the work they perform. The cost of Field Supervision and Technical Support activities has not increased by 44%, this is a refinement in cost recognition.

Hydro One seeks to reduce labour rates when opportunities are available. Please see Exhibit A, Tab 16, Schedule 2, for a listing of labour related cost efficiencies. Hydro One remains committed to lowering its overall compensation costs, while increasing its flexibility to run an efficient operation.

Ontario Energy Board (Board Staff) INTERROGATORY #47 List 1

Interrogatory

Issue 3.3
Are the compensation levels proposed for 2009 and 2010 appropriate?

Reference: ExhC1/Tab4/Sched1/p22
Preamble: There is work in progress to improve productivity in supply chain management, including obtaining quotes for materials required over multiple delivery dates, blanket purchasing orders and streamlining standards.
Question:
Please identify the financial benefit of these productivity improvements?

Response

Supply Chain has realized $26 Million in cumulative savings over 2005 to 2007 due to its strategic sourcing initiatives in the purchase of major equipment, commodities and services. These savings are of an ongoing nature which are realized as lower material and services costs within our work programs, thus mitigating OM&A and Capital increases over 2005 to 2007 as well as in the test years.

In general, efficiency and productivity improvements may be quantifiable in financial terms. However, these efficiency and productivity improvements do not result in improved financial returns to Hydro One. Rather, they enable Hydro One to deliver future work programs at a lower cost which in turn mitigates cost pressures on revenue requirement

Ontario Energy Board (Board Staff) INTERROGATORY #48 List 1

Interrogatory

Issue 3.3
Are the compensation levels proposed for 2009 and 2010 appropriate?

Reference: ExhA/Tab16/Sched1/p3
Preamble: One of the past and current cost efficiency initiatives is full use of temporary headquarters for work crews. The efficiency initiative reduces travel time and increases "wrench" time on the job.
Question:
Please provide the financial benefit of this productivity improvement.

Response

In the case of full use of temporary headquarters for work crews, Hydro One has been able to off-set increases in revenue requirement by approximately $1.8M annually over the historic and bridge years and this benefit is expected to continue annually.

As noted in Exhibit I, Tab 1, Schedule 47, in general, efficiency and productivity improvements may be quantifiable in financial terms. However, these efficiency and productivity improvements do not result in improved financial returns to Hydro One. Rather, they enable Hydro One to deliver future work programs at a lower cost which in turn mitigates cost pressures on revenue requirement.

Ontario Energy Board (Board Staff) INTERROGATORY #49 List 1

Interrogatory

Issue 3.3
Are the compensation levels proposed for 2009 and 2010 appropriate?

Reference: ExhA/Tab16/Sched2/Attachment1/p19
Preamble: Mercer Canada benchmarked the compensation for 17 Power Workers' Union roles. The weighted average multiple of the market median for these 17 roles is 1.21.
Question:

Please provide the drivers behind the multiple of the market median for regional maintainer – lines (1.43), service dispatcher (1.42) and stock keeper (1.42).

Response

It is the Regional Maintainer – Lines ***SUPERVISOR*** position which is at the 1.43 market median multiple, not the "Regional Maintainer - Lines" position.

There a number of drivers behind the multiple of the market median for the Regional Maintainer – Lines Supervisor. Specifically, this classification is a multi skilled trade position unlike the majority of respondents to the benchmarking survey. As a result, this classification is also able to work on both Transmission and Distribution assets. Legacy collective bargaining from Ontario Hydro also has an impact on this rate.

Legacy collective bargaining is the main driver behind the multiple of the market median for the Service Dispatcher and Stock Keeper positions. In the case of the Service Dispatcher at 1.42 of the market median, total cash compensation represents 65% of the above market positioning, benefit program 15% and pension 20%. For the Stock Keeper position, also at 42% above market median, total cash compensation represents 66% of the above market positioning, benefit program 14% and pension 20%.

Ontario Energy Board (Board Staff) INTERROGATORY #50 List 1

Interrogatory

Issue 3.3
Are the compensation levels proposed for 2009 and 2010 appropriate?

Reference: ExhA/Tab16/Sched2/p31
Preamble: The Mercer/Oliver Wyman productivity benchmarking study analysed 4 indicators - total compensation per: gross fixed assets, MWh sold, km of line, service territory. The transmission and distribution results are summarized on page 31.
Question:

There are outliers for cost/MWh and for costs/service territory. As such, are these robust indicators for productivity benchmarking?

Response

The indicators "cost/MWh" and "cost/service territory" are generally robust indicators of productivity. They looked at the amount that a company pays divided by a normalizing factor such as a measure of a level of output (MWh) or area serviced (service territory square km).

The presence of an outlier in the comparison set was shown by Mercer/Oliver Wyman to increase the clarity for those viewing the results of the study. The term outlier does not reflect on the quality of the indicator.

Mercer/Oliver Wyman provides results and conclusions based on data that includes the outliers. However, the outliers are clearly identified for completeness and transparency. If the outliers were removed, Hydro One's ranking would not be materially changed, e.g. in the case of costs/MWh, Hydro One ranking would be 1 of 6 (instead of 1 of 7), and for costs/territory size, Hydro One would be 4 of 5 (instead of 4 of 6). In both instances the single outlier would not affect the validity of the measure nor the conclusion drawn. Nevertheless, examining the four indicators in combination provides a more complete picture of productivity.

Ontario Energy Board (Board Staff) INTERROGATORY #51 List 1

Interrogatory

Issue 3.3
Are the compensation levels proposed for 2009 and 2010 appropriate?

Reference: ExhA/Tab16/Sched2/p36
Preamble: The customer service productivity benchmarking results are summarized on page 36. Hydro One's productivity indicators for customer service are better than the median for all indicators and ranks as the best relative to al its peers.
Question:
Please explain the drivers behind this result.

Response

The indicators for Customer Service is showing that Hydro One pays less, in total compensation for its Customer Service operations than its peer group, when adjusted for MWh, Line KM, Service territory, and Assets.

The determination of drivers behind the result was not part of the study.

Such a determination would be a major undertaking involving detailed analysis in cooperation with the other participants. In general, a study would need to assess and compare Hydro One's Customer Service practices and operational drivers with its peer operations in other utilities.

Ontario Energy Board (Board Staff) INTERROGATORY #52 List 1

Interrogatory

Issue 3.4
Is Hydro One Networks' proposed transmission overhead capitalization rate appropriate?

Reference: ExhC1/Tab5/Sched2/Attachment1/p3
Preamble: The 2009-2010 overhead capitalization rate has been calculated consistent with Rudden (now Black & Veatch) methodology. The pre-filed evidence states that "..while the departments that perform the CCFS activities can determine with reasonable accuracy the portions of time they spend on Transmission, Distribution, and the other business units, they are unable to determine with reasonable accuracy the time they spend on OM&A vs capital projects."
Clarification:

Please indicate whether Hydro One is planning to introduce a time records process to increase the accuracy of cost allocation between transmission and distribution, and within each between OM&A and capital projects.

Response

Hydro One will continue to follow the Rudden allocation methodology and is not planning to introduce a time records process to use in the cost allocation between transmission and distribution, and within each between OM&A and capital projects.

Hydro One continues to apply the Rudden methodology, that was accepted by the Board in EB-2006-0501, which uses the appropriate driver to allocate costs. Hydro One's position, as was the case in EB-2006-0501, is that the use of a time recording process does not necessarily lead to more accuracy of the allocations of common costs. For example, as noted in EB-2006-0501, many "CCF&S units do not allocate a portion of their time per activity directly to Transmission and/or Distribution activities since their activities serve all of Hydro One units and it is not possible to determine specifically which unit is being served" (EB-2006-0501, ExhJ/Tab1/Sch48).

Ontario Energy Board (Board Staff) INTERROGATORY #53 List 1

Interrogatory

Issue 4.1
Are the proposed 2009 and 2010 Sustaining and Development and Operations capital expenditures appropriate, including consideration of factors such as system reliability and asset condition?

Reference: a) ExhD1/Tab3/Sched2/p14/lines 13-16
b) ExhD2/Tab2/Sched3/Ref.# S1 and #S2

Clarification:
(i) Please clarify how many of the Oil Circuit breakers will be replaced by the end of 2010, noting that in Reference b), the narrative for Ref.#S1 states that more than 50% of the total number of breakers of 4,000 are oil circuit breakers.
(ii) When does Hydro One expect to complete replacement of all the oil circuit breakers on its system?
(iii) What is the average cost of replacing a typical 115 kV and 230kV oil circuit breaker?

Response

(i) Over the 2009 and 2010 period, Hydro One is planning to replace 26 oil circuit breakers (13 per year) that are deemed to be at end of life as part of the Sustainment program.

(ii) Hydro One does not have a detailed timetable for the replacement of all remaining oil circuit breakers. The removal of these technically obsolete assets remains a long term objective for Hydro One. The rate of oil circuit breaker replacements is reviewed annually, as part of the investment planning process, to establish short term investment plans. Hydro One prioritizes the work to replace oil circuit breakers considering other required work and the available funding. A description of the process to create the investment plan for circuit breakers can be found in Exhibit D1, Tab 3, Schedule 2, Pages 9 to 13, Section 3.1.2 Investment Plan Process.

(iii) At present it costs approximately $530,000 to replace a typical 115 kV oil circuit breaker, and $600,000 to replace a typical 230 kV oil circuit breaker. Oil circuit breakers are replaced with SF6 circuit breakers

Ontario Energy Board (Board Staff) INTERROGATORY #54 List 1

Interrogatory

Issue 4.1
Are the proposed 2009 and 2010 Sustaining and Development and Operations capital expenditures appropriate, including consideration of factors such as system reliability and asset condition?

Reference: ExhD2/Tab2/Sched3/Ref.# S8/paragraph 1
Preamble:
In the Reference, under Need: the project (total capital cost of $120.9 million) includes provision of one new diameter and nine new breakers to accommodate New local generation and future network expansions.
Question:
(i) Please provide the cost of installing the additional diameter and the nine new breakers mentioned in that Reference.;
(ii) Please indicate the rationale for not classifying the cost of the new diameter and nine new breakers as "Development" capital.

Response

(i) The total cost for the additional diameter and nine new breakers is estimated at $72 Million. The cost for these elements is difficult to identify precisely because the project was outsourced as a bundled turnkey project.

(ii) This Network investment is primarily Sustainment work. Six of the nine new breakers are direct replacements for existing end of life 230 kV GIS circuit breakers at Claireville TS. The total work at Claireville TS, including the addition of one new diameter and the other three new breakers, was initiated to facilitate the Sustainment work. The completion of this Sustainment work will improve the transmission system operability and reliability as well as allow new local generation and future network expansions.

Ontario Energy Board (Board Staff) INTERROGATORY #55 List 1

Interrogatory

Issue 4.1
Are the proposed 2009 and 2010 Sustaining and Development and Operations capital expenditures appropriate, including consideration of factors such as system reliability and asset condition?

Reference: a) ExhD1/Tab3/Sched2/p.21/Figure 6
b) ExhD1/Tab3/Sched2/p.24/Table 5

Clarification:

(i) In Reference a), is the number of transformers at EOL shown for the four years cumulative. If so, please confirm that there are:
- about 20 transformers would reach EOL during 2008 (225-205);
- about 15 transformers would reach EOL during 2009; and
- about 10 transformers would reach EOL during 2010.

(ii) In Reference b), the Table show the transformers listed for the various stations corresponding to the seven Projects S10 to S 16, which total 18 transformers that reached EOL during 2009 and 2010.

(iii) Please provide some clarification in regard to the two sources of information outlined in (i) and (ii) above, where in (i) there are a total of about 25 transformers reaching EOL and in (ii) there are only 18 transformers that reached EOL.

Response

(i) The bar chart is cumulative. Specifically:
- 21 transformers will enter the EOL region during 2008
- 16 transformers will enter the EOL region during 2009
- 7 transformers will enter the EOL region during 2010

(ii) The seven Projects S10 to S16 show the 18 EOL transformers that Hydro One is planning to replace in 2009 and 2010.

(iii)The transformers in the EOL region provides an indication of the likely trend in volume of EOL replacements in future years. As noted in part i above, 23 transformers are entering end of life region in 2009 and 2010 which adds to the pool of transformers already in the EOL region. The 18 transformers that are deemed to be at their end of life were selected through the investment plan prioritization process based on information that is specific to those assets, as opposed to fleet demographics (i.e. transformers entering the EOL region). Hydro One prioritizes the work to replace the transformers considering other required work and the available funding and resource levels. A description of the process to create the investment plan for transformers can be found in Exhibit D1, Tab 3, Schedule 2, Pages 19 to 22, Section 3.3.2 Investment Plan Process.

The total risk of having transformers in the EOL region is mitigated by the prudent replacement of assets, maintaining an adequate level of system spares, and continued maintenance and diagnostic programs.

Ontario Energy Board (Board Staff) INTERROGATORY #56 List 1

Interrogatory

Issue 4.1
Are the proposed 2009 and 2010 Sustaining and Development and Operations capital expenditures appropriate, including consideration of factors such as system reliability and asset condition?

Reference: ExhD2/Tab2/Sched3/Ref.# S15/Summary - paragraph 2
Preamble:
The Reference indicates that replacement for Transformers T7 and T8, may be either:

- like-for-like where the size the new transformers will be the same as the replaced ones (each with capacity of 83 MVA); or
- Increase transformer capacity (each with capacity of 125 MVA)

Questions:
(i) If Hydro One opts to replace the transformers with larger size, would that be to accommodate increased load (load growth) from load customers served by these two transformers?
(ii) If response to (i) indicates that load growth is the trigger for the added capacity, please provide the name of the load customers, including distributors, and the amount of added load from each customer.
(iii) Would Hydro One follow the procedures outlined in the Transmission System Code to conduct economic evaluation to determine whether or not capital contributions need to be recovered from these load customers?

Response

i) Yes. In all cases Hydro One evaluates, in consultation with the customer, if increasing capacity is necessary. If customer load growth justifies the need, additional capacity could be added to the station, provided that the customer makes the required capital contributions to fund the additional capacity.

ii) In further consultation with the customer the option of using an 83 MVA transformer has been selected.

iii) Yes.

Ontario Energy Board (Board Staff) INTERROGATORY #57 List 1

Interrogatory

Issue 4.1
Are the proposed 2009 and 2010 Sustaining and Development and Operations capital expenditures appropriate, including consideration of factors such as system reliability and asset condition?

Reference: ExhD2/Tab2/Sched3/Ref.# S35/Summary - paragraph 2
Preamble:
The Reference indicates that replacement for the 115 kV circuit P3S from Port Hope Jct to Sidney TS (60.1 km) is recommended due to the deterioration of the circuit.
In the Summary Section of the Reference, Hydro One stated in part that:

> *"This investment will consist of replacing the existing 477 kcmil ACSR conductor with new 732 kcmil conductor on the 60.1 km section of line between Port Hope Jct and Sidney TS. The 732 kcmil compact conductor is a readily available modern standard conductor that is adequate for replacement of the existing conductor while delivering additional current carrying capacity and reducing line losses by about 35%.*"

The Summary Section of the Reference goes on to state in part that:

> *"Proposed refurbishment work will return this section of line to a near-new condition and will also meet future load growth demands."*

Questions:
(i) Please identify the load customers whose load growth will be accommodated by the increasing the size of the conductors from 477 kcmil ACSR to 732 kcmil.
(ii) Would Hydro One follow the procedures outlined in the Transmission System Code to conduct economic evaluation to determine whether or not capital contribution need to be recovered from the load customers?

Response

i) Circuit P3S connects Dobbin TS, Dobbin DS, Port Hope TS and Sydney TS. These stations supply Hydro One Distribution and embedded LDCs, Peterborough Distribution, Veridian Connections and Lakefront Utilities.

ii) This project is not driven by a request from load customer(s) but initiated independently by the transmitter to refurbish an existing facility. As such, Hydro One does not believe an economic evaluation is required in this case.

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

Interrogatory

Issue 4.1
Are the proposed 2009 and 2010 Sustaining and Development and Operations capital expenditures appropriate, including consideration of factors such as system reliability and asset condition?

Reference: ExhD1/Tab1/Sched2/p1/Table 1
Request:
In Table 1, under "Development" category for 2007, a Variance of $ 73.6 Million is indicated. Please provide the name of the projects contributing to this variance of $73.6 Million, and for each project the amount attributed in $ Millions.

Response

Please see the table below. In-Service additions over $1 million in value are shown separately, and those less than $1 million are grouped in "other".

	2007 I/S Additions		
($ millions)	**Actuals**	**OEB Approved**	**Variance**
Major Projects (with variance over $1.0M)			
Toronto Niagara Link	36.7	43.1	(6.4)
Debeers Mine in Northeast	3.3	0.4	2.9
2007 - Replacement of Transformer Rod Gaps with Surge Arresters at Selected Stations	-	1.6	(1.6)
Cambridge Preston – Build Line	23.2	20.6	2.6
Oshawa GM – Prepare Release	16.5	18.5	(2.0)
Queenston Flow West Breakers - Install Synchrocheck Reclosing	-	1.2	(1.2)
London Talbot TS –Add DESN Station	14.1	12.1	2.0
SPS Lambton & Scott – New Gen	1.2	-	1.2
Lambton TS – Split 230kV Buses (1)	40.3	-	40.3
Toyota Woodstock – Supply Plant	2.9	4.3	(1.3)
Essa TS: Reterminate 230 kV Circuits E27 and M6E	-	1.9	(1.9)
Add New 44 kV cap banks at Meadowvale TS	-	1.0	(1.0)
Belle River TS -Add 21.6MVAr Capacitor	-	1.4	(1.4)
HON HQ Est 1250MVA Perm Interc (2)	43.1	-	43.1
HV Shunt Caps Fast TRV Issue	4.0	-	4.0
Toyota Woodstock Bld 115kV	1.3	-	1.3
Sub-Total	**186.7**	**106.1**	**80.6**
Other (less than $1M)	66.4	73.4	(7.0)
Total	**253.1**	**179.5**	**73.6**

(1) Lambton TS was approved in EB-2006-0501 (IJD D19, Exhibit D2, Tab 2, Schedule 3) for $53.8 million. A portion of this project (reconfiguration of North-South yard to allow Greenfield connection) was placed in-service date in 2007.

(2) The Hydro-Quebec project was approved in EB-2006-0501, (IJD D1, Exhibit D2, Tab 2, Schedule 3) for $115.3 million. A portion of this project was placed in-service in 2007.

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

Interrogatory

Issue 4.1
Are the proposed 2009 and 2010 Sustaining and Development and Operations capital expenditures appropriate, including consideration of factors such as system reliability and asset condition?

Reference:
a) Pre-filed Evidence for Proceeding RP-2000-0068, ExhB/Tab4/Sched2/p1
b) ExhD2/Tab2/Sched3/Invest.Summary/Ref. # D1

Preamble: In Reference a), the project cost estimate approved is shown to be $ 96.536 Million, and the cost for the same project is shown in Reference b) to be $122.8 million.
Request:
Please provide a short summary showing the variance in costs by category e.g. “Engineering & Studies”, “Station and Telecommunication”, “Transmission Line Facilities”, and for each category to be broken to “Labour”, “Material”, and “Overhead”.

Response

The reasons for the increase in the cost of the Hydro Quebec Interconnection Project (# D1) from $96.5M to $122M were previously detailed in Board interrogatory Exhibit J, Tab 1, Schedule 81 submitted as part of proceeding EB-2006-0501, which is attached to this response for convenience.

Details of the costs, in the categories requested, are provided in the table below:

	$96.5M Estimate				$122.8M Estimate			
	Labour	Materials	Overhead	**Total**	Labour	Materials	Overhead	**Total**
Engineering & Studies	9.6	0.0	0.5	**10.1**	7.4	0.0	0.9	**8.3**
Station & Telecommunication	10.3	20.2	1.7	**32.2**	12.3	18.1	3.8	**34.2**
Transmission Line Facilities	20.9	30.3	2.9	**54.2**	25.8	45.8	8.8	**80.3**
	40.8	50.5	5.2	**96.5**	45.5	63.9	13.5	**122.8**

EB-2006-0501 Exhibit J, Tab 1, Schedule 81

Ontario Energy Board (Board Staff) INTERROGATORY #81 List 1

Interrogatory

Issue Number: 3.2
Issue: Are the amounts proposed for Capital Expenditures in 2007 and 2008 appropriate? (D1/T3/S1&3)

Ref: (a) D2/Tab3/Sch3/Reference #:D1
(b) Hydro One Application (RP-2000-0068) B/Tab4/Sch1/page1

Ref. (a) shows a total expenditure for the project by 2009 to be $101 million, while in Ref. (b) showing the original proposal, the project cost was estimated to be $ 96.536 million. Please provide a detailed explanation for the variance between the two cost estimates covering increases due to labour salary increases, material increases (such as installation of poles instead of lattice towers in portion of the former City of Cumberland).

Response

Correction Notice: Board Staff reference "D2/Tab3/Sch3" should read "D2/Tab2/Sch3"

A revised estimate of $124M total costs, of which $122.1 was Capital and $1.9M was removal costs, was approved by the Hydro One Board. Excluding AFUDC to correspond with the submitted treatment for the HQ tie project, yields an updated net Capital cost of $114.1M. This updated estimate will be filed with the OEB as part of Hydro One Networks' update to the rate filing in February, 2007. The reconciliation of the original proposal to this revised estimate is as follows:

Original Estimate per RP-2000-0068	$96.5M
• Increased Stations Cost, primarily due to escalation	1.1M
• Increased lines material costs (cost of steel structures has increased by $8.2M given increase in number of structures to reflect use of poles as ordered by OEB and better information on egress from Hawthorne as well as higher steel prices; conductor cost has increased by $2.2M; foundations are more expensive by $2.2 M due to poorer than expected soil conditions)	12.5M
• Increased Construction costs due to escalation and increased work related to steel poles, foundations, and egress	2.7M
• Decreased line engineering costs	(0.5)M
• Increased line contingencies to reflect increased	7.7M

uncertainty related to soil conditions, footings and egress, and increased complexity of outages

- Increase in lines AFUDC 2.0M

Revised Capital including AFUDC $122.1M

- Removal of AFUDC per rate filing treatment (8.0)M

Estimate per Update to Rate Filing $114.1M

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

Interrogatory

Issue 4.1
Are the proposed 2009 and 2010 Sustaining and Development and Operations capital expenditures appropriate, including consideration of factors such as system reliability and asset condition?

Reference: ExhD1/Tab3/Sched3/Project D5/p15/lines 9-19
Preamble:
In the Reference above, Hydro One stated in part that:

> *"…Assuming a project life of 45 years, and assuming that these benefits remain constant, the Net Present Value ("NPV") of the benefits is estimated to be between $83 and $104 million based on a real (social) discount rate of 4% that is used in the OPA's Integrated Power System Plan. When discounting unescalated, non-utility cash flows such as congestion and reliability penalties, use of a real social discount rate is more appropriate rather than a utilityspecific, nominal, after-tax discount rate. Thus, the NPV of the benefits exceeds the$80.5 million cost of the discretionary work for unbundling the circuits."*

Questions:
(i) Please provide a definition of what is referred in the above Reference as "social discount rate";
(ii) Please provide details in regard to calculation of the social discount rate from basic principles, and how the social discount rate would vary in response to various varying economic conditions such as economic downturns, varying risk evaluation of a project, leading to either an increase or a decrease in the real discount rate etc.;
(iii) Please provide information on the experience in other jurisdictions in the U.S.A and in Canada in regard to assessment of electricity transmission projects where "social discount rates" were used. For each case please provide the details on how the social discount rate was calculated.

Response

i) The "Social Discount Rate" is discussed in the Ontario Power Authority's (OPA) Integrated Power System Plan (IPSP). Please refer to EB-2007-0707 Exhibit D, Tab 3, Schedule 1, Attachment 1 pages 4 to 5 for a discussion of the Social Discount Rate.

ii) An Ontario Ministry of Finance paper, "The Social Discount Rate for Ontario Government Projects" (January 2007) discusses how the Social Discount Rate is calculated, its sensitivities and appropriateness for use. Please refer to EB-2007-0707, Exhibit I, Tab 31, Schedule 85, Attachment 1 & 2 for this paper.

iii) Please refer to EB-2007-0707, Exhibit I, Tab 38, Schedule 32 for information on the experience of other jurisdictions in the use of "social discount rates" for projects, including electricity supply projects. Since a transmission project has a service life similar to that of an electricity supply project and both are installed for the betterment of the ratepayer, it can be argued that the use of a "Social Discount Rate" is equally appropriate for both. Information on how these rates were calculated is not available.

These documents are available on the OEB website (http://www.oeb.gov.on.ca/OEB/) under the Integrated Power System Plan (IPSP) Review. Copies of the documents are also attached to this interrogatory as follows:

Attachment 1: EB-2007-0707 Exhibit D, Tab 3, Schedule 1, Attachment 1
Attachment 2: EB-2007-0707 Exhibit I, Tab 31, Schedule 85, Attachment 1 and 2
Attachment 3: EB-2007-0707 Exhibit I, Tab 38, Schedule 32

EB-2007-0707 Exhibit D, Tab 3, Schedule 1, Attachment 1

ECONOMIC ANALYSIS OF GAS-FIRED AND NUCLEAR GENERATION RESOURCES

1.0 SUMMARY

This paper outlines the results, methodology and data used to determine the requirements for base load and peaking resources in the Integrated Power System Plan (the "IPSP" or the "Plan"). The results are similar to those presented in the Supply Mix Advice report released December 9, 2005.

2.0 INTRODUCTION

An efficient power system requires a balance of resource capabilities to meet the daily and seasonal requirements for capacity, energy, operating reserve, and other services, and do so in the most economic manner. This balance of resource capabilities will require a proper allocation of supply between baseload, intermediate and peak supply components. As discussed in the original Supply Mix Advice report, these resource components can be defined as follows:

A baseload plant generally has higher fixed costs and has a relatively low portion of its total costs as variable costs, such as hydroelectric and nuclear generators, for example. Its overall economics improve the more it is used as its high fixed cost is spread over a greater level of output. A resource with baseload capability is well suited for meeting the portion of load that exists much of the time, and for continuous operation at constant rates of production[1]. Some baseload resources, such as nuclear, require relatively long start-up and shut-down times and have limited ability to increase or reduce output in response to short-term variations in demand. Some types of hydroelectric, on the other hand, are typically much more capable of responding to short-term variations in demand.

[1] Exceptions to this generalization include wind power, run-of-the-river hydro, and some cogeneration. These resources are used whenever they are available, such as when the wind blows, when the river runs, or when steam is required (in the case of a cogeneration facility).

Peaking resources have the opposite characteristics of baseload plant, with fixed costs that are relatively low and variable costs that are high. Peaking resources are therefore attractive for meeting load that is present for a relatively small portion of the time. A peaking resource is capable of ramping up very quickly to meet brief spikes in demand throughout the day or night. Peaking generation is also capable of providing power and energy on short notice, for example taking up the “slack” resulting from an unexpected loss of another generation resource. Simple-cycle gas turbines (“SCGT”) and hydroelectric with storage capability are examples of peaking resources.

Intermediate resources, as the name suggests, have characteristics that lie between the baseload and peaking plants. An intermediate resource is capable of increasing its output in response to daily demand swings. The morning and early evening rush hours are examples of such swings, and can account for changes of 5,000 MW or more within several hours. Coal-fired generation and combined-cycle gas turbines (“CCGT”) are examples of intermediate resources that typically will have relatively higher marginal costs (fuelling) and greater flexibility than base load plants.

This report will analyze the economics of various generation resource technologies to estimate the proper allocation of supply between baseload, intermediate and peak supply components for the Ontario power system.

3.0 ECONOMIC EVALUATION METHODOLOGY

A method used throughout the development of the Plan, is to compare the costs of alternative generation resources on the basis of their Levelized Unit Energy Cost (“LUEC”). LUEC is the average cost of the energy produced from an electric power generator over its service life, considering all the costs in the lifecycle of the plant, including its construction, operation and fueling, and decommissioning costs. In the definition that the OPA has adopted, LUEC is the price (escalating at the rate of inflation) that would have to be charged for each MWh produced over the lifetime of a generator that would provide the revenue stream with the same present value as the direct costs of construction, operation and decommissioning of the plant.

For the calculation of LUEC of a project with construction cost, K (including financing costs as valued at the date of service start-up), annual energy production, Q, at real annual cost, C (including fuel, operations and maintenance valued in constant dollars of the year at service start-up) in each of the L years of service life, and real (net of inflation) discount rate of r, the LUEC is estimated as:[2]

$$LUEC = (K \times r / Q) \div \{ 1 - (1+r)^{-L} \} + (C/Q)$$

The LUEC is expressed in constant (real, net-of-inflation) dollars of the base year in which service begins, per Megawatt-hour of energy produced.

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[2] More generally, the LUEC may be estimated for a generator with annually varying capital modification cost, annually varying production cost and volume, and decommissioning cost

The calculation of LUEC involves accumulating the generator's discounted cashflow costs to a total present value (PV) of construction, operating and post-service costs, and then "averaging" that PV over the generator's total production.

The first step is to calculate the present value (PV) of the generator's lifecycle cost:

$$PV = \sum (\text{capital.cost}_m + \text{operating cost}_m + \text{capital modification cost}_m + \text{decommissioning cost}_m) \times \text{discount factor}_m$$

On the right-hand side of the above expression:
The costs may be expressed in terms of constant real dollars of a base year, or , alternatively,in terms of escalated dollars including inflation. With the discount factor correspondingly expressed in real or escalated terms, the present value result is identical.
The capital cost in the above formula is the cost of design, engineering, construction and commissioning, *excluding* the allowance for interest or other financing costs during construction. The operating cost includes the cost of fuel, routine maintenance, and administration for the generator. The sum $\sum$ of the annual products of capital cost and discount factor is used in a way that is analogous to the generator's *gross* asset value including the cost of financing during construction.

The second step is to calculate the LUEC as a "present value average" of the PV cost over the lifecycle energy production. This is done by dividing the PV into the "volume present value" of the generator's lifecycle energy production:

$$LUEC = PV \div \sum (\text{annual energy production volume}_n) \times \text{real discount factor}_n$$

In the above expression, the real discount factor (which excludes the effect of inflation) must be valued at 1 in the year of service start-up. The real discount factor$_n$ in year n is equal to the real discount factor$_{n-1}$ in year (n-1) divided by (1+real discount rate)
If the annual energy production volume has the same value Q each year, and if the real discount rate has the same value r each year, then

$$LUEC = (PV \times r/Q) \div [1- (1+r)^{-L}] \}$$

The LUEC of a generator is sensitive to the amount of energy it produces. The more energy, the lower the LUEC, as the capital costs are spread over a larger amount of energy.

In addition, the value of the LUEC is sensitive to the discount rate: a higher (or lower) discount rate raises (or lowers) the LUEC just as higher (or lower) financing affects overall costs.

3.1 Need for a Discount Rate

As described in the previous section, a discount rate contributes to the determination of a project's net present value ("NPV"). The reason for discounting is to represent the generally-accepted proposition that a dollar in a future year is worth less than a dollar in the current year. Put another way, "People prefer to consume a given amount of resources now rather than in the future."[3] Accordingly, the present value of a stream of future cash flows is the sum of successively discounted yearly cash flows.

Different discount rates are used to evaluate private and public investments in the economy:

- Businesses use their own measures of Return on Equity ("ROE") or Weighted Average Cost of Capital ("WACC") after-tax rates to discount investment costs and private returns accruing to them on an after-tax basis in unregulated markets;
- Regulatory agencies allow utilities to earn a specified rate of return on capital, depending on the utility's deemed conditions of capital structure and risk;
- Households postpone some consumption in favor of savings, depending on interest rates on bank savings accounts, RRSPs, or other personal savings vehicles;
- Governments undertake (or mandate) projects of infrastructural, environmental, or health and safety enhancement in the wider public interest, assessing project merit in terms of the long-term return to current and future generations of society as a whole, using a Social Discount Rate ("SDR");

The resulting LUEC is expressed as a per MWh cost in constant dollars of the year of service start-up.

[3] by Moore, Boardman, Greenberg (p.75)

- In the Ontario Ministry of Finance paper, “The Social Discount Rate for Ontario Government Projects” (January 2007), P. Spiro recommends using 5% as the real SDR. This value is calculated based on estimates of Canadian corporations’ Weighted Average Cost of Capital -- with an adjustment to represent corporate returns *before* deducting Ontario income tax, but *after* deducting Federal income tax.

3.2 Appropriateness of Social Discount Rate for the IPSP

SDR is normally applied to investments to serve the wider public interest, such as public infrastructure, or projects for environmental or health and safety enhancement. The benefits of such projects are widespread and cannot be restricted to any identified specified group of users. In the same way, such projects are not associated with “market returns” flowing to specified project owners. By contrast, business investments, which are evaluated through ROE and WACC rates, are designed to service specified customers, and yield the consequent market returns to the project’s shareholders and creditors.

SDR is normally applied to projects whose effects include benefits, costs, and foregone opportunities that endure into the long-term and affect future generations. By contrast, business investments are usually designed to yield shorter-term benefits.

Electricity system-related investments, include transmission and distribution, and include renewables and Conservation funded by utilities, end-users and government. They have characteristics of both public and business investments.

The projects are generally undertaken in the wider public interest, and thus have characteristics of public infrastructural, environmental or health-related investments. As such, some of the benefits of such projects extend beyond specific services sold to identified customers, but are dispersed uncontrollably as societal benefits. Correspondingly, the project’s financial value extends beyond the investor’s returns, but includes also government tax revenues which are also a potential resource for public benefit.

The projects have long gestation periods, with much of the benefits yielded in the long-term and to future generations. In this way, such projects may be considered to require a wider range of criteria than that used for business decision-making.

The OPA uses a SDR for economic evaluation of the power system plan portfolio because it is assessing the portfolio of electricity-related projects in the public interest, taking into account infrastructural and environmental aspects with long-term implications for current and future generations.

3.3 OPA's Use of Social Discount Rate in the IPSP

The following summarizes the OPA's use of the SDR in the IPSP:

- The SDR reference value is 4% in real terms;
- For sensitivity analysis, 2% and 8% are used as alternative values for the real SDR;
- The same SDR is used to discount each cash flow cost of each existing and new supply- and demand-side facility in the Plan;
- A Plan which has a lower NPV cost is favoured over a Plan with a higher NPV cost assuming both plans meet Directive and system reliability requirements;
- Externalities are not monetized in the NPV system cost; and
- Income tax on the generator's profits is not included in the NPV of Plan costs.

3.4 Determination of the Value of Social Discount Rate for the IPSP

In determining the value of an SDR to assist in choosing between current economic benefits and long term economic benefits, the OPA considered the situation of an Ontario resident deferring current consumption in order to invest in an RRSP to provide for future consumption.

OPA estimated that a long-term Government of Canada bond providing a nominal 5 ½%-6% interest including 2% inflation, held for 6-25 years in an RRSP by an Ontario resident until retirement, yields a real after-tax return of 3 ½% - 4 ½% compounded annually. This means that the individual chooses to defer consumption in favour of gaining a net annual 3

½% - 4 ½% into the long-term. This is a reasonable proxy for an individual's Rate of Time Preference extending into the long-term, and a reasonable representation for the discount rate.

Accordingly, OPA has chosen its reference value for the real SDR as 4%. The 4% value is highly approximate[4], depends on specific assumptions, and is meant to represent the "aggregate" of individuals' Rates of Time Preference.

Due to the wide range of authoritative estimates for the SDR, it is prudent to examine the degree to which the economic preference for the recommended projects would be affected by SDRs of lower or higher value than the reference 4% real rate. Accordingly, where appropriate, the OPA tests sensitivity using 2% as a lower SDR value, and 8% as a higher SDR value.

3.5 Consistency with Ontario Energy Board's Direction

The OPA uses a "real" net-of-inflation discount rate applied to costs expressed in "real" dollars-of-base-year. The OEB's guidance is to use a discount rate applied to costs expressed in "dollars-of-the-year". With the appropriate discount rates, these two methods are completely equivalent, and provide identical NPV estimates expressed in dollars of a single base year.

For example, the OPA's practice of applying a "real" discount rate of 4% to "real" costs expressed in dollars-of-base-year produces exactly the same NPV estimate as does applying a "nominal" discount rate of 6.08% to costs expressed in "escalated dollars-of-the-year" including inflation assumed at 2%.

The OPA applies its discount rate to all applicable costs and savings associated with every existing facility and new project in the IPSP, and so satisfies the OEB's requirement that the NPV include all applicable costs.

4.0 ECONOMIC DEFINITION OF A BASELOAD PLANT

In order to determine the appropriate amount of baseload resources to include in the Plan, the cost of representative baseload technologies is compared. For the purposes of this analysis, nuclear and CCGT generation are compared economically. The cost of nuclear generation selected as representative for this analysis is $2,900 per kW[5].

The cost of nuclear generation has been compared to the cost of an intermediate resource technology, in this case a CCGT plant, to determine the appropriate boundary between baseload and intermediate resources and hence the appropriate amount of baseload within the total Plan generation resource portfolio. It should be noted that the estimated percentage of baseload resources resulting from this analysis would, by necessity, include other resources that would be lower cost baseload supply options (e.g., hydro, Conservation, etc.). It is not intended to imply that all baseload resources would be comprised of nuclear generating units.

Assumptions for CANDU 6 nuclear units are based on the OPA's Supply Plan and the CCGT costs are listed in Table 1 and are those given in the Navigant Consulting Inc. ("NCI") Cost of Entry study[6]. Note that these assumptions do not consider the environmental impact of the different technologies or quantify the associated cost.

It should also be noted that CANDU 6 has the highest expected costs of the nuclear alternatives. The use of the CANDU 6 cost estimates is therefore conservative, i.e., it tends to lower the estimate of the requirement for base load resources.

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[4] OPA lowered the SDR reference value from the 5% real rate in the Supply Mix study to the 4% real rate in the IPSP. The SDR was lowered because real rates of return on long-term Government of Canada bonds, a component of SDR, have fallen since the Supply Mix estimates were prepared.

[5] This represents the higher end of the range of costs, corresponding to CANDU 6. Other estimates include AECL's ACR 700 and ACR 1000 at $2,400/kW and $2,500/kW respectively, as well as the Westinghouse unit at $1,900/kW

[6] Evaluation of Costs of New Entry, Study by Navigant Consulting Inc. February 2007

Table 1: Technology Assumptions

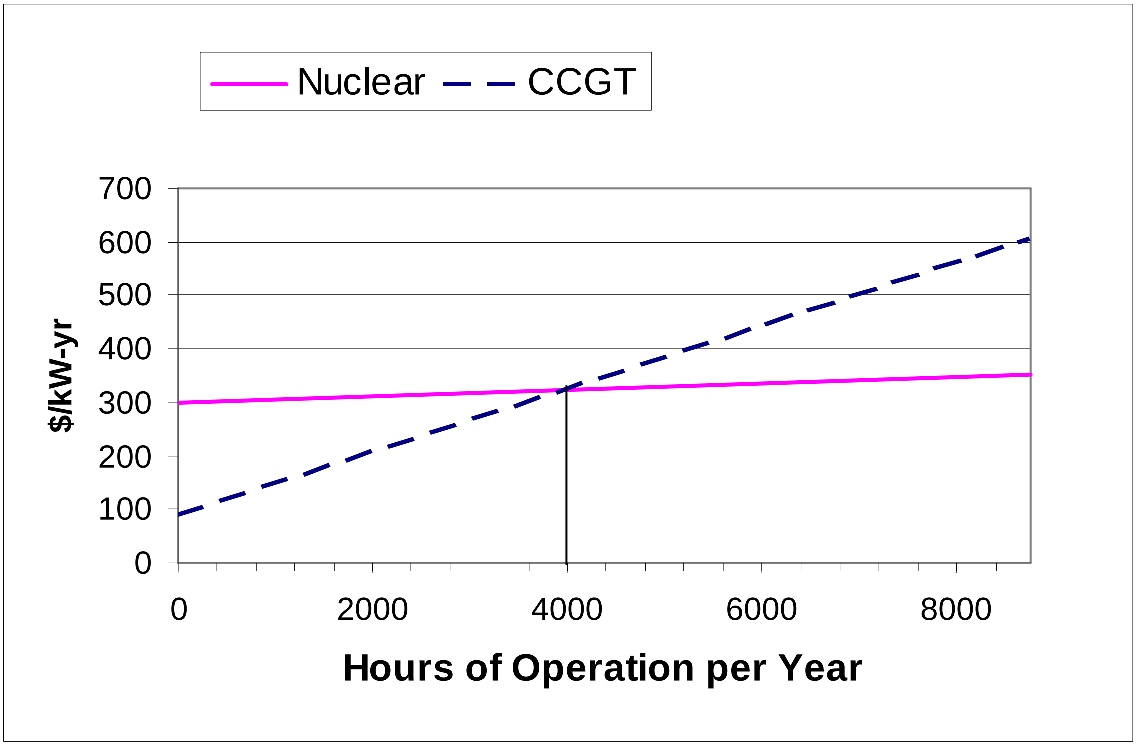
	Nuclear	CCGT
Station Size (MW)	1346	500
# of Units	2	2
Unit Capital Cost ($/kW) (ex idc)	2907	924
Construction time (years)	6	3
Accounting Life (years)	40	20
Decommissioning costs $M per station	837	
Retubing Cost $m/unit	295	
Life before retubing (years)	30	
Efficiency (BTU/kWh)		7000
Variable OM&A ($/MWh)	1.43	2.75
Fuel Cost ($/kgU and $/mmBTU)		
Fuel Cost ($/MWh)	2.7	56
Spent fuel Processing ($/MWh)	1.68	
Fixed OM&A ($/kW-yr)	108	17
Ongoing capex ($/kW-yr)	9	

Source: OPA

When comparing a baseload plant to other technologies that are relatively cheaper to build but more expensive to operate, it is instructive to look at how the total costs vary with the numbers of hours of operation per year. This type of analysis will help determine how often high fixed/low variable cost plant must operate to have lower overall costs than a low fixed/high variable cost plant.

Figure 1 compares the total annual costs expressed in $/kW-year for a nuclear plant and a CCGT plant for a range of annual hours of operation. This is based on a real discount rate of 4%.

Figure 1: Breakeven Hours of Operation on a $/kW Year Basis

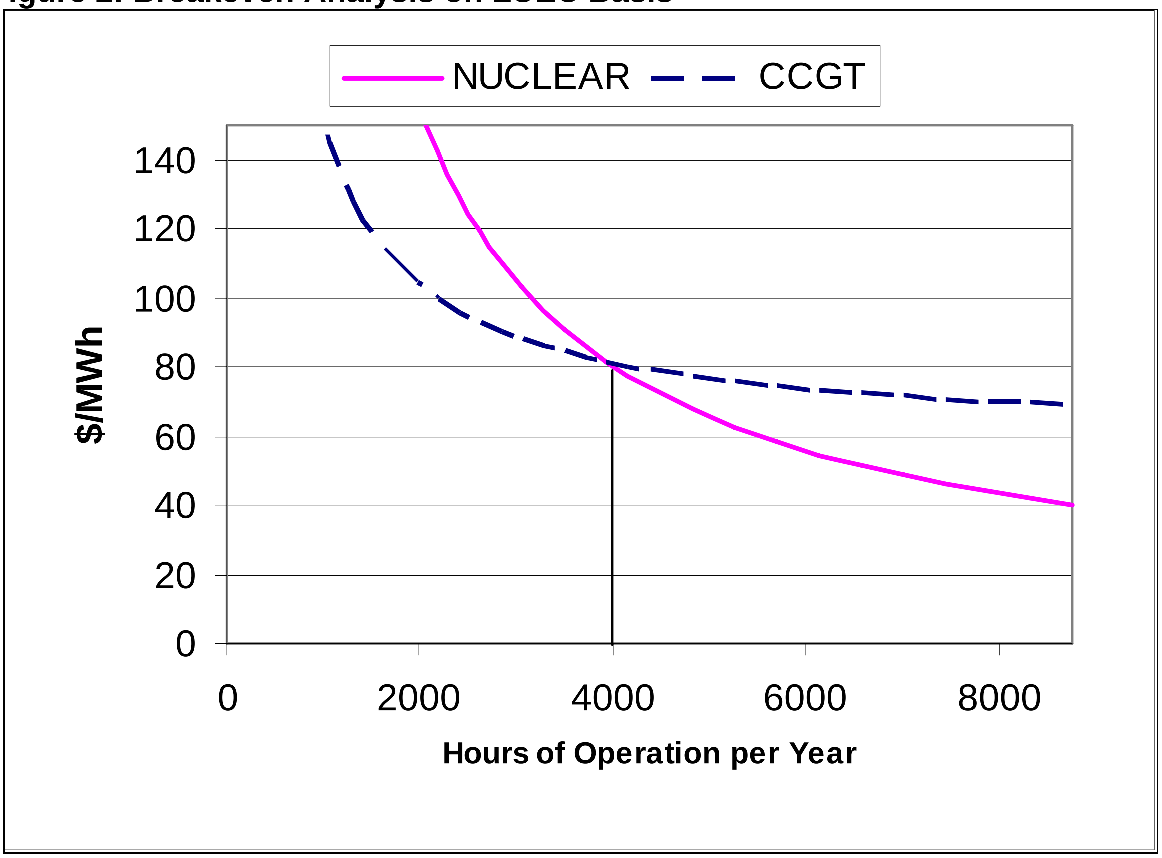


Source: OPA

Since the variable cost for a nuclear plant is relatively low, its total cost expressed in $/kW-year does not increase significantly as the number of hours of operation per year increases. However, the variable costs for a CCGT plant are relatively high, and therefore the total cost expressed in $/kW-year does increase significantly as the hours of operation increase. As illustrated above, the cross-over point for these two technologies occurs at approximately 4,000 hours (45% annual capacity factor). In other words, the high variable cost of operating a CCGT plant make it relatively more expensive than a nuclear plant if it is required to operate more than 4,000 hours a year. Conversely, the CCGT plant will be lower cost than a nuclear plant if operated less than 4,000 hours a year.

Figure 2 below shows the same results, but expressed in $/MWh on a LUEC basis, again assuming a discount rate of 4%. LUECs are a method of expressing the cost to produce a unit of electricity across different generation technologies. LUECs are calculated using the total cost required to generate electricity, including fixed and variable operating costs (including fuel) and a return on and of the capital employed to build the generation facility. These total costs are forecast over the life of the asset and then discounted back to produce a levelized amount expressed in a unit of electricity, in this case dollars per MWh.

Figure 2: Breakeven Analysis on LUEC Basis



Source: OPA

It should be noted that the plot for the nuclear unit is much more sloped than it was under the previous $/kW-year graph. As a nuclear plant is able to spread out its high fixed costs over greater and greater production (MWh), its overall cost per MWh produced will decline. Once again, the results in Figure 2 indicate that a nuclear plant will be lower cost than a CCGT plant if it is operated more than 4000 hours per year. Conversely, a CCGT plant will be lower cost than a nuclear plant if the nuclear plant is operated less than 4,000 hours per year. The above analysis is based on a gas price of $8/MMBtu, a discount rate of 4% real, and on the data above in Table 1, but before any consideration for uncertainties associated with the assumptions used.

In order to determine the appropriate amount of baseload resources as a percentage of the total mix of generation resources in the Plan, it is necessary to examine the Ontario system load shape. Figure 3 shows the forecast load duration curve for the Ontario electricity system in 2015[7]. This load duration curve indicates that the CCGT – CANDU 6 breakeven point of 4000 hours per year would equate to 19,000 MW of demand (69% of the maximum demand). In other words, in 2015, the Ontario system load is greater than 19,000 MW for 4,000 hours of the year. Therefore, a baseload resource, such as the CANDU 6 nuclear plant, that needs to operate at least 4,000 hours per year to be economic relative to a CCGT plant, could be used to meet up to 19,000 MW of the Ontario system load[8].

A similar analysis is described in a paper produced by Professor Paul Joskow at MIT[9]. In this paper, Professor Joskow performs a breakeven analysis and overlays the results from this analysis onto a load duration curve to identify the most efficient allocation of generating technologies for a specific load level. He concludes that:

"The lowest cost mix of investments in generating technology can [then] be determined by "fitting" the total cost of building and operating each generating technology at alternative

---

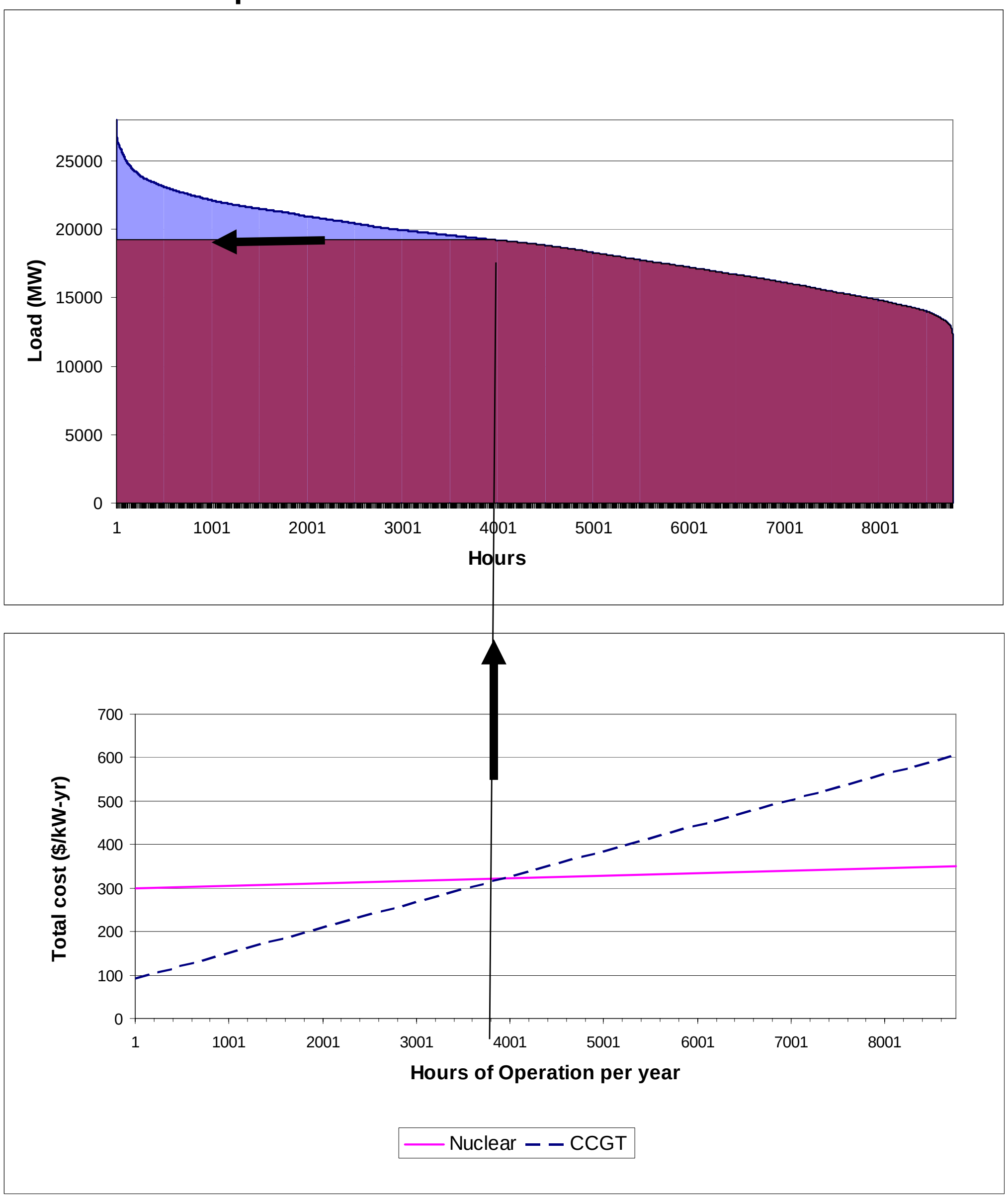
[7] The load duration curve for 2015 was selected since it is expected to be the first year in which coal-fired generation will be fully phased-out. Given the absence of this resource that comprises a significant portion of the portfolio, it will be important to plan for a proper mix of generation resource types to meet the load demands of 2015 and future years. As outlined later in this report, a sensitivity analysis was performed on the load duration curve for another year with minimal impact on the overall results. For the purposes of the IPSP analysis, Conservation is being treated as a separate resource available to meet this load and is therefore excluded from the load duration curve. (i.e., the load forecast is before any reduction from Conservation)

[8] This result compares to the 6100 hours (70% ACF) and 63% of total demand that was estimated for the Supply Mix Advice report in Section 2.6.4. The difference in results can be attributed to:
- The lower heat rate assumptions used for combined cycle in the Supply Mix Advice of 6,100 versus 7,000 in the IPSP;
- The higher discount rate of 5% used in the Supply Mix Advice versus 4% in the IPSP; and,
- The greater efficiency for combined cycle used in the Supply Mix meant that a nuclear plant would need to operate for longer periods (i.e. have a higher ACF) in order to be more economic than combined cycle. In addition, the higher discount rate from the Supply Mix would penalize the higher capital cost technology of nuclear, resulting in nuclear needing to operate for longer periods of time to be more economic that combined cycle.

[9] "Competitive Electricity Markets and Investment in New Generating Capacity" by Paul L. Joskow, MIT, June 12, 2006

utilization rates to the load duration curve for the system (since electricity cannot be stored)"

Figure 3: Baseload Generation Requirement (19,000 MW) in 2015 under Deterministic Assumptions



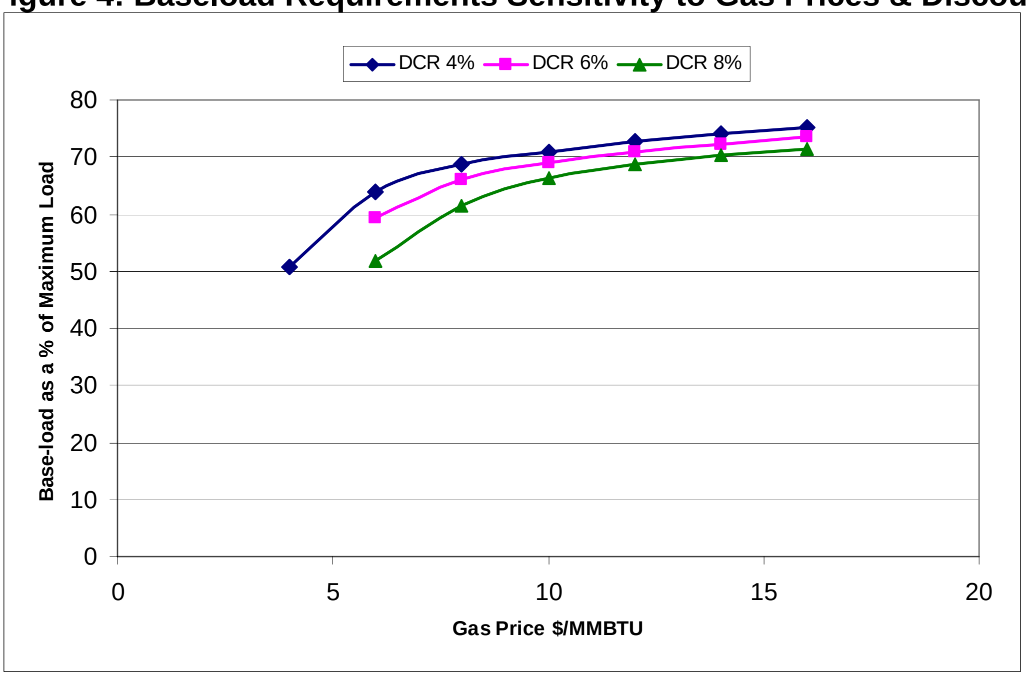
Source: OPA

4.1 Consideration of Uncertainties

The above results are particularly sensitive to the gas price used in the analysis and the discount rate used. To test this sensitivity, we have conducted both scenario analysis and Monte Carlo simulation analysis to determine how the results change as discount rates and gas prices change.

Figure 4 shows the results of a sensitivity analysis where the breakeven percentage of maximum load changes as discount rates and gas prices change. The appropriate percentage of maximum load met by baseload resources decreases as discount rates increase, due to the increased cost of nuclear plant. Conversely, the breakeven percentage of maximum load met by baseload resources such as nuclear increases as gas prices increase.

Figure 4: Baseload Requirements Sensitivity to Gas Prices & Discount Rates



Source: OPA

It can be seen that for gas prices above $8/MMBtu the results converge into the range of 65 to 75% of maximum load.

A second sensitivity was conducted on the life of the assets compared. The base case analysis assumes that the CANDU 6 nuclear and CCGT plants have asset lives of 40 and 20 years respectively. However, it is not certain that a future owner of these plants will choose these same time frames to depreciate the asset, and if these asset lives change, the relative advantage between these plants will change as well. Therefore, we have tested the sensitivity of the baseload composition results to changes in the asset life, assuming that nuclear assets have a shorter life of 30 years and CCGT life is extended to 30 years. In the case of nuclear at a 30 year life, no re-tubing costs were included. The results are shown in Table 2 below.

Table 2: Sensitivity of Results to Changes in Asset Life

	Life of Asset (years)		Baseload as a % of Maximum Load
	Nuclear	**CCGT**	
Base case	40	20	69
Nuclear shorter life	30	20	67
CCGT longer life	40	30	68
Nuclear shorter life and CCGT longer life	30	30	66

Source: OPA

The impact on baseload composition is minimal (66-69%) due to the relatively flat profile of the mid-range of the load duration curve.

4.2 Monte Carlo Simulations

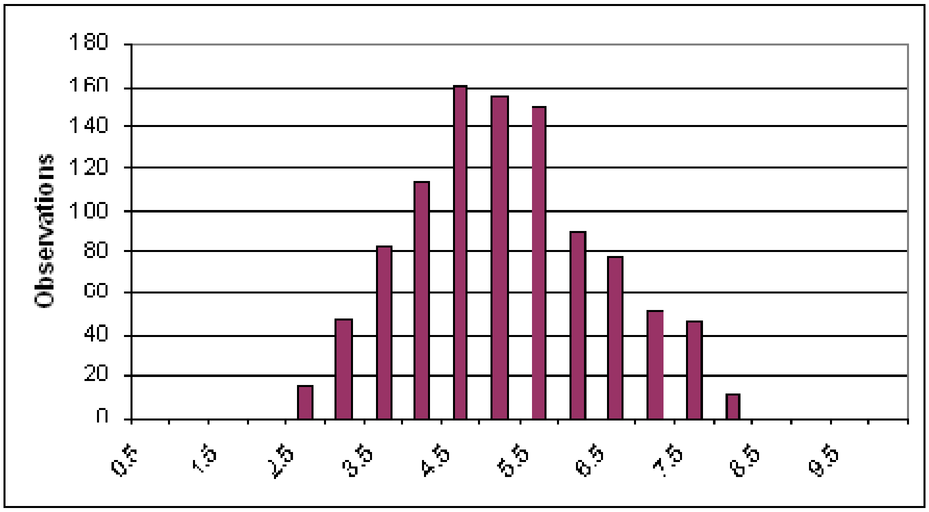
To determine the impact of assumption uncertainty, we have also performed Monte Carlo simulations, with random draws of the key input variables of capital cost, gas prices and discount rates[10]. To model the uncertainty associated with the inputs of nuclear capital costs and gas prices, we have used the probability distributions that were developed for the Supply Mix Advice[11]. These distributions were triangular and lognormal for nuclear capital costs and natural gas, respectively. In addition, we have factored in uncertainty in the

[10] Note that asset life was not included in the Monte Carlo analysis since this is likely an either/or decision rather than a range of possible outcomes for the other variables tested.

[11] Details of how these distributions were derived can be found in Section 4.1 of the Supply Mix Report entitled Navigant Consulting PSM Report Final

social discount rate using a triangular shaped probability distribution based on the historical range of values of the ten year Canada bond real yield over the period 1982 through 2006.

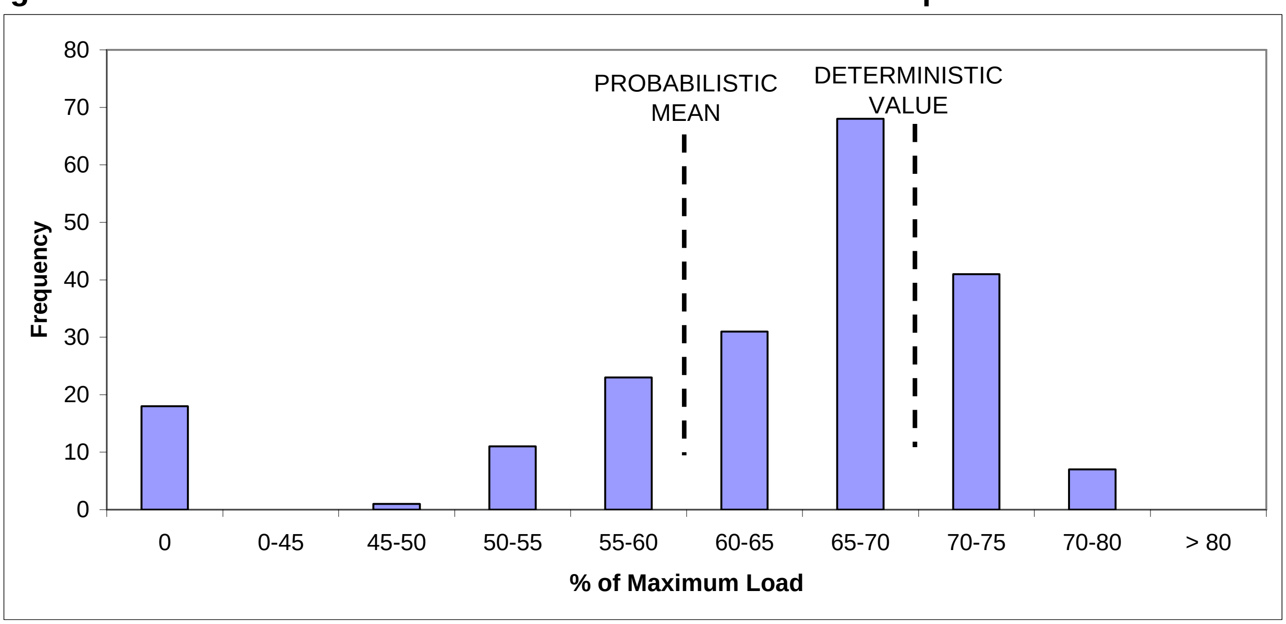
Figure 5: Observed Distribution of Real 10 Year Canada Bond Yields



Source: OPA

As outlined above, the range is roughly from 2.5% to 8.5% with 4.7% as the average.

Figure 6: Monte Carlo Simulation Distribution of Baseload Requirements



Source: OPA

Figure 6 illustrates the results of 200 simulations and the most likely requirement for available baseload resources of about 65-70% of the maximum load; however, due to the fact that the outcomes are skewed negatively, the mean requirement is lower at 60%. Note that the observations showing zero percent of maximum load at the far left of the graph represent those random draws where either nuclear is very expensive or gas very cheap, such that nuclear is not more economic than CCGT under any operating circumstance. A similar analysis was performed on the load duration curve for the year 2027, and the mean baseload requirement increased by one percent to 61% of maximum load.

4.3 Baseload Requirements Summary

On a deterministic basis, this analysis would indicate that baseload resources should be available to meet 69% of maximum load for Ontario. However, after consideration of the uncertainties associated with assumptions used in the analysis, the percentage declines to 60% of maximum load. This is equivalent to a breakeven number of hours of 6300 (or the load that exists for 72% or more of the time). It demonstrates that the nuclear-CCGT breakeven point is more sensitive to capital cost and discount rate variations than gas price volatility which tends to reduce the contribution of nuclear generation to meet baseload requirements.

The analysis has also shown that using nuclear technology as the marginal baseload resource may be less desirable under circumstances where:

- Natural gas prices remain low for extended periods of time;
- Interest rates remain high for extended periods of time; or
- There are no incremental costs associated with the environmental impacts from fossil fuel-fired resources such as CCGT.

It should also be noted that the operational limitations of the different technologies has not been considered, particularly the inflexibility of baseload resources. Such considerations may require that less than 60% of maximum load be met by baseload resources.

5.0 ECONOMIC DEFINITION OF A PEAKING PLANT

This analysis assumes that a simple cycle gas turbine plant will be the primary technology used to supply incremental peaking resources in the Plan. The economics of an SCGT plant has been compared to an intermediate resource technology, in this case a CCGT plant, to determine the appropriate amount of peaking resource within the total Plan generation resource portfolio. It should be noted that the estimated percentage of peaking resources resulting from this analysis includes other peaking resources such as storage hydro or Conservation, and is not intended to imply that all peaking resources would be SCGT units. It should also be noted that there are a range of SCGT with different costs and characteristics. The assumptions for SCGT units and CCGT units used are based on the NCI Cost of Entry study[12]. Note that these assumptions do not consider the environmental impact of the different technologies or quantify the associated cost.

Table 3: Peaking Analysis Resource Assumptions

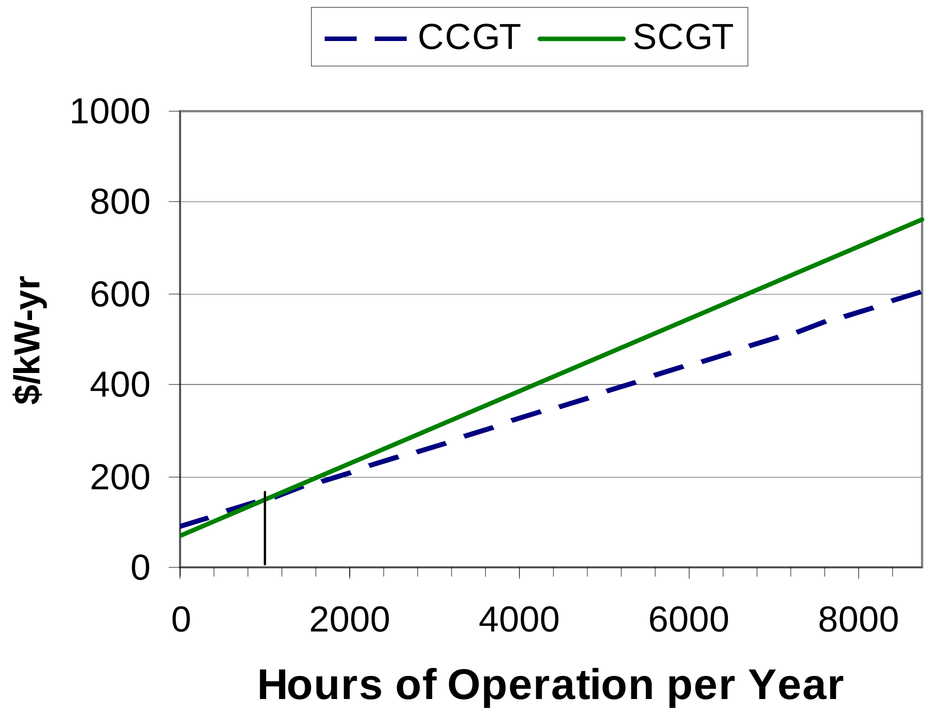
	CCGT	SCGT
Unit capital cost ($/kW) (ex idc)	924	665
Construction time (years)	3	2
Accounting life (years)	20	20
Efficiency (BTU/kWh)	7000	9500
Variable OM&A($/MWh)	2.75	3.5
Fuel cost ($/MWh)	56	76
Fixed OM&A ($/kW-yr)	17	16

Source: NCI

Figure 7 shows a breakeven analysis of an SCGT plant versus the more efficient, but more expensive to build CCGT plant.

[12] Evaluation of Costs of New Entry, Study by Navigant Consulting Inc. February 2007.

Figure 7: Breakeven Analysis of Combined Cycle Gas Turbine Plant vs. Simple Cycle Gas Turbine Plant

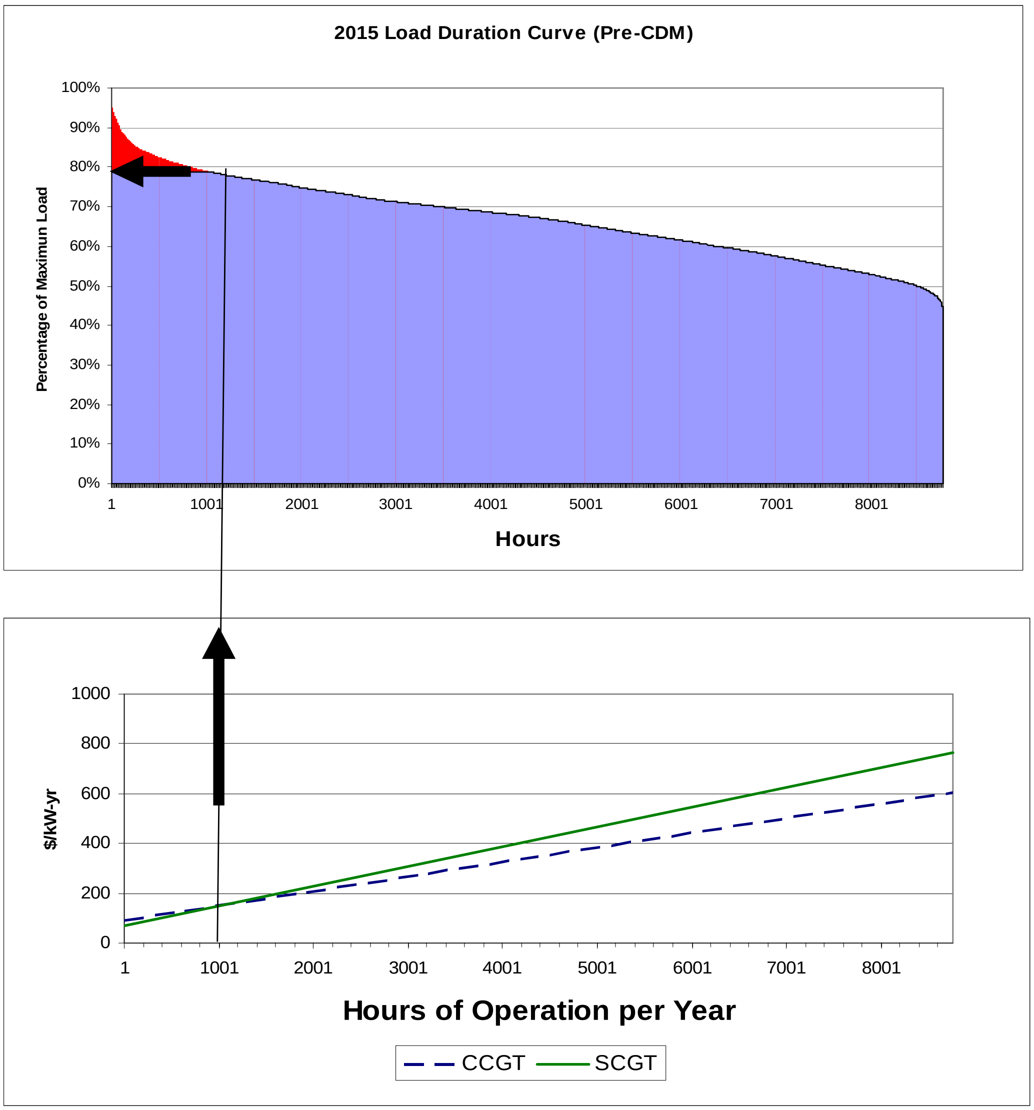


Source: OPA

The analysis shows that a plant would have lower total costs provided it operates less than 1051 hours per year (12% ACF). The SCGT plant has lower fixed costs but a higher heat rate, and therefore, as the number of operating hours increases, its costs begin to exceed that of the CCGT unit due to the increased quantity of fuel burned. Conversely, the higher fixed costs negatively impact the economics of the CCGT plant as its number of operating hours decreases.

Transferring the results of the breakeven analysis to the same 2015 load duration curve (excluding Conservation), as was used for the baseload breakeven analysis, indicates that about 21% of the maximum Ontario load could be met economically from peaking plants.

Figure 8: Peaking Generation Requirements under Deterministic Assumptions



Source: OPA

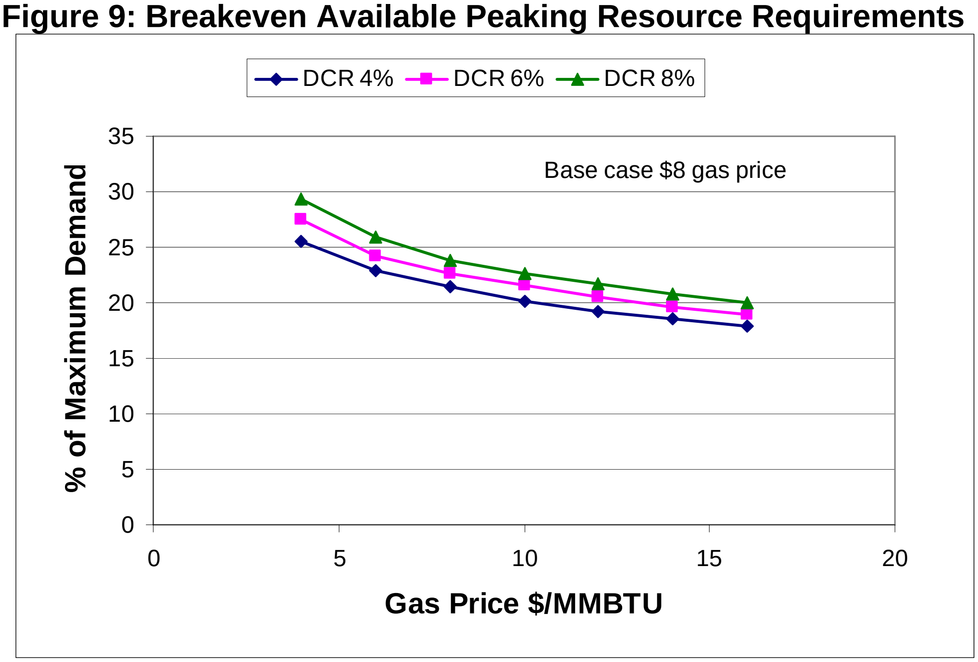
Therefore, a peaking resource such as an SCGT plant is more economical than a CCGT plant that is operated less than 1051 hours (12% of the time), and should be used to meet the highest 21% of the Ontario system load.

5.1 Consideration of Uncertainties

The technologies outlined in this analysis are continually built throughout the world and as such, the assumptions used are subject to less uncertainty than the calculation of baseload requirements. In addition, both plant types use the same fuel so their changes in variable costs are closely aligned as gas prices change. Notwithstanding these facts, an analysis was conducted to determine the sensitivity of the results to changes in the key assumptions.

Figure 9 shows how the percentage of maximum load for peaking resources varies as discount rates and gas prices change. The appropriate percentage of maximum load met by peaking resources increases as discount rates increase, due to the increased cost of the CCGT plant. Conversely, the appropriate percentage of maximum load met by peaking resources decreases as gas prices increase, due to the higher heat rate for an SCGT plant. It can be seen that the capacity requirements are relatively insensitive to the discount rate used.

Figure 9: Breakeven Available Peaking Resource Requirements



Source: OPA

A second sensitivity test was conducted on the life of the assets in question. The base case analysis assumes that the SCGT and CCGT plants have asset lives of 20 years each. However, it is not certain that a future owner of these plants will choose these same time frames to depreciate the asset, and if these asset lives change, the cost to operate these plants will change as well. Therefore, we have tested the sensitivity of the baseload composition results to changes in the asset life, assuming that either asset could have a longer life of 30 years. The results are shown in Table 4 below.

Table 4: Sensitivity of Results to Changes in Asset Life

	Life of Asset (years)		**Breakeven Peaking Plant as a % of Maximum Load**
	CCGT	**SCGT**	
Base case	20	20	21
CCGT longer life	30	20	16
SCGT longer life	20	30	24
Both longer lives	30	30	20

Source: OPA

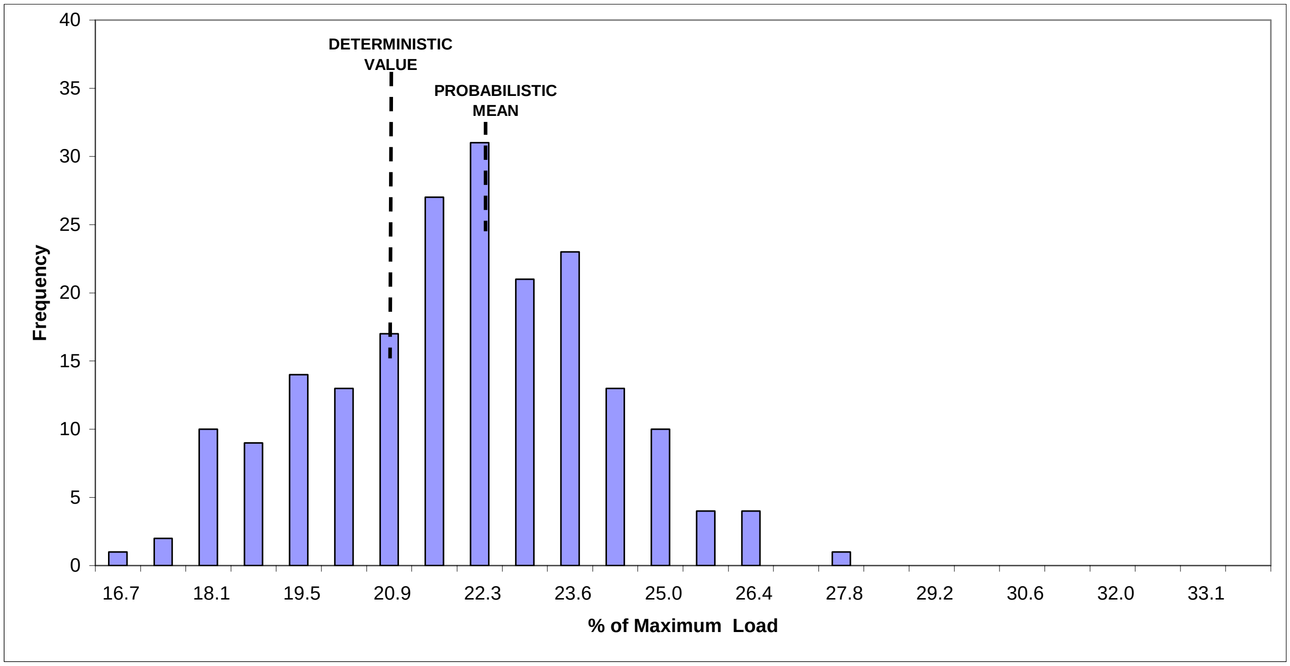
The results for peaking plants are more sensitive to changes in asset life than under the baseload analysis. The more sloped profile at the top of the load duration curve results in more significant changes to peak asset composition.

5.2 Monte Carlo Simulations

To study the effect of the uncertainties we have also performed Monte Carlo simulations with random draws of the key input variables of capital cost, gas prices and discount rates. To model the uncertainty associated with the inputs of capital costs and gas prices, we have used the probability distributions that were developed for the Supply Mix Advice. In addition, as in the baseload analysis, we have factored in uncertainty in the social discount rate using a triangular shape and distribution based on the historical range of values of the 10 year Canada bond yield over the period 1982 through 2006, adjusted for inflation. The range is roughly from 2% to 8% with 4.7% as the average.

Figure 10 shows the results of 200 simulations to determine the percentage of maximum load for peaking resources. This resulted in the probability distribution for available peaking capacity requirements with a mean of 22%.

Figure 10: Monte Carlo Simulation Distribution of Peaking Requirements



Source: OPA

5.3 Peaking Requirements Summary

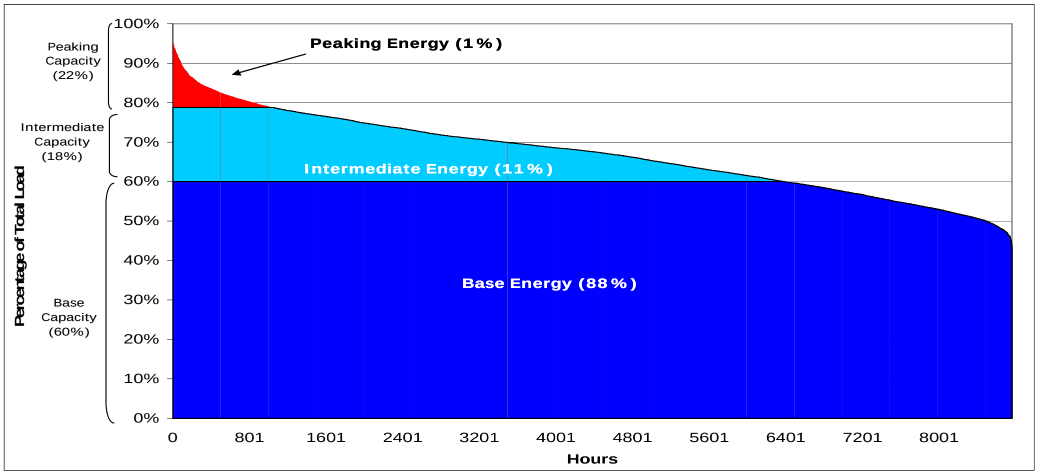
On a deterministic basis, this analysis would indicate that peaking resources should comprise approximately 21% of maximum load for Ontario. After consideration of the uncertainties associated with assumptions used in the analysis, the percentage increases slightly to 22% of maximum load. This is equivalent to planning a maximum of 1226 operating hours per year (or the load that exists for 14% or less of the time). It demonstrates that the CCGT-SCGT breakeven point is more sensitive to capital cost and discount rate variations than gas price volatility which tends to increase the contribution of SCGT generation to meet peaking requirements.

It should be noted that this study has not addressed the need for reserve requirement to cover extreme conditions and other planning contingencies. This would lead to the need for extra resources. The study has also not examined the requirement for peaking plant to meet rapid changes to generation requirements due to either changes in load or unexpected changes in output of other generation resources.

6.0 CONCLUSION

As outlined above, an efficient power system requires a proper allocation of supply between baseload, intermediate and peak supply components. However, in order to determine the proper allocation of resources, the analysis required a number of assumptions to be identified regarding the cost drivers for the various types of generation technology to be used in Ontario. These assumptions naturally contain varying levels of uncertainty and it was prudent to subject the original deterministic results to both scenario and simulation analysis to understand how this uncertainty impacts the results. After accounting for the uncertainty associated with key assumptions, the appropriate allocation of baseload intermediate and peaking resources was determined to be 60%, 18% and 22% of maximum load respectively, as shown in Figure 11 below. The corresponding proportions of total energy are also shown in Figure 11, and are summarized in Table 5 below.

Figure 11: Summary Baseload, Intermediate and Peaking Requirements



Source: OPA

Table 5: Proportion of Total Energy met by Base, Intermediate and Peaking Resources

	Base	Intermediate	Peaking
% of total energy	88	11	1

Source: OPA

It is important to note that the composition of each category would include other resources in addition to those used in the analysis, and that the operational limitations of certain technologies was not within the scope of this analysis.

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EB-2007-0707 Exhibit I, Tab 31, Schedule 85, Attachment 1 and 2

The Social Discount Rate for Ontario Government Investment Projects

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Ontario Ministry of Finance
Updated January 2007

Introduction

Benefit-cost analysis is a way to make rational comparisons between alternative investments to assess whether they are worth undertaking. Since these investments have benefit streams that extend over long periods of time, it is necessary to calculate their present value by taking into account the time value of money. This rate of return, conceptually similar to an interest rate, is referred to as the discount rate.

For private corporations making such calculations, the discount rate is a relatively straightforward calculation of the actual cost of funds, being a weighted average of return on equity and interest on debt.

However, in the case of the government projects, the use of the actual borrowing rate as the discount rate can lead to misleading conclusions. The Ontario Government is able to borrow large sums of money at low interest rates, but this interest rate is not a true measure of the economy's opportunity cost of capital.

Unlike a corporation, the government's credit rating does not derive from its balance sheet, and it is able to borrow money primarily due to its power to collect revenue through taxation. If it is used as the discount rate for evaluating government investment projects, it may lead to inefficient use of the government's capital.

The social discount rate (also known as the economic cost of capital) seeks to mimic the rate of return that would be earned on private sector investments. Inefficiencies in the government's use of capital are minimized by requiring government investments to meet a rate of return hurdle similar to what is earned in the private sector.

Suppose that the government can borrow at 3% because there are some investors who need to put a portion of their funds into a very low risk instrument. Should the government treat 3% as its discount rate, and undertake a road project whose benefits equal costs at a discount rate of 3%?[1]

The answer would generally be no. In order to make the citizens as well off as possible, the government should invest its resources where it has the opportunity to earn the highest rate of return.

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[1] In a political environment where the government is committed to working down its debt rather than adding to it, as is the case presently in Ontario, the interest rate clearly is not the opportunity cost. The implicit desire of the electorate to control the debt to GDP ratio is reflected in the *Fiscal Transparency and Accountability Act.* It has sometimes been argued that additional borrowing raises the interest rate. However, empirical evidence finds that this impact is quite small. Booth et al (2006) estimated that an increase of government debt equal to 1 percentage point of GDP raises the interest rate on provincial debt by only 0.6 basis points (i.e., less than a hundredth of a percentage point).

In principle, the government has open to it the same opportunities to make investments in productive enterprises as the private sector has, and therefore the potential rate of return on government investments should be equal to a proxy for the rate of return earned on capital in the private sector.[2]

Even if the government had a large budget surplus, the opportunity cost argument would still apply. The government does not own this money, and one of the alternative uses for it is to cut taxes to give money back to citizens, who can invest it at this higher rate.

Should Risk be Reflected in the Benefit-Cost Stream or the Discount Rate?

Risk is always a key factor in the analysis of the cost of capital. Once risk is allowed for, it is fairly obvious that the government's borrowing rate is not the opportunity cost of capital.

The government can borrow at a low interest rate only because lenders rely on the government's good faith and taxing power to repay the debt. However, the government as investor faces risks of loss on its investment in productive assets which may approach that of the private sector. In reality, any kind of investment is risky, including public investment projects that sometimes are misdirected or fail to operate as planned.

The exception, where a lower opportunity cost of capital should be allowed for than in the private sector, is where the government itself is the main source of risk from the viewpoint of a private sector investor, such as for regulated products. In this instance, the government as both regulator and investor may be able to avoid some of the risk that an outside investor would face.

If a particular project has an identifiable specific type of risk (e.g., environmental damage), the correct way to take this into account is to include a notional dollar cost of this risk (an estimated "insurance premium") to the future stream of costs, so as not to create a bias in favour of alternatives whose benefit stream is weighted toward the present.[3]

Estimate of the Private Sector Return on Equity Capital

Statistics Canada publishes data on the average rate of return on equity for corporations going back to 1988. The average over a long period is used, to smooth out the volatility of profits that occurs over the course of the business cycle.

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[2] The U.S. Office of Management and Budget (Circular A-94) defines the distinction as being between functions that are internal to government versus those that provide external benefits. The former are discounted at the government's borrowing rate, while the latter are discounted at a recommended social discount rate of 7 percent: "Some Federal investments provide "internal" benefits which take the form of increased Federal revenues or decreased Federal costs. An example would be an investment in an energy-efficient building system that reduces Federal operating costs. Unlike the case of a Federally funded highway (which provides "external" benefits to society as a whole), it is appropriate to calculate such a project's net present value using a comparable-maturity Treasury rate as a discount rate."

[3] H. Bierman and S. Smidt, *The Capital Budgeting Decision*, New York, Macmillan, 1980.

The pre-tax rate of return is used, to take into account the fact that the tax revenue which goes to the government is part of the income of capital from the point of view of the economy as a whole. However, since this analysis is conducted from the viewpoint of the Ontario Government, the tax rate used is the tax accruing to the Ontario Government.

The rate of return used, at 9.2 percent, is considerably higher than the historical real return from the viewpoint of a private investor. The real return on the Toronto Stock Exchange (including dividends) has averaged about 6 percent.

Interest Rate Component

In long-term financial evaluations, it is important to remember that dollars in the distant future will not have the same value as they have today, due to inflation. For more than a decade, the Bank of Canada has with considerable success pursued a target of maintaining inflation near 2 percent, but there is no certainty that this policy regime will remain unchanged in the future.

The yields on ordinary (not indexed for inflation) bonds implicitly take into account a future average inflation rate, to compensate lenders for the expected decline in the real purchasing power of the money they will get back in the future.

Financial evaluations that use future streams of costs and benefits in nominal dollars should use a nominal discount rate. They need to be reasonably sure that the discount rate and the inflation rates used in the project come from consistent sources. The preferred approach is probably to use constant dollar amounts and a real discount rate, so that inflation has been factored out of both the numerator and denominator.

In the past, it was necessary to make a forecast of the long-term future inflation rate in order to estimate the real interest rate. In fact, this is always a problem for borrowers and lenders in the nominal bond market as well, and the bond market only imperfectly predicts the future inflation rate. In the past, the bond market has tended to base its expectations of future inflation on the average inflation over the previous ten years or so, and has made substantial forecasting errors when the trend rate of inflation had a major change (Figure 1).[4]

[4] A discussion of the problem of measuring real interest rates can be found in Peter Spiro, *Real Interest Rates and Investment and Borrowing Strategy*, New York, Quorum Books, 1989.

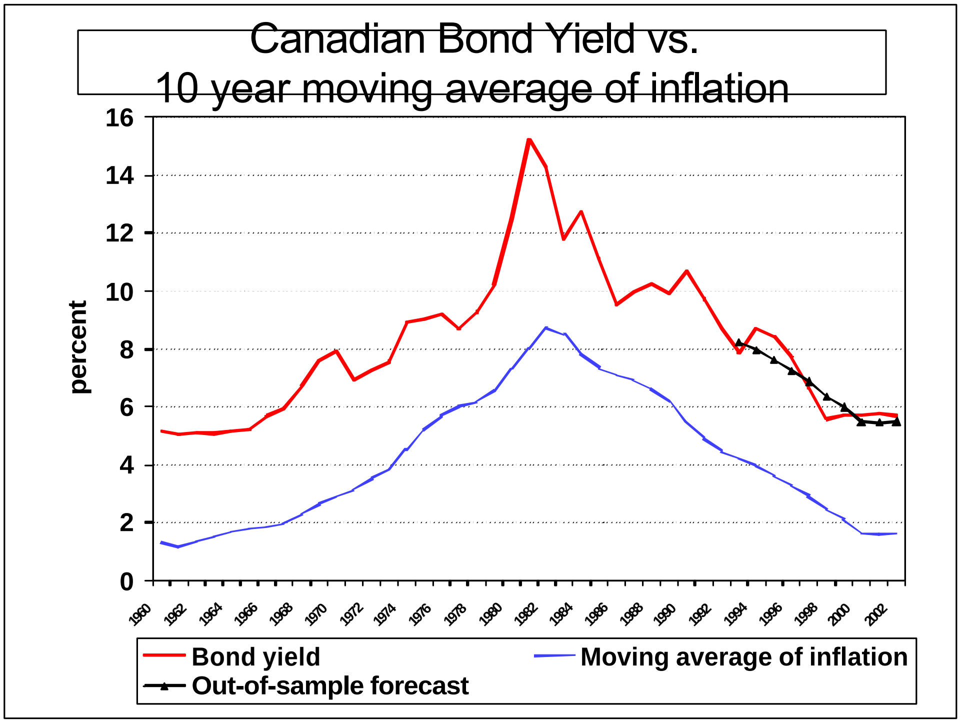

Figure 1

Fortunately, an alternative source of information now exists. This is the market yield on the Government of Canada's real return bond. These are bonds in which the value of the principal rises each year with the rate of inflation, and the yield the investor earns is applied to this rising base. The yield on this bond reflects the bond market's current forecasts of the long-term real interest rate. Along with other interest rates, this yield has been declining over the past few years, and has recently been in the area of 1.8 percent.

In the calculation below, a premium is added onto the real yield to reflect the yield differential which is typically found between Ontario Government and Federal Government nominal bonds.

Combining the Factors to Calculate the Social Discount Rate

The resulting estimate of the social discount rate is a rate of return of 5%. This is a real rate of return, since it is based on the real return on equity and the real interest rate.

A	Rate of return on equity, corporations excluding oil and gas extraction (Statistics CanadaTable 180-0002 - Financial and taxation statistics for enterprises), 1988 to 2005 average; plus Ontario's share of CIT.	9.2%
B	Ratio of liabilities to equity, non-financial industrial corporations	1.5
C	Yield on Government of Canada real return bonds	1.8%
D	Ontario Government premium	0.4%
E	Social discount rate = [A + B*(C+D)]/(1+B)	5.0%

Real versus Nominal Rates

The 5% discount rate is a real return. Therefore, when used as a discount rate, it should be applied to constant dollar values of future revenues and expenses, which do not include the effects of price inflation on the cost of activities.

If a stream of future project expenses and benefits has been expressed in nominal dollars, based on a 2% inflation rate, then this should be added onto the real discount rate to arrive at a nominal discount rate of 7%.

Sensitivity Testing

The most significant risk that needs to be taken into account directly in the use of the discount rate is the uncertainty in the estimation of the cost of capital itself. Based on past volatility in rates of return, it is suggested that a range of plus or minus 2 percentage points around the central estimate of the discount rate is appropriate for sensitivity testing for long-term investment projects (20 years or more), while for short-term investments a lower range of uncertainty might be appropriate.

The conceptual reason for this uncertainty is that the government acquires the debt and locks itself into a long-term obligation for a long-term project. Whether it is actually paid for through taxes or borrowing does not make a difference from the opportunity cost viewpoint. The longer the locked-in obligation to own and/or pay for the project, the greater the risk of "regret" that it was chosen given changing investment opportunities in the economy. This is analogous to an investor buying a twenty year bond today with a 4% yield, and regretting the decision two years later when yields have risen to 6%.

Given the diverse nature of the government's debt portfolio, with a mix of short and long-term financing, it is rare that a particular bond issue can be identified as being made directly as the result of a decision to invest in a particular project, and so it may be difficult to argue that the cost of capital is really locked in at current borrowing costs.[5]

The risk of higher future interest rates may be particularly relevant in periods, such as the present, when the real interest rate is below long-term historical averages.

Symmetrically, there is a possibility of falling rates of return on capital. This is particularly relevant in periods when the current cost of capital is above the historical average. For example, in contemplating the building of a new highway or hospital (a long-lived asset) when current borrowing rates are high, it is appropriate to consider that rates of return may fall substantially over the lifetime of the project.

Other things equal, a project that has a positive net present value at 7 percent is better than one that is only viable at 5 percent. However, there are obviously a great many uncertainties through all phases of an investment analysis, and a considerable amount of judgement needs to be applied. A project that appears to have a positive present value only with a low discount rate such as 5 percent is in a gray area, but it might be possible to justify it if there is a potential for large benefits of a type that are hard to quantify. The discount rate is just one factor in a project evaluation, and it is important to estimate the cost and benefit streams as rigorously as possible.

The Social Discount Rate Should be Reviewed Annually

There has been a tendency for some government agencies to issue a discount rate and then never review it, as if the discount rate was a constant like the value of *pi*. The Treasury Board of Canada has been prescribing an unchanged 10 percent real social discount rate for federal government projects since 1977.[6] The source of this estimate is Jenkins (1977), and it is based on data for the return on capital for the period from 1965 to 1974.

It is quite remarkable that the Treasury Board has stayed with such an old number, which is clearly obsolete. The social discount rate, as calculated by Jenkins, is not a fixed law but an empirical estimate based on current economic conditions.

Jenkins' estimate took into account factors such as the actual historical interest rates and return on capital. All of these factors can change considerably as world financial market conditions change. The high real interest rates of past decades have given way to very low real

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[5] Even though the government can lock in the current interest rate on one particular bond issue, it always has bond issues rolling over, and the risk that future refinancing will have to be at a higher rate can be viewed as part of the opportunity cost.

[6] However, it appears that this is not universally used even in the federal government. For example, in a recent regulation under the *Environmental Protection Act*, a 5 percent social discount rate was prescribed. P.C. 2003-262, 27 February, 2003, in *Canada Gazette* Vol. 137, No. 6, March 12, 2003.

interest rates currently. In 2005-06, the Ontario Government issued $1 billion of real return bonds with a maturity of 30 years at a coupon rate of 2 percent.

The recent low real interest rates are partly due to high savings rates in countries such as China which have undergone dramatic growth in income, as shown by Warnock and Warnock (2006). In the future, real rates may rise again, if demand and supply conditions change, but for investment projects undertaken in the near term, that draw on this low-cost capital, it is appropriate to use a correspondingly low discount rate.

Jenkins' estimate was also predicated on the assumption that government sector borrowing crowds out private sector investment. This was based on the view of a fixed pool of capital in a small, closed economy. This may have had some relevance in the 1960s and 1970s, but international financial market integration has increased dramatically over the past few decades.

Two recent empirical studies focusing specifically on provincial borrowing illustrate that markets can absorb quite large changes in borrowing with little impact. It has sometimes been argued that additional borrowing raises the interest rate. Booth et al (2006) estimated that an increase of government debt equal to 1 percentage point of GDP raises the interest rate on provincial debt by only 0.6 basis points, while Landon and Smith (2006) found no impact at all.

Conclusions

The social discount rate is a useful guide to discounting in benefit-cost analysis by government agencies. It reflects the widely held view that the opportunity cost of capital is higher than just the borrowing rate on government bonds.

There is a considerable degree of uncertainty about the appropriate values of financial market variables that go into the construction of discount rates. It is appropriate, therefore, to experiment with sensitivity analysis that looks at a range of possible values.

The market cost of capital that determines the social discount rate can change substantially. It is appropriate to review the value of the social discount rate at least once a year by examining changes in financial market indicators of the cost of capital.

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The Social Discount Rate for Ontario Government Investment Projects

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Updated March 2008

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Introduction

Benefit-cost analysis is a way to make rational comparisons between alternative investments to assess whether they are worth undertaking. Since these investments have benefit streams that extend over long periods of time, it is necessary to calculate their present value by taking into account the time value of money. This rate of return, conceptually similar to an interest rate, is referred to as the discount rate.

For private corporations making such calculations, the discount rate is a relatively straightforward calculation of the actual cost of funds, being a weighted average of return on equity and interest on debt.

However, in the case of government projects, the use of the actual borrowing rate as the discount rate can lead to misleading conclusions. The Ontario Government is able to borrow large sums of money at low interest rates, but this interest rate may not be a good measure of the opportunity cost of capital.

Unlike a corporation, the government's credit rating does not derive from its balance sheet, and it is able to borrow money primarily due to its power to collect revenue through taxation. If it is used as the discount rate for evaluating government investment projects, it may lead to inefficient use of the government's borrowing capacity.

The social discount rate (also known as the economic cost of capital) seeks to mimic the rate of return that would be earned on private sector investments. Inefficiencies in the government's use of capital are minimized by requiring government investments to meet a rate of return hurdle similar to what is earned in the private sector.

Suppose that the government can borrow at 3% because there are some investors who need to put a portion of their funds into a very low risk instrument. Should the government treat 3% as its discount rate, and undertake a road project whose benefits equal costs at a discount rate of 3%?[1] The answer would generally be no. In order to make the citizens as well off as possible, the government should invest public resources where they have the opportunity to earn the highest rate of return.

There is no universally accepted method for choosing the discount rate, and a number of different approaches have been recommended, as discussed in a very comprehensive survey of the literature by Zhuang et al (2007). The choice depends on various philosophical issues and

[1] It has sometimes been argued that additional borrowing raises the interest rate. However, empirical evidence finds that from a province's viewpoint, this impact is negligible. Booth et al (2006) estimated that an increase of government debt equal to 1 percentage point of GDP raises the interest rate on provincial debt by only 0.6 basis points (that is, less than a hundredth of a percentage point). The latest international evidence similarly suggests that, for advanced countries the supply of funds is very elastic, and interest rates would only be impacted if deficits became very large, as in Aisen and Hauner (2008).

views about the sources and alternative uses of the funds. These go beyond merely empirical questions to more fundamental issues about the choices that are (or ought to be) open to various entities.

The approach taken in this paper is a compromise between alternative viewpoints. The discount rate should approximate the rate of return that could be earned on a notional balanced portfolio of financial investments, even if in practice this might not be its most likely alternative use. To earn a lower rate of return than on a passive investment could be characterized as poor stewardship. It will be seen that the numerical estimate derived for this approach is close to being half way between the high and low end of the alternative approaches to social discount rates.

Should Risk be Reflected in the Benefit-Cost Stream or the Discount Rate?

It has sometimes been argued that benefit-cost analysis should apply different discount rates in different kinds of projects, to adjust for the project-specific risk of failure in its intended achievements.

However, the general consensus in cost-benefit evaluation tends towards the view that the discount rate should not be adjusted for the risk of the investment, and that instead the dollar amounts of the future estimated benefits and costs should be adjusted to "certainty equivalents." The latest version of the Canadian Treasury Board's Benefit-Cost Analysis guide (2007) also suggests a similar approach, in which a range of scenarios representing the uncertainty of future costs and benefits is discounted.

One recent exception is Brean et al (2005), who propose a method for adjusting the discount rate for risk, focusing specifically on investments in transportation.[2]

If a particular project has an identifiable specific type of risk (e.g., environmental damage), the correct way to take this into account is to include a notional dollar cost of this risk (an estimated "insurance premium") to the future stream of costs, so as not to create a bias in favour of alternatives whose benefit stream is weighted toward the present.[3]

There is a wide range of socioeconomic factors that should be taken into account in a comprehensive benefit-cost analysis.

For example, it was argued above that government borrowing does not significantly affect the interest rate on private sector borrowing. However, financial capital is not the same as physical resources. Financial capital borrowed from abroad is useful if the incremental demand

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[2] They undertake simple regressions that relate the demand for various kinds of transportation services to GDP growth. Where the demand elasticity is greater than one, they assume that this represents a greater than average risk factor. However, this approach is not persuasive, since the more important risks about a long-term project have to do with its overall viability, and not whether it will be temporarily underused in an economic recession.

[3] H. Bierman and S. Smidt, *The Capital Budgeting Decision*, New York, Macmillan, 1980.

for physical resources can be met by using the foreign money to buy importing goods and services. Quite often this is not possible, and this has sometimes been referred to as the "transfer problem." Government projects draw on local construction resources, where bringing in foreign workers may not be practical. In periods of full employment, the government activity may lead to the postponement of private sector construction (or higher costs for these projects).

This can be a significant issue that should factor into government decision-making, but it is not obvious that the discount rate is the appropriate way to deal with it. Private sector construction spending has always been one of the most volatile components of the economy. Good macroeconomic policy would dictate that the government should be concerned about these issues and should try to stream its projects as much as possible to smooth out the fluctuations in the construction sector.

Benefit/cost analysis typically takes into account socioeconomic impacts such as job creation in the economy. The impact on construction cost inflation could also be taken into account to help signal that projects should proceed more slowly during periods of excess demand. Similarly, the positive impact that public infrastructure has on private sector productivity should be taken into account in the benefit stream.[4]

No doubt, all these factors are hard to forecast. However, the only way to evaluate the reasonableness of the forecasts for different factors is if they are laid out individually. This creates greater transparency, and in the long run better decision making, than if they are all lumped together as a miscellaneous "risk factor" in the discount rate.

Estimate of the Private Sector Return on Equity Capital

The view taken in this paper is that government borrowing does not have a material crowding-out impact on private sector investment. The opportunity cost of public funds comes from the fact that the money could instead be invested in financial markets, either directly by the government, or by the citizens it represents if they received this money in the form of lower taxes. In that case, it is an after-tax rate of return on financial capital that is relevant.

This contrasts with the view often taken in previous Canadian studies, which sought to use the pre-tax rate of return. These studies were all conducted from the viewpoint of the federal government. Even if one were to accept a crowding-out view, from the viewpoint of the Ontario government, the tax share would be quite small, reflecting its small share of the total corporate tax revenue received in Canada (about 15 percent of the total in 2005).[5]

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[4] Harchaoui et al (2004) provide a methodology for estimating these benefits.

[5] At first glance, this might be considered a "selfish" approach. However, in the absence of an explicit decision by all provinces to do differently, it is the sensible approach. Moreover, there is a widespread consensus that in recent years Ontario has been short-changed by national fiscal programs such as equalization.

One potential approach to estimating the opportunity cost would be to look directly at rates of return on equity investments in the stock market. However, this has such extreme volatility, even over time horizons as long as a decade, that it is hard to make any reasonable inference from it for long-run trends. A still imperfect, but somewhat more stable source of information about underlying fundamentals comes from looking directly at data on rates of return on business capital.

Statistics Canada publishes data on the average rate of return on equity for corporations going back to 1988. To smooth out the volatility of profits that occurs over the course of the business cycle, average data over the latest ten years (1998 to 2007) is used, and returns for the oil and gas sector are excluded. The average return on equity over this period was 9.7 percent. (The average is 8.8 percent over the whole data sample back to 1988.) As this is calculated on the book value of equity, it is a nominal rate that needs to be adjusted to reflect inflation. Subtracting 2 percent as the long-run average expected inflation rate leaves 7.7 percent.

The real rate of return derived this way, at 7.7 percent, is considerably higher than the historical real return from the viewpoint of a private investor. The real return on the Toronto Stock Exchange (including dividends) has averaged about 6 percent. Therefore, it can be considered a reasonably conservative estimate of the opportunity cost of equity capital.

Interest Rate Component

In long-term financial evaluations, it is important to remember that dollars in the distant future will not have the same value as they have today, due to inflation. For more than a decade, the Bank of Canada has with considerable success pursued a target of maintaining inflation near 2 percent, but there is no certainty that this policy regime will remain unchanged in the future.

The yields on ordinary (not indexed for inflation) bonds implicitly take into account a future average inflation rate, to compensate lenders for the expected decline in the real purchasing power of the money they will get back in the future.

Financial evaluations that use future streams of costs and benefits in nominal dollars should use a nominal discount rate. They need to be reasonably sure that the discount rate and the inflation rates used in the project come from consistent sources. The preferred approach is probably to use constant dollar amounts and a real discount rate, so that inflation has been factored out of both the numerator and denominator.

In the past, it was necessary to make a forecast of the long-term future inflation rate in order to estimate the real interest rate. In fact, this is always a problem for borrowers and lenders in the nominal bond market as well, and the bond market only imperfectly predicts the future inflation rate. In the past, the bond market has tended to base its expectations of future inflation

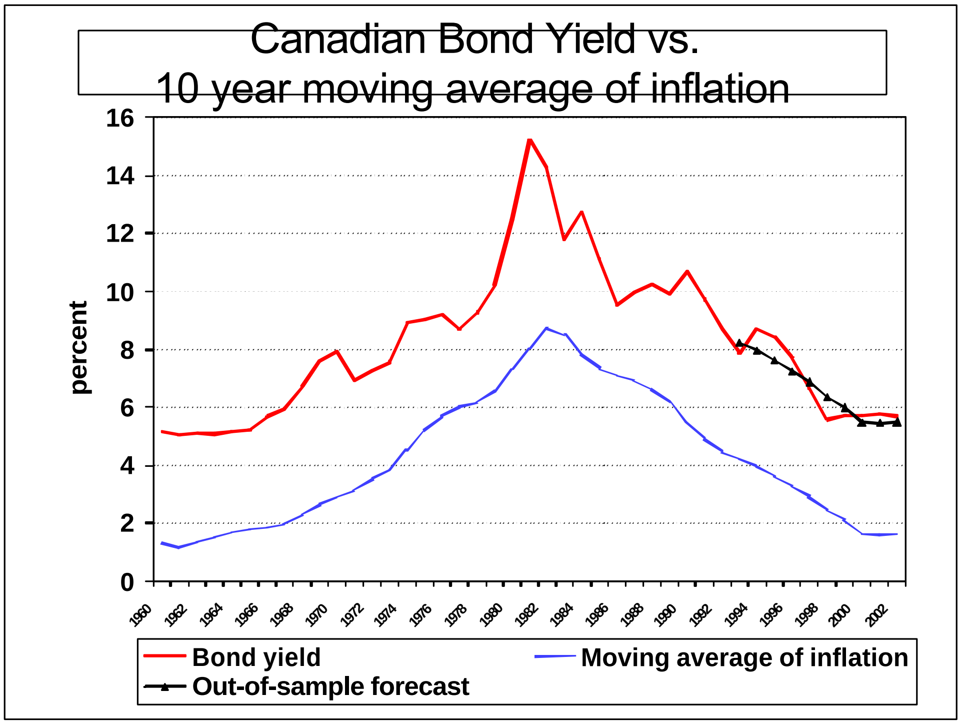

Figure 1

on the average inflation over the previous ten years or so, and has made substantial forecasting errors when the trend rate of inflation had a major change (Figure 1).[6]

Fortunately, an alternative source of information now exists. This is the market yield on a real return bond. These are bonds in which the value of the principal rises each year with the rate of inflation, and the yield the investor earns is applied to this rising base. The yield on this bond reflects the bond market's current forecasts of the long-term real interest rate. Along with other interest rates, this yield has been declining over the past few years, and has recently been in the area of 2 percent.

One might ask why this synthetic discount rate combines the Ontario Government’s borrowing rate with the private sector return on equity capital? The reasoning behind this is that the higher bond yields paid on corporate debt merely compensate lenders for the higher default risk perceived to apply to that debt. If the Ontario Government, with its lower default risk, is using the capital, the social opportunity cost is to that extent lower than when the capital is used by the private sector.[7]

This view follows the analysis of Arrow and Lind (1970), which has become one of the cornerstones of benefit-cost analysis in the public sector. Arrow and Lind argued that governments represent a kind of pooling of risk that reduces financing risk to negligible levels. This has been criticized in recent years by “perfect capital markets” theorists, who argue that the

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[6] A discussion of the problem of measuring real interest rates can be found in Peter Spiro, *Real Interest Rates and Investment and Borrowing Strategy*, New York, Quorum Books, 1989.
[7] Montmarquette and Scott (2007), in proposing a social discount rate for Quebec, similarly make use of the yield spread between Quebec and Canadian government bonds. They recommended a real discount rate of 6 percent for Quebec.

private sector effectively has access to the same kind of risk pooling through diversification in the capital markets. However, as discussed by Spackman (2001), significant legal and institutional factors exist that create a greater risk in lending to the private sector than the public sector. In practical terms, Arrow and Lind's hypothesis still seems to hold.

This issue is particularly relevant when considering the discount rate for government owned enterprises such as Hydro One and Ontario Power Generation. These companies have their own capital structure, including equity owned by the government, and borrow without an explicit guarantee on their debt. As private sector entities, they would face considerable enterprise-specific risks, not least of which would be the effects of government regulation. Shareholders would require a higher rate of return on equity to compensate for this risk. However, if the Arrow and Lind view holds, it could be argued that, when these enterprises are in the public sector, their opportunity cost of capital is the general government discount rate.

Combining the Factors to Calculate the Social Discount Rate

The resulting estimate of the social discount rate is a rate of return of 5%. This is a real rate of return, since it is based on the real return on equity and the real interest rate.

A	Rate of return on equity, corporations excluding oil and gas extraction (Statistics Canada, Cansim Table 180-0002 - Financial and taxation statistics for enterprises), 1998 to 2007 average, less 2% to convert to a real rate.	7.7%
B	Ratio of debt to equity, non-financial industrial corporations	1.0
C	Yield on Government of Ontario real return bond, maturing in 2036[8]	2.2%
D	Social discount rate = [A + B*C]/(1+B)	5.0%

Real versus Nominal Rates

As the 5% discount rate is a real return, it should be applied to constant dollar values of future revenues and expenses, which do not include the effects of price inflation on the cost of activities.

If a stream of future project expenses and benefits has been expressed in nominal dollars, based on a 2% inflation rate, then this should be added onto the real discount rate to arrive at a nominal discount rate of 7%.

[8] Yield as of March 6, 2008; supplied by the Ontario Financing Authority.

Sensitivity Testing

The most significant risk that needs to be taken into account directly in the use of the discount rate is the uncertainty in the estimation of the cost of capital itself. There are two aspects to this.

The first is simply that there are often quite long time lags, stretching to several years, between when a project is analyzed and when the construction for it takes place. Even if one can know with precision what the discount rate should be today, its appropriate value might turn out to be different at the time the bulk of the investment is made.

The risk of higher future interest rates may be particularly relevant in periods, such as the present, when the real interest rate is below long-term historical averages.

The second factor is the inherent uncertainty in any methodology for estimating the social discount rate. For example, some economists have argued that increased government borrowing makes it harder for the private sector to gain access to funds, referring to this phenomenon as "crowding-out." This was based on the view of a fixed pool of capital in a small, closed economy. This may have had more relevance in the 1960s and 1970s, but international financial market integration has increased dramatically over the past few decades.

Two recent empirical studies focusing specifically on provincial borrowing illustrate that markets can absorb quite large changes in borrowing with little impact. It has sometimes been argued that additional borrowing raises the interest rate. Booth et al (2006) estimated that a quite substantial increase of government debt, equal to 1 percentage point of GDP raises the interest rate on provincial debt by less than one-hundredth of a percent, while Landon and Smith (2006) found no statistically significant impact at all.[9]

This paper assumes that the financial crowding-out is not a material factor in the current environment. However, the econometric analysis that supports such a view can never have 100 percent certainty, and changing fiscal and financial market conditions could alter the situation.

On the downward side, there are some economists who argue on theoretical grounds for a social rate of time preference approach to the discount rate. This would be considerably lower, with a value of about 3 percent.[10] The UK government, which previously specified a social discount rate of 6 percent, has switched to a 3.5 percent rate based on the social rate of time preference (HM Treasury, 2003).

Based on these uncertainties, it is suggested that a range of plus or minus 2 percentage points around the central estimate of the discount rate is appropriate for sensitivity testing for

[9] Even if it was believed that there is some impact, it could be argued that the relevant opportunity cost for provincial government borrowing would be the impact on private sector borrowing in Ontario, which would be smaller than the Canada-wide impact that is appropriate for federal government project evaluations.
[10] Treasury Board of Canada Secretariat (2007), p. 42.

long-term investment projects (20 years or more), while for short-term investments a proportionately narrower range of uncertainty would be appropriate.

The conceptual reason for this uncertainty is that the government acquires the debt and locks itself into a long-term obligation for a long-term project. Whether it is actually paid for through taxes or borrowing does not make a difference from the opportunity cost viewpoint. The longer the locked-in obligation to own and/or pay for the project, the greater the risk of "regret" that it was chosen given changing investment opportunities in the economy. This is analogous to an investor buying a twenty year bond today with a 4% yield, and suffering a loss of capital value if market yields subsequently rise.

Other things equal, a project that has a positive net present value at 7 percent is better than one that is only viable at 5 percent. However, there are obviously a great many uncertainties through all phases of an investment analysis, and a considerable amount of judgement needs to be applied. A project that appears to have a positive present value only with a low discount rate such as 5 percent is in a gray area, but it might be possible to justify it if there is a potential for large benefits of a type that are hard to quantify. The discount rate is just one factor in a project evaluation, and it is important to estimate the cost and benefit streams as rigorously as possible.

The Social Discount Rate Should be Reviewed Annually

There has been a tendency for some government agencies to issue a discount rate and then never review it, as if the discount rate was a constant like the value of *pi*. The Treasury Board of Canada was, until very recently, prescribing a 10 percent real social discount rate for federal government projects that had not been revised for 30 years.[11] This estimate was based on data for the return on capital for the very distant past period from 1965 to 1974.[12]

These estimates took into account factors such as the actual historical interest rates and return on capital. All of these factors can change considerably as world financial market conditions change. The high real interest rates of past decades have given way to very low real interest rates currently. In 2005-06, the Ontario Government issued $1 billion of real return bonds with a maturity of 30 years at a coupon rate of 2 percent.

The recent low real interest rates are partly due to high savings rates in countries such as China which have undergone dramatic growth in income, as shown by Warnock and Warnock

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[11] However, it appears that this was not universally used even in the federal government. For example, in a recent regulation under the *Environmental Protection Act*, a 5 percent social discount rate was prescribed. P.C. 2003-262, 27 February, 2003, in *Canada Gazette* Vol. 137, No. 6, March 12, 2003.

[12] This estimate, originally found in Jenkins (1977) was recently updated in Jenkins and Kuo (2007). The latter reduced the rate to 8 percent, but the methodology continues to assume that there is considerable crowding-out of private investment. They assume relatively low elasticities of foreign capital inflows that imply considerable crowding out, but they do not provide any empirical evidence of this. Moreover, they assume that increased government debt in Canada is offset partly by equity capital inflows, with a higher capital cost than debt.

(2006). In the future, real rates may rise again, if demand and supply conditions change, but for investment projects undertaken in the near term, it is appropriate to use a correspondingly low discount rate.

Conclusions

There is a widely held view that the opportunity cost of capital is higher than the borrowing rate on government bonds. This paper has suggested a conceptual framework for establishing that opportunity cost. It implies that a real discount rate of 5 percent should be used by the Ontario government when conducting benefit/cost analysis for investment projects.

There is, however, a degree of uncertainty about the appropriate values of financial market variables that go into the construction of discount rates. It is appropriate, therefore, to experiment with sensitivity analysis that looks at a range of possible values.

The supply and demand conditions in the economy that determine the social discount rate can change substantially over time. It is appropriate to regularly review the value of the social discount rate by examining changes in financial market indicators of the return on capital.

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EB-2007-0707 Exhibit I, Tab 38, Schedule 32

VECC INTERROGATORY 32

QUESTION

Issue: A11

Reference: Exhibit D/Tab 3/Schedule 1, page 9 and Attachment 1

Preamble: Attachment 1, pages 5-7 discuss the Social Discount Rate used in the IPSP

a) Please provide a copy of the Ontario Ministry of Finance paper referenced on page 5 of Attachment 1.

b) Page 7 of Attachment 1 makes reference to "the wide range of authoritative estimates of SDR". Please provide the relevant references and the estimated SDR from each.

c) What is the OPA's understanding as to the SDR used in other Canadian jurisdictions when considering long term electricity supply planning?

d) On page 6, the OPA estimates the Rate of Time Preference for an Ontario resident. Please provide the results of a similar exercise for the following:

- A debt/interest avoidance perspective as opposed to an investment/return perspective for an Ontario resident
- An Ontario business that raises funds through debt and equity and pays taxes.

e) Is the OPA aware of any past decision by the OEB regarding the appropriate "discount rate" to be used in such analyses? If so, please provide the relevant value and reference.

RESPONSE

a) Please see response to Pollution Probe Interrogatory 85 at Exhibit I-31-85

b) Examples of relevant references include:

<u>Treasury Board of Canada Secretariat</u>

The Treasury Board ("TB") of Canada Secretariat, in its recent "Canadian Cost-Benefit Analysis Guide" (2007), recommends a real discount rate of 8% based on a weighted average of Social Cost of Capital before tax, Social Rate of Time Preference, and cost of foreign funds.

Canada Gazette

The Canada Gazette of Nov 15, 2006 (Part II, Vol. 140, No. 23) states that an energy efficiency improvement project should be evaluated using a real 7% discount rate.

United States Office of Management and Budget

The Office of Management and Budget[1] agency of the US Government recommends using 3.0% as the real rate for discounting cash flows occurring over a 30-year period.

H. M. Treasury

The report of Her Majesty's Treasury entitled *Green Book, Appraisal and Evaluation in Central Government* (January 2003) provides the "binding"[2] "guidance to UK Government departments and executive agencies that the Social Discount rate (based on Social Time Preference Rate) valued at between 3% and 3.5% be used as the standard real discount rate"[3].

U.K. Department for Business, Enterprise & Regulatory Reform,

The energy planning report of the U.K. Department for Business, Enterprise & Regulatory Reform entitled*, Meeting the Energy Challenge: A White Paper on Nuclear Power* (January 2008), concludes that a real discount rate of 2.2% should be used for long term evaluation of generation resources including investment in nuclear plants (p. 62).

Spiro Paper

In his paper, The Social Discount Rate for Ontario Government Projects, (January 2007, and updated March 2008), Peter Spiro recommends using 5% as the real SDR.

C.D.Howe Institute

In the C.D.Howe Institute's May 2001 publication "Building the Future", the paper "The Social Discount Rate in Canada" by M.A. Moore, A.E. Boardman, and D.H. Greenberg (p.122) recommends a variety of different discount rates, ranging from 2% real to 6.6% real, whether it is tax- or borrowing-financed, and whether the project has health or environmental or intergenerational implications

[1] Office of Management and Budget , OMB Circular No. A-94, Revised January 2007
[2] The UK Treasury "Green Book, Appraisal and Evaluation in Central Government" of January 2003, Preface
[3] The UK Treasury "Green Book, Appraisal and Evaluation in Central Government" of January 2003, Annex 6, point 2

c) The following is a description of the discount rates used by BC Hydro (March 2006), and Hydro-Québec (February 2008) in electricity resource system planning. Considering the way they are applied, those discount rates may be interpreted as estimates of SDR.

<u>BC Hydro</u>

In BC Hydro's 2006 Integrated Electricity Plan and Long-Term Acquisition Plan application (March 29, 2006) before the British Columbia Utilities Commission, a real average weighted cost of capital before-tax rate of 6% is used as a reference discount rate in conjunction with the alternative value of 8% for sensitivity testing.

<u>Hydro-Québec</u>

Hydro Quebec uses the equivalent of approximately 4.3% real discount rate (applied as a nominal rate of 6.45%) for its long term electricity resource planning.[4]

d) The following describes the effect of alternative views of the SDR

- One way of considering the debt/interest avoidance perspective is to assess the net benefit of reducing personal borrowing. Since interest rates on personal borrowing rates are normally higher than interest rates on personal saving, one would expect that a discount rate based on the implied benefit of reduced borrowing would be higher than the IPSP's SDR based on the implied benefit of incremental savings.
- The perspective of a taxable Ontario business raising funds through debt and equity would be specific to that firm, considering such factors as whether its current or future income puts it in a taxable position, and what proportion of its incremental funds are gained from increased debt or new share issues or increased revenue from product price increases. The after-tax cost of incremental funds to such a firm would not be appropriate as an estimate of the SDR for various reasons. Please see the response to EDA Interrogatory 6 at Exhibit I-15-6.

e) The OPA is not aware of any past decision by the OEB regarding the appropriate "discount rate" to be used in analyses of long term electricity supply planning from a societal viewpoint.

[4] Source: Decision, Regie de l'Energie, D-2008-024, 26 February 2008, p.62.

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

Interrogatory

Issue 4.1
Are the proposed 2009 and 2010 Sustaining and Development and Operations capital expenditures appropriate, including consideration of factors such as system reliability and asset condition?

Reference:

a) ExhD1/Tab3/Sched3/pp 16-17/ projects D7, D8
b) ExhD2/Tab2/Sched3/Invest.Summary/Ref.#D7&D8c)
c) Filing Requirements for Transmission and Distribution Applications, November 14, 2006 (EB-2006-0170)/Sec. 5.3.2/paragraph 3

Preamble: Reference a) and Reference b) refer to the two projects as "Non-Discretionary", and this appear to be the reasons for not showing an economic evaluation to demonstrate the economic benefits of the two projects.
Reference c) indicate that even though the net present value for a non-discretionary project need not be shown to be greater than zero, an evaluation of the economic benefits e.g., the evaluation of the reduced congestion on the system is appropriate.
Request:
Please provide an estimate of the reduced congestion attributable to the two projects over an appropriate study horizon, and listing all assumptions.

Response

The Independent Electricity Operator (IESO) provided an estimate of the reduced congestion in their System Impact Assessment Report, IESO_REP_0379 for these two projects. This report is included in the OPA's IPSP filing, EB-2007-0707, Exhibit E, Tab 3, Schedule 1, Attachment 1 which is available from the OEB's website (http://www.oeb.gov.on.ca/OEB/). A copy of the attachment is also included with this interrogatory as Attachment 1. The IESO estimate of reduced congestion on the North-South interface amounts to 700 MW. The referenced report includes all assumptions used to derive that figure.

EB-2007-0707 Exhibit E, Tab 3, Schedule 1, Attachment 1

IESO_REP_0379

Power to Ontario.
On Demand.

Independent Electricity
System Operator
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CONNECTION ASSESSMENT & APPROVAL PROCESS

SYSTEM IMPACT ASSESSMENT REPORT

For the Proposed Installation of:

Series Capacitors in the 500kV Circuits X503E & X504E at Nobel TS
SVCs at Porcupine TS & Kirkland Lake TS

Applicant: *Hydro One Networks Inc.*

CAA ID Nos.	***2004-160***	*Series Capacitors at Nobel TS*
	2006-223	*SVCs at Porcupine TS & Kirkland Lake TS*

Transmission Assessments & Performance Department

FINAL Version

Date: *15th May 2007*

System Impact Assessment Report

For the Installation of:
Series Capacitors in the 500kV Hanmer TS to Essa TS circuits, and
Static VAr Compensators at Porcupine TS and Kirkland Lake TS

Acknowledgement

The IESO wishes to acknowledge the assistance of Hydro One in completing this assessment.

Disclaimers

IESO

This report has been prepared solely for the purpose of assessing whether the connection applicant's proposed connection with the IESO-controlled grid would have an adverse impact on the reliability of the integrated power system and whether the IESO should issue a notice of approval or disapproval of the proposed connection under Chapter 4, section 6 of the Market Rules.

Approval of the proposed connection is based on information provided to the IESO by the Hydro One Networks Inc. at the time the assessment was carried out. The IESO assumes no responsibility for the accuracy or completeness of such information, including the results of studies carried out by the transmitter at the request of the IESO. Furthermore, the connection approval is subject to further consideration due to changes to this information, or to additional information that may become available after the approval has been granted. Approval of the proposed connection means that there are no significant reliability issues or concerns that would prevent connection of the proposed facility to the IESO-controlled grid. However, connection approval does not ensure that a project will meet all connection requirements. In addition, further issues or concerns may be identified by the transmitter during the detailed design phase that may require changes to equipment characteristics and/or configuration to ensure compliance with physical or equipment limitations, or with the Transmission System Code, before connection can be made.

This report has not been prepared for any other purpose and should not be used or relied upon by any person for another purpose. This report has been prepared solely for use by the connection applicant and the IESO in accordance with Chapter 4, section 6 of the Market Rules. The IESO assumes no responsibility to any third party for any use, which it makes of this report. Any liability which the IESO may have to the connection applicant in respect of this report is governed by Chapter 1, section 13 of the Market Rules. In the event that the IESO provides a draft of this report to the connection applicant, you must be aware that the IESO may revise drafts of this report at any time in its sole discretion without notice to you. Although the IESO will use its best efforts to advise you of any such changes, it is the responsibility of the connection applicant to ensure that the most recent version of this report is being used.

Hydro One

Special Notes and Limitations of Study Results

The results reported in this system impact assessment are based on the information available to Hydro One, at the time of the study, suitable for a system impact assessment of a new transmission facility.

HYDRO ONE NETWORKS Inc.

SYSTEM IMPACT ASSESSMENT REPORT

For the Installation of:

Series Compensation in the 500kV Hanmer TS to Essa TS Circuits, and
Static VAr Compensators at Porcupine TS and Kirkland Lake TS

EXECUTIVE SUMMARY

1. Introduction

With all transmission facilities in-service, operation of the generating facilities in North-eastern and North-western Ontario during peak periods is governed primarily by the existing transfer limits on the following transmission Interfaces that have been identified in Diagram Exec 1:

Interface		*Present Transfer Limit*
East-West Transfer East	[measured at Wawa TS]	325MW
Mississagi (East Circuits) Flow-East	[measured at Mississagi TS]	550MW
Flow-South	[measured at Essa TS & Otto Holden GS]	1400MW

A review of the *existing* generating facilities in the North-east of the Province, as far west as Wawa TS, indicates a total installed capacity of **3370MW**. This includes the two Prince Wind Farm Projects; the ongoing development of Yellow Falls GS; the proposed redevelopment of the Upper Mattagami River plants (27MW); as well as a nominal 25MW injection at Iroquois Falls from the Abitibi Price system.

With a transfer across the East-West Transfer East Interface at the present operating limit of 325MW, those facilities west of Mississagi TS would result in a transfer of approximately 1030MW across the Mississagi Flow-East Interface. This would exceed the operating limit of this Interface by 480MW.

The corresponding transfer across the Flow-South Interface would be approximately **2170MW**: this would exceed the present operating limit for this Interface by 770MW.

The proposed expansion of the generating facilities at the Lower Mattagami River plants, representing a net increase in capacity of 433MW, would increase the peak transfer across the Flow-South Interface to **2500MW**.

Even if the existing limit of 550MW for transfers across the Mississagi Flow-East Interface were to be respected, then the expansion of the generating facilities at the Lower Mattagami River plants could still result in a peak transfer of **2100MW** across the Flow-South Interface.

Hydro One has therefore submitted a proposal for review under the Connection Assessment process involving the installation of the following facilities:

- Static VAr Compensators (SVCs) at Porcupine TS and Kirkland Lake TS, and
- Series capacitors at Nobel SS in each of the 500kV circuits X503E & X504E between Hanmer TS and Essa TS. These are to provide 50% compensation for the line reactance.

These facilities are intended to increase the transfer capability across the Flow-South Interface to approximately 2100MW. This would then be sufficient to accommodate all of the existing generating facilities north of Sudbury together with the proposed expansion of the Mattagami River plants, while restricting transfers across the Mississagi Flow-East Interface to the present limit of 550MW.

2. Expansion of the Mattagami River Plants

To accommodate the additional output from the generating facilities on the Mattagami River it has been determined that a new 230kV busbar would be required at Little Long SS so that the two 230kV circuits to Pinard TS could be individually terminated on to the new busbar. This would then result in equal loading on each 230kV circuit and ensure that the flows would remain within their continuous summer rating.

Similarly the existing 230kV circuit that currently terminates at Harmon GS would need to be extended to Kipling GS so that the existing and the proposed generating facilities could then be distributed between the two 230kV circuits. Not only would this balance the loading on each circuit, but it would ensure that a contingency involving either of the circuits would not result in the isolation of all three generating units at any of the four generating plants.

In addition, to compensate for the increased transmission losses, it was determined that a 100MVAr shunt capacitor bank would need to be installed at both Little Long GS and Pinard TS.

These new facilities have been assumed to be an integral part of the facilities associated with the expansion of the Mattagami River plants and while they were included in the system models that were used for the analysis for this Assessment, they are not considered to be included in the facilities for which Hydro One is presently seeking connection approval.

3. Transfers across the Mississagi Flow-East Interface

The existing Mississagi Special Protection System (SPS) is presently only capable of initiating generation rejection in response to the simultaneous loss of the two of the 230kV circuits between Mississagi TS and Algoma TS (circuits A23P, A324P & X74P) or between Algoma TS and the Sudbury area (circuits S22A, X27A & X74P).

The proposed expansion of this SPS to allow generation rejection to be initiated in response to single-circuit contingencies would allow higher pre-contingency transfers to occur across the Mississagi Flow-East Interface.

However, analysis has shown that once the transfers across this Interface exceed 890MW, transient stability cannot be maintained between the generation capacity west of Sudbury and the rest of the system, following a contingency involving the 500kV circuit P502X between Hanmer TS and Porcupine TS.

This analysis has also shown that with additional reactive power support, consisting of a +300/-100MVAr SVC at Mississagi TS together with a 100MVAr shunt capacitor bank at both Mississagi TS and Algoma TS, the transfer capability across this Interface could be increased to approximately 1030MW.

This would be sufficient to accommodate all of the existing generating facilities west of Mississagi TS, including the Prince I & II Projects, together with a maximum transfer of 325MW across the East-West Transfer East Interface at Wawa TS.

4. Transfers across the Flow-South Interface

i. With the new facilities as originally proposed

With the following new facilities in-service, analysis has shown that, subject to the automatic rejection of approximately 500MW of generating capacity in the Moose River basin immediately post-contingency, transient stability for a contingency involving one of the Hanmer TS-to-Essa TS 500kV circuits could be maintained for a pre-contingency transfer of up to **2150MW** (after allowing for a margin of 10%) across the Flow-South Interface:

- the proposed series capacitors at Nobel SS, together with the SVCs at Porcupine TS and Kirkland Lake TS
- the local facilities identified for the proposed expansion of the Lower Mattagami River plants
  i.e. a new 230kV busbar at Little Long GS plus a 100MVAr shunt capacitor bank at both Little Long GS & Pinard TS

Following the automatic rejection of 500MW of generating capacity, the post-contingency transfer across the Flow-South Interface would be reduced to approximately 1780MW. Since the Power-Voltage analysis for the system conditions with the same facilities in-service as detailed above has shown that post-contingency voltage stability could be maintained for a post-contingency transfer of up to 1921MW, the requirements for maintaining transient stability would therefore be more limiting than those for voltage stability.

The enhanced transfer capability provided by the installation of these new facilities would be adequate to accommodate all of the **existing & committed** generating facilities north of Sudbury together with an increase of **433MW** in the output from the expanded Mattagami River plants, and with a simultaneous transfer of approximately **600MW** across the Mississagi Flow-East Interface i.e. approximately 50MW above the present operating limit of 550MW for this Interface.

ii. With the new facilities as originally proposed, together with additional reactive power support on the north-south corridor

With additional reactive power support at both Mississagi TS and Algoma TS, the analysis has shown that the transfer capability across the Mississagi Flow-East Interface could be increased to 1030MW. However, with the facilities as originally proposed by Hydro One, the transfers across the Flow-South Interface would still be limited to 2150MW. This would therefore mean that the transfers across the Mississagi Flow-East Interface would need to be restricted to only 600MW whenever peak transfers are being made from the generating facilities north of Sudbury.

To increase the transfer capability of the Flow-South Interface to 2500MW (after margin) so that all of the existing and committed generating facilities both north and west of Sudbury could be accommodated, together with a maximum transfer of 325MW across the East-West Transfer East Interface, the analysis has shown that additional shunt capacitor banks would be required at the following locations, with the ratings that have been indicated:

- Porcupine TS 2 x 125MVAr shunt capacitor banks
- Hanmer TS a 2nd 149MVAr shunt capacitor bank } rated at 220kV
- Essa TS a 2nd 182MVArshunt capacitor bank

With these additional facilities in place, 560MW of generating capacity in the Moose River basin would need to be rejected in response to an X503E (or X504E) contingency to maintain post-contingency transient stability. With this amount of generation capacity rejected, the resulting post-contingency transfer across the Flow-South Interface would be approximately 2040MW. Since the PV-analysis has shown that the maximum post-contingency transfer across the Flow-South Interface for which voltage stability could be maintained would be approximately 2238MW (after margin), the requirements for transient stability would therefore remain more restrictive than those for voltage stability.

Potential Impact on NPCC Utilities

For transfers of over 2000MW across the Flow-South Interface, a failure of the North-east Special Protection System (SPS) to initiate the required amount of generation rejection could result in transient and/or voltage instability, leading to separation of the system across the North-South Interface. Since the resulting resource deficiency in southern Ontario would be expected to have an adverse impact on the systems of our neighbouring utilities, this would result in that the portion of the SPS that responds to an X503E or X504E contingency being classified as a Type I SPS.

In anticipation of this future classification, it is therefore recommended that those facilities associated with X503E and X504E contingencies be fully duplicated to meet the NPCC requirements for a Type I SPS.

5. Transmission facilities north of Sudbury

With the expansion of the Mattagami River generating facilities and the incorporation of the 20MW facility at Yellow Falls GS, the flow via circuit H9K into Hunta SS was shown to increase. This has the effect of increasing the loading on circuits H6T & H7T into Timmins TS from Hunta SS so that their continuous summer ratings would be exceeded. This overloading could be further aggravated should the Upper Mattagami plants following their conversion from 25Hz to 60Hz operation be incorporated into La Forest DS, displacing some of the load supplied from this supply point.

It has therefore been recommended that the section of the 115kV circuits H6T & H7T between La Forest Junction and Timmins TS be uprated to at least 100^{O}C so that its rating would be comparable to that of the section between Tower 5 and Tower 280.

Furthermore, should the Upper Mattagami Plants be incorporated into the LV system of La Forest DS it may be prudent to increase the rating of this section of circuits H6T & H7T beyond 100^{O}C to accommodate a possible power injection into the 115kV system at La Forest DS.

5.1 Contingencies Involving the 500kV circuits north of Hanmer TS

500kV Circuit D501P between Porcupine TS and Pinard TS

The proposed expansion of the Mattagami River plants would result in a maximum transfer across this Interface of approximately **1300MW.**

With transfers at this level, generation rejection totalling approximately 1300MW would therefore be required in response to a contingency involving the 500kV circuit D501P. In addition, the 230kV circuits H22D, L20D & L21S would need to be cross-tripped. This would result in the capacitor banks at Little Long GS and Pinard TS being automatically disconnected.

In addition, the existing capacitor bank at Hanmer TS, together with the capacitor banks that have been proposed for installation at both Porcupine TS and Hanmer TS to achieve a Flow-South transfer capability of 2500MW, would also need to be tripped.

500kV Circuit P502X between Hanmer TS and Porcupine TS

Following the proposed expansion of the Mattagami River plants, the maximum transfer across this Interface would increase to approximately **1600MW**.

With transfers at this level, a subsequent contingency involving the 500kV circuit P502X would require approximately 1600MW of generation capacity to be rejected, together with the cross-tripping of the 500kV circuit D501P and the 230kV circuits H22D, L20D & L21S, to maintain post-contingency transient stability.

In addition, if further capacitor banks were to be installed to achieve a Flow-South transfer capability of 2500MW, then the new capacitor banks at Porcupine TS together with one of the capacitor banks at Hanmer TS would need to be tripped.

The rejection of 1600MW, which would represent a net resource deficiency of approximately 1500MW after taking account of the associated change in the transmission losses, would then represent the single largest contingency condition on the IESO-controlled grid and would require a corresponding increase in both the 10-minute and 30-minute operating reserves.

6. IESO-Requirements & Recommendations

As a result of the analysis performed for this Assessment, the following requirements were identified:

- Modify the existing Under-Frequency Load Shedding Schemes so that all of the loads in the area north of, and including Timmins are only associated with the Stage 2 portion of these Schemes.
- Review the protective relaying on the following circuits and modify as necessary to avoid inadvertent tripping in response to an external fault:

115kV Circuits:	D3K (Dymond TS to Kirkland Lake TS); A4H & A5H (Hunta SS to Ansonville TS); A8K & A9K (Ansonville TS to Kirkland Lake TS)
230kV Circuit:	W71D (Dymond TS to Widdifield SS)

- Obtain appropriate dynamic models for the SVCs that faithfully represent their behaviour so that additional studies can be performed to confirm that the recommended settings will avoid excessive post-contingency over-voltages at the associated busbars.
- Modify the NE Load & Generation Rejection Scheme to provide the required cross-tripping features, as well as the ability to arm the individual shunt capacitor banks for automatic tripping.

  In addition, the NE Load & Generation Rejection Scheme is to have the capability of initiating the rejection of each stage of the Prince Wind Farm development individually in response to a 500kV contingency involving either circuit X503E or circuit X504E.

  These new facilities, together with those existing facilities that are associated with an X503E or X504E contingency, are required to be fully duplicated to meet the requirements for possible future classification as a Type I SPS
- Perform tests on the NE Load & Generation Rejection Scheme to determine definitive time delays for the rejection of the various generating units covered by the Scheme for each of the contingency conditions that are respected.

  Should the time delays obtained from these tests vary significantly from those assumed in this assessment then it may be necessary to perform additional analysis to determine the effect that they would have on the post-contingency performance of the system.
- Uprate the 500kV circuits E510V & E511V between Essa TS and Claireville TS.
- Uprate the section of 115kV circuits H6T & H7T between La Forest Junction and Timmins TS.

7. Customer Impact Assessment

A Customer Impact Assessment is to be performed once a formal decision is made to proceed with the installation of the series capacitors at Nobel TS, together with the SVCs at Porcupine TS and Kirkland Lake TS.

Should any other major issues be identified through the CIA process then these will be addressed through an Addendum to this SIA Report.

8. Notification of Approval of the Connection Proposal

Subject to the completion of the Customer Impact Assessment and satisfying all of the requirements detailed in Section 6 above, the IESO has concluded that the following work will have no materially adverse effect on the IESO-controlled grid:

- the installation of series capacitors at Nobel TS in each of the Hanmer-to-Essa TS 500kV circuits to provide 50% compensation for the line reactance.

- the installation of a 230kV-connected SVC at Porcupine TS, rated at +300/-100MVAr
- the installation of a 115kV-connected SVC at Kirkland Lake TS, rated at +200/-100MVAr

It is therefore recommended that a Notification of Conditional Approval to Connect be issued for this work.

This approval is also to cover the following work:

- The uprating of the 500kV circuits E510V & E511V between Essa TS and Claireville TS
- The uprating of the section of the 115kV circuits H6T & H7T between La Forest Junction and Timmins TS
- The modification of the NE Load & Generation Rejection Scheme
- The modification of the Under-Frequency Load-Shedding Schemes in the north-east

Approval for those facilities directly associated with the following are expected to be the subject of separate Assessments and are therefore not included in this Notification of Conditional Approval:

- The enhancement of the Mississagi Flow-East Interface
- The incorporation of the additional generating facilities at the expanded Mattagami River plants, and
- The installation of additional shunt capacitor banks to increase the Flow-South transfer capability from 2150MW to 2500MW.

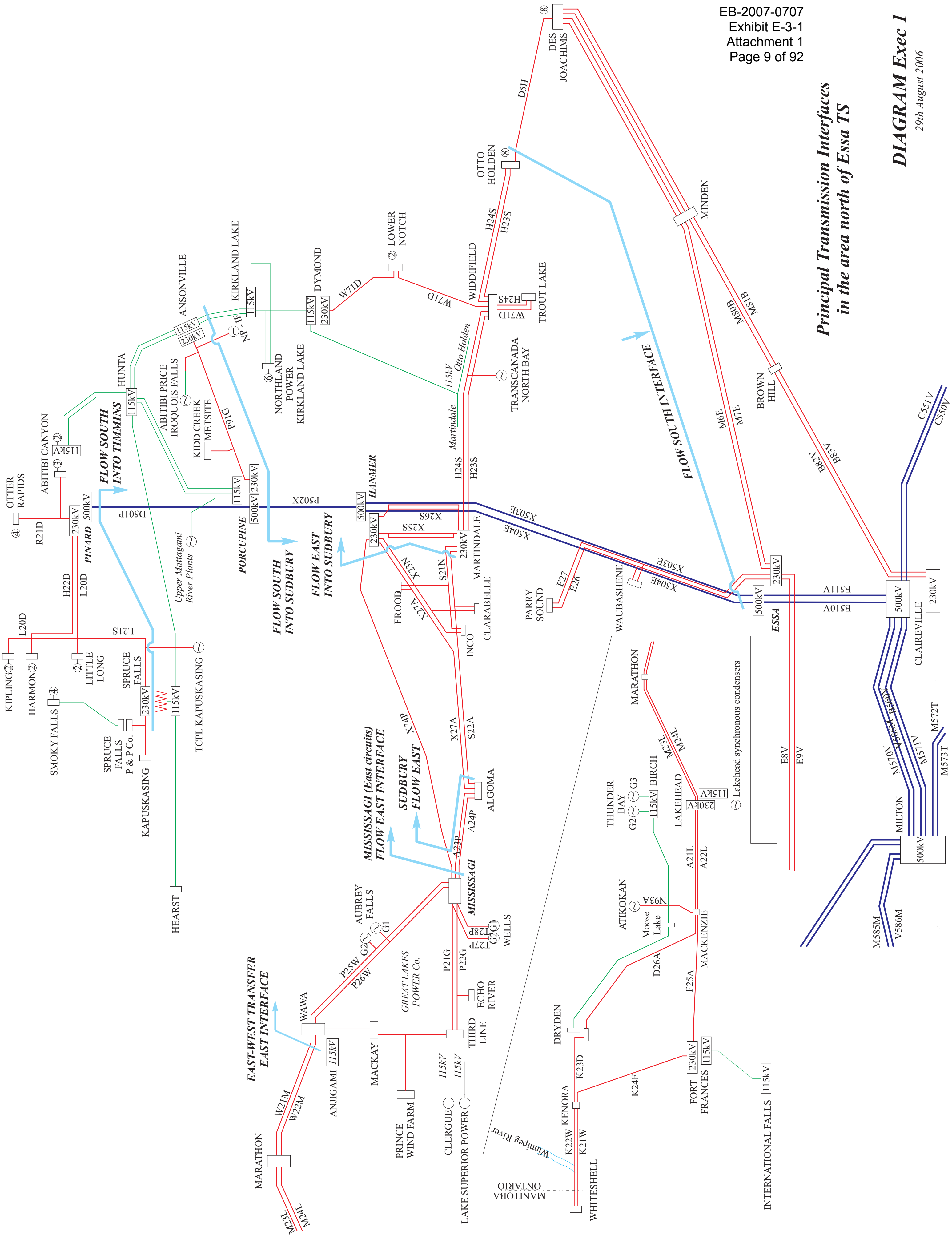
DIAGRAM Exec 1
29th August 2006
Principal Transmission Interfaces in the area north of Essa TS
DES JOACHIMS
D5H
OTTO HOLDEN
H24S
H23S
LOWER NOTCH
W71D
DYMOND
115kV
230kV
KIRKLAND LAKE
ANSONVILLE
WIDDIFIELD
H24S
W71D
TROUT LAKE
MINDEN
M80B
M81B
M6E
M7E
BROWN HILL
B82V
B83V
C551V
C550V
TRANSCANADA NORTH BAY
Otto Holden
Martindale
NORTHLAND POWER KIRKLAND LAKE
NP_IF
ABITIBI PRICE IROQUOIS FALLS
KIDD CREEK METSITE
P91G
HUNTA
ABITIBI CANYON
OTTER RAPIDS
FLOW SOUTH INTO TIMMINS
FLOW SOUTH INTERFACE
FLOW SOUTH INTO SUDBURY
FLOW EAST INTO SUDBURY
HANMER
500kV
P502X
D501P
PINARD
PORCUPINE
Upper Mattagami River Plants
R21D
H22D
L20D
L21S
X503E
X504E
X26S
X25S
X23N
X27A
S21N
FROOD
CLARABELLE
INCO
MARTINDALE
PARRY SOUND
E27
E26
WAUBASHENE
ESSA
E511V
E510V
CLAIREVILLE
KIPLING
HARMON
LITTLE LONG
SPRUCE FALLS
SMOKY FALLS
SPRUCE FALLS P & P Co.
KAPUSKASING
TCPL KAPUSKASING
HEARST
X74P
S22A
ALGOMA
MISSISSAGI (East circuits) FLOW EAST INTERFACE
SUDBURY FLOW EAST
A23P
A24P
MISSISSAGI
AUBREY FALLS
G1
G2
P25W
P26W
T27P
T28P
WELLS
GREAT LAKES POWER Co.
P21G
P22G
ECHO RIVER
THIRD LINE
EAST-WEST TRANSFER EAST INTERFACE
WAWA
ANIJIGAMI
MACKAY
PRINCE WIND FARM
115kV
CLERGUE
LAKE SUPERIOR POWER
MARATHON
W21M
W22M
M23L
M24L
E8V
E9V
M570N
V586M
B560V
M571V
M572T
M573T
MILTON
M585M
V586M
THUNDER BAY
G2
G3
BIRCH
LAKEHEAD
Lakehead synchronous condensers
A21L
A22L
ATIKOKAN
N93A
Moose Lake
MACKENZIE
D26A
F25A
DRYDEN
K23D
K24F
FORT FRANCES
KENORA
K22W
K21W
WHITESHELL
Winnipeg River
ONTARIO
MANITOBA
INTERNATIONAL FALLS

HYDRO ONE NETWORKS Inc.

SYSTEM IMPACT ASSESSMENT REPORT

For the Installation of:

Series Compensation in the 500kV Hanmer TS to Essa TS Circuits, and
Static VAr Compensators at Porcupine TS and Kirkland Lake TS

1. Introduction

Transfers to southern Ontario are already being constrained by the present operating limit of 1400MW for transfers across the Flow-South Interface. With the award of the following contracts under the Government of Ontario's initiative for new renewable resources in the north-east, the extent of the possible constraints will worsen:

- *Renewables I RFP*
    - The Prince I Wind Farm, with a capacity of 99MW, located in Prince Township near Sault Ste. Marie.
- *Renewables II RFP*
    - The Island Falls Hydroelectric Project, with a capacity of 20MW, located near Smooth Rock Falls on the Mattagami River.
    - The Prince II Wind Farm, with a capacity of 90MW, located adjacent to the Prince I Wind Farm in Prince Township.

Should approval be given to proceed with the planned expansion of the Mattagami River Plants then the transfer capability of the existing transmission facilities will need to be enhanced to address not only the existing constraints but also to accommodate the additional generating capacity from this hydroelectric development.

After accounting for the planned shut-down of the existing 52MW Smoky Falls generating station, the expansion of the Mattagami River plants is expected to result in a net increase of 432MW in the generating capacity in the north-east.

To achieve the necessary increase in the transfer capability over the transmission system south of Hanmer TS in Sudbury, Hydro One is proposing to install the following facilities:

- Series capacitors in each of the 500kV circuits X503E & X504E, to provide a 50% level of compensation. The series capacitors are to be located at Nobel TS, which is the approximate mid-point of these circuits.

- A Static VAr Compensator (SVC) at Porcupine TS, rated at +300/-100MVAr and connected to the 230kV busbar via a dedicated step-up transformer.

- A further SVC at Kirkland Lake TS, rated at +200/-100MVAr and connected to the 115kV busbar via a dedicated step-up transformer.

This assessment summarises the results of the IESO's analysis and identifies the IESO's requirements for incorporating the proposed facilities into the IESO-controlled grid.

1.1 Combined Heat & Power Contracts

Although not included in the analysis supporting this assessment, the 63MW co-generation facility at the Algoma Steel Mill in Sault Ste. Marie that was awarded a contract by the OPA on 16th October 2006 will further increase the transfers across the Flow-South Interface.

This Project is scheduled to be in full commercial operation during the second quarter of 2009.

2. *Operational Interfaces*

Diagram 1 shows the principal transmission facilities in the area north of Essa TS in Barrie. For clarity, most of the 115kV transmission facilities have been omitted together with most of the smaller generating facilities.

The principal Interfaces that govern the operation of the IESO-controlled Grid within this area are as follows:

i. Flow-South/Flow-North Interface -

Representing the combined flow on the 230kV circuit D5H, measured at Otto Holden GS, and on the 500kV circuits X503E & X504E, measured at Essa TS.

ii. East-West Transfer Interface -

Representing the combined flow on the 230kV circuits W21M & W22M, measured at Wawa TS

iii. Transfer at Mississagi Interface -

Representing the combined flow on the 230kV circuits A23P, A24P & X74P, measured at Mississagi TS.

iv. Sudbury Flow-East & Flow-West Interface - *(Measured at both Mississagi TS and Algoma TS)*

Representing the combined flow on the 230kV circuit X74P, measured at Mississagi TS, and on the 230kV circuits S22A & X27A, measured at Algoma TS.

This assessment has also adopted an arbitrary Interface to measure the combined flow into Sudbury from the west. This Interface has been designated the *Flow-East into Sudbury Interface* and it represents the combined flow on the following circuits:

v. Flow-East into Sudbury - *(Measured at both Hanmer TS and Martindale TS)*

Representing the combined flow on the 230kV circuits X74P & X27A, measured at Hanmer TS, and S22A, measured at Martindale TS.

In addition, the selection of appropriate responses within the North-east Load & Generation Rejection (NE LGR) Scheme for contingencies involving the 500kV system north of Sudbury is governed by the transfers over the following Interfaces:

vi. Flow-South (or Flow-North) into Sudbury:

Representing the combined flow on the 500kV circuit P502X, measured at Porcupine TS, and on the 115kV circuits A8K & A9K, measured at Ansonville TS.

vii. Flow-South (or Flow-North) into Timmins:

Representing the combined flow on the 500kV circuit D501P, measured at Pinard TS, and through the 230/115kV auto-transformer T7 at Spruce Falls TS.

Except for the new *Flow-East into Sudbury* Interface (item v), the present operating limits for each Interface, with all elements in-service, for the condition with flows eastwards on the East-West Ties and for flows southwards on the north-east system, are shown in the following Table:

Summary of Existing Operating Limits for the Study Area:

With all elements in-service pre-contingency

	Interface	***Present Limit***	***Critical Contingency***
•	Flow-South Transfer	*1400MW:* with 100MW of generation rejection *1300MW:* with no generation rejection	Loss of one of the 500kV circuits between Hanmer TS & Essa TS
•	East-West Transfer East	*325MW*	Loss of one of the 230kV circuits between Marathon TS & Wawa TS
•	Mississagi (East Circuits) Flow-East	*550MW*	Loss of the 230kV circuit X74P between Mississagi TS & Hanmer TS
•	Sudbury Flow-East	*No existing limit*	-
•	Flow-South into Timmins	*No existing limit -* Generation rejection required to maintain the post-contingency flow through Spruce Falls TS to the 115kV busbar to 75MW or to 20MW to the 230kV busbar AND/OR To maintain the post-contingency flow on 115kV circuit H9K to within ± 80MW.	Loss of the 500kV circuit D501P
•	Flow-South into Sudbury	*For Flow-South >650MW:* Cross-trip 500kV circuit D501P & 230kV circuit L21S and initiate generation or load rejection to maintain the post-contingency flow on circuits A8K & A9K to within 40MW south & 50MW north *For Flow-South >40MW & ≤ 650MW:* Initiate generation or load rejection to maintain the post-contingency flow on circuits A8K & A9K to between 0MW & 40MW south	Loss of the 500kV circuit P502X

3. Thermal Ratings of the Existing Transmission Facilities

The thermal ratings of the principal transmission facilities that were used in this assessment have been summarised in Appendix A.

For all of these facilities that are contained within the area north of Barrie (Essa TS), the ratings have been determined using an ambient temperature of **30^{o}C**, with a wind-speed of 4km/hr.

4. System Conditions Recorded on 30th May 2006

On 30th May 2006, when a transfer of 1411MW was recorded across the *Flow-South* Interface, a snapshot of the prevailing system conditions was taken. This Flow-South would have been slightly in excess of the existing operating limit of 1400MW for this Interface.

At the time that the snapshot was taken the primary demand was approximately 24100MW.

Diagram 2 shows the results from a load flow study that has attempted to reproduce the flows and the generation despatch that were recorded for this peak *Flow-South* transfer. For this condition, the recorded transfer across the *East-West Transfer East* Interface was **241MW**, while the net transfers into Ontario across the Manitoba/Minnesota Interconnections were 147MW

As shown, the generation capacity that was despatched within the north-east area totalled **2456MW** while for the north-west a total of 876MW of generation capacity was despatched.

As summarised below, the load flow results show a close correlation with the various transfers that were recorded:

Interface	*Recorded Transfers*	*Load Flow Results*
Flow-South Interface	1411MW	1411MW
Manitoba-Minnesota Transfer	147MW	149MW
East-West Transfer East	241MW	244MW
Mississagi (East Circuits) Flow-East	636MW	639MW
Flow-South into Hanmer	760MW	761MW
Flow-West from Dryden & Fort Frances	190MW	194MW

The Diagram also shows the loads that had to be assumed for both the north-east and the north-west, together with the resulting transmission system losses, to achieve flow distributions similar to those recorded on 30th May 2006.

For the north-west, the total load from the study was 701MW, which together with the transmission losses of 71MW, would result in a primary demand of 772MW for the area. This is approximately 11MW less than the primary demand that was actually recorded.

Similarly for the north-east, the total load from the study was 1132MW. With losses of 145MW, this would result in a primary demand of 1277MW. Since the primary demand that was recorded for the north-east was 1329MW, this suggests that the load in the load flow is understated by approximately 50MW.

It should also be noted that although the transfer of 636MW that was recorded across the *Mississagi (East Circuits) Flow-East* Interface on 30th May 2006 would have exceeded the present operating limit of 550MW for this Interface, a temporary, emergency operating limit of 650MW had been introduced specifically for the condition when all four generating units at Aubrey GS and Wells GS were in-service. Furthermore, this transfer occurred when the corresponding *East-West Transfer West* was only 241MW. Had this latter transfer been at its limiting value of 325MW, then this would have increased the *Mississagi Flow-East* transfer to approximately 720MW; approximately 170MW over the present operating limit, and 70MW over the emergency limit.

It is also worth noting that at the time the snapshot of the various system flows was taken, the Abitibi Price mill at Iroquois Falls was injecting 19MW into the system from their generating facilities.

5. Examination of the Existing System Constraints

The preceding load flow study that attempted to replicate the system conditions of 30th May 2006 was performed with the generating resources that were actually dispatched at the time the snapshot was taken. For the north-east these resources totalled 2456MW, with a further transfer of 241MW eastwards across the East-West Ties.

Since the available resources in the north-east are significantly higher and since the transfer capability of the East-West Ties is 325MW eastwards, a study was performed to determine the *Flow-South* potential of the existing generating facilities if they were not to be constrained by the present system operating limits.

For this study, and also for all subsequent studies, the IESO's reference base case for the summer-2006 was used with the load in the north-east adjusted to a value of 1192MW. This value was selected to comply with the load of 1132MW that was shown in Diagram 2, with further adjustments to account for the following:

- the discrepancy between the computed primary demand shown in Diagram 2 and the actual value that was recorded for this area, and
- the expected changes in the area load by the summer-2010, when the expanded facilities on the Mattagami River are expected to be operational.

For the north-west, no adjustment of the load was deemed to be necessary since the critical parameter in the study was the transfer on the East-West Ties. This transfer was maintained at the Interface limit of 325MW.

The generating resources that were assumed to be dispatched in this study together with the other resources that were assumed to contribute to the *Flow-South* transfer are described in the following sections.

5.1 Existing Generating Resources:

North-eastern Ontario - North & East of Sudbury

The peak outputs from the existing generating facilities in the north-east are summarised in Table 1. These include the increase in the capacity of the existing units at Little Long GS and Harmon GS resulting from the planned upgrade of their turbine runners. Once the runner upgrades have been complete, the combined capacity of the existing generating facilities in north-eastern Ontario will be **2157MW**.

North-eastern Ontario - West of Sudbury & including GLP

Table 2 summarises the peak output from the existing generating facilities in the remainder of north-eastern Ontario between Wawa TS and Sudbury. The capacity of these facilities totals **934MW**.

Total Existing Capacity in North-eastern Ontario

The existing generating facilities in north-eastern Ontario therefore have a combined capacity of **3091MW**.

TABLE 1	***NE Generation Capacity: North & East of Sudbury***		
Station	*Units*	*Total Generation*	*Summated Capacity*
Abitibi Canyon GS	230kV: 3 x 65MW	195MW	998MW *Following runner upgrades: 1019MW*
	115kV: G2 67MW G3 62MW	129MW	
Otter Rapids GS	4 x 47MW	188MW	
Little Long GS	2 x 68MW	136MW	
	Runner Upgrade: + 4MW	*140MW*	
Harmon GS	2 x 70MW	140MW	
	Runner Upgrade: + 17MW	*157MW*	
Kipling GS	2 x 79MW	158MW	
Smoky Falls GS	4 x 13MW	52MW	
Lower Notch GS	2 x 131MW	262MW	584.7MW
Otto Holden GS	4 x 28.1MW	112.4MW	
	4 x 32.6MW	130.4MW	
Coniston GS	3 x 5MW	15MW	
Crystal Falls GS	4 x 1.9MW	7.6MW	
TCPL North Bay	30.8MW + 26.5MW	57.3MW	
TCPL Calstock	43.2MW	43.2MW	524.7MW
Carmichael Falls	2 x 9.3MW	18.6MW	
Nagagami & Shekak	2 x 9.3MW	18.6MW	
TCPL Kapuskasing	30.8MW + 26.5MW	57.3MW	
Long Sault Rapids	4 x 5MW	20MW	
Cochrane	28.2MW + 14.3MW	42.5MW	
Tunis	52.7MW + 19.8MW	72.5MW	
Northland - Iroquois Falls	2 x 49.9MW + 33.7MW	133.5MW	
Northland - Kirkland Lake	3 x 17.9MW + 14MW + 19MW + 31.8MW	118.5MW	
Domtar-Eddy Espanola	2 x 8MW + 14MW	30MW	30MW
		***Total** (after runner upgrades)*	***2158.4MW***

TABLE 2	***NE Generation Capacity: GLP & West of Sudbury***		
Station	*Units*	*Total Generation*	*Summated Capacity*
McPhail GS	2 x 5.5MW	11MW	76MW
R.A. Dunford GS (High Falls)	2 x 22.5MW	45MW	
Scott GS	2 x 10MW	20MW	
Steephill GS	15MW	15MW	40.1MW
Harris GS	11.2MW	11.2MW	
Mission Falls GS	13.9MW	13.9MW	
Gartshore GS	22MW	22MW	75.7MW
Hogg GS	15MW	15MW	
Andrews GS	2 x 8.1MW + 22.5MW	38.7MW	
Hollingsworth GS	22MW	22MW	22MW
Mackay GS	2 x 9.5MW + 26MW	45MW	45MW
Clergue GS	3 x 17.3MW	51.9MW	51.9MW
Lake Superior Power	2 x 47MW + 26.1MW	120.1MW	120.1MW
		Sub-Total	***430.8MW***
Aubrey GS	2 x 81.8MW	163.6MW	163.6MW
Wells GS	2 x 120.3MW	240.6MW	240.6MW
Rayner GS	2 x 23.3MW	46.6MW	88.2MW
Red Rock GS	2 x 20.8MW	41.6MW	
Serpent River	2 x 3.6MW	7.2MW	11.2MW
Aux Sable GS	4MW	4MW	
		Sub-Total	***503.6MW***
		Total	***934.4MW***

Upper Mattagami River Plants

The existing generating facilities at Lower Sturgeon GS, Sandy Falls GS & Wawaitin GS on the upper reaches of the Mattagami River have an installed capacity of 24.3MVA. These facilities are operating at 25Hz and are incorporated into Martindale TS via the 25/60Hz frequency converter.

In the study replicating the 30th May snapshot of the system, and for which the results have been summarised in Diagram 2, it was assumed that the net injection into Martindale TS from these facilities totalled 10MW.

Ontario Power Generation has recently submitted an application for a Connection Assessment for the planned conversion of these generating facilities to 60Hz operation and for their incorporation directly into the existing 27.6kV busbar at Timmins TS. The new facilities are to have a combined capacity of 27MW and they are expected to be operational by the end-2009.

Since the redeveloped Upper Mattagami Plants are scheduled to be operational before the expansion of the plants on the lower reaches of the Mattagami River is planned to be completed, it was therefore decided to include the new facilities in all of the subsequent studies. This was done to ensure consistency between the respective study results.

Table 3 provides details of the new generating facilities that are to be installed at each of the existing stations.

TABLE 3	***NE Generation Capacity: Redevelopment of the Upper Mattagami River Plants***	
Conversion of the Upper Mattagami Plants		
Wawaitin GS	2 x 6.75MW	13.5MW
Sandy Falls GS	1 x 4.95MW	5.0MW
Lower Sturgeon GS	1 x 8.8MW	8.8MW
Total Output from the Upper Mattagami Redevelopment		***27MW***

Abitibi Price - Iroquois Falls

Abitibi Price at Iroquois Falls operates the following three generating stations that have a combined output of approximately 90MW:

- Island Falls GS Incorporated via the Abitibi Price 110kV double-circuit line into the mill
- Iroquois Falls GS Incorporated directly into the local 12kV busbar at the mill
- Twin Falls GS Incorporated directly into the local 12kV busbar at the mill

A 75MVA 230/110kV auto-transformer provides a connection to these generating facilities and to the paper-machine portion of the load at the mill from the IESO-controlled grid. The thermal-mechanical pulping load at the mill is supplied directly from the 230kV system via three 72MVA 230/13.8kV step-down transformers.

A review of Abitibi Price's operations over the past year shows that there are frequent periods, particularly during the peak winter and summer periods, as well as during freshet, when the mill is injecting up to 60MW into the IESO-controlled grid.

All of the studies apart from the initial 'snapshot' study which included a 19MW injection have therefore included a nominal injection of 25MW via the Abitibi Price connection at Ansonville TS.

Tembec Mill in Smooth Rock Falls

On 24th April 2006, Tembec announced that their paper mill in Smooth Rock Falls is to cease operations at the end of July 2006.

The mill presently has two 4MVA hydroelectric generating units and two 15MVA steam-turbine generating units providing the majority of the power requirements.

It has been assumed that once the existing steam load at the mill disappears, that the two steam-turbine units will no longer be operated. However, there would be no similar restrictions on the operation of the hydroelectric units and it has therefore been assumed that these two units will continue to operate, providing an injection of approximately 6.4MW into the system at Smooth Rock Falls.

Atikokan GS & Thunder Bay GS

When this study was started, the stated objective of the Government of Ontario was for Atikokan GS to cease operations in 2007 and for the boilers for the two steam-turbine units at Thunder Bay GS to be converted for operation on gas.

However, in mid-June 2006 the government referred the question of how best to replace the existing coal plants in the earliest practical time frame to the OPA. The future status of both Atikokan GS & Thunder Bay GS is therefore being reviewed.

Since this assessment has assumed a fixed transfer eastwards of 325MW across the East-West Ties, measured at Wawa TS, it has been assumed that it will not be especially sensitive to the particular generating facilities that are operating in the north-west.

5.2 Potential Flow-South Transfer from the Existing Generating Facilities

Diagram 3 shows the results of a study with all of the existing generating facilities operating at their maximum output; with the other resources describe above in-service; and with transfers on the East-West Ties at their maximum value of 325MW.

The total capacity of all of the generation facilities in the north-east is shown as **3151MW**. This represents the combined totals from Tables 1 & 2 (2158MW & 934MW, respectively), together with the 27MW from the Upper Mattagami Plants; 25MW from Abitibi Price Inc. in Iroquois Falls; and 6MW from the Tembec facility in Smooth Rock Falls.

This generation despatch scenario would result in a transfer of 1999MW across the Flow-South Interface; approximately 600MW over the present operating limit of 1400MW.

It should be emphasised that this scenario does not include either of the two stages of the Prince Wind Farm or the committed generating facility at Yellow Falls.

For this case, with no series compensation installed in the 500kV circuits between Hanmer TS & Essa TS, it was necessary to add the following shunt capacitor banks in order to respect minimum voltages and maintain an acceptable voltage profile:

• Mississagi TS	96MVAr	Σ 245MVAr -Rated at 220kV
• Hanmer TS	149MVAr	

Items of Note:

Although this study represents a condition that would not normally be allowed to persist because it would result in the *Flow-South* limit being violated, it does indicate some other potential limitations on the system:

- *Mississagi Flow-East*

  The flow across this Interface is shown as 840MW which would be well in excess of the present operating limit of 550MW.

  However, since this limit is based on the post-contingency voltage declines at Mississagi TS and Algoma TS following the loss of the Hanmer-Mississagi 230kV circuit, the installation of the additional shunt capacitor bank at Mississagi TS, and to a lesser extent the additional shunt capacitor bank at Hanmer TS, would be expected to improve this limit.

  In addition, the expansion of the existing Mississagi Special Protection System (SPS) to allow it to respond to single-circuit contingencies as well as to the double-circuit contingencies that are presently addressed by this SPS would further increase the transfer capability of this Interface.

- *Flows on the Hunta to Timmins 115kV circuits*

  The continuous rating for the major portion of each of these circuits is 104MVA. However, this is reduced to just 78MVA for the final spans into Timmins TS.

  The flows on these circuits are not evenly distributed due to the presence of single connections to the Kidd Creek Mine (from circuit H7T) and to LaForest DS (from circuit H6T). Consequently, at their respective Hunta terminals the flow on circuit H7T is higher than that on circuit H6T. This reverses at their respective terminations into Timmins TS with circuit H6T being more heavily loaded than circuit H7T.

While the flow on circuit H7T at Hunta SS would be marginally within its continuous rating, the flow on circuit H6T at Timmins TS would exceed its continuous rating (86MVA versus a rating of 78MVA).

5.3 Proposed Expansion of the Mattagami River Plants

The proposed expansion of the Mattagami River plants would involve the installation of a third generating unit at each of the three existing generating stations: Little Long GS, Harmon GS & Kipling GS. In addition the existing Smoky Falls generating station would be decommissioned and replaced with a new facility consisting of three new generating units.

An integral part of this plan would involve the development of a new 230kV busbar at Little Long GS as shown in Diagram 4. Not only would this new busbar ensure balanced loading on the two circuits into Pinard TS but it would also provide a suitable location for connecting a 230kV shunt capacitor bank to supply the increased reactive power losses on the 230kV system into Pinard TS.

The Diagram also shows the proposed connection of the generating facilities at each of the Mattagami River plants to the two radial circuits from Little Long SS. The arrangement that has been selected is intended to satisfy a number of objectives:

i. Achieving an approximate balance between the amounts of generating capacity incorporated on to each radial circuit.

ii. Maintaining a connection to each generating station whenever one of the two radial circuits from Little Long SS is out-of-service, and

iii. Managing the river flows following a contingency involving either of the 230kV radial circuits that would result in the automatic removal from service of all of the generating facilities connected to it.

Although not included in the new facilities covered by this Assessment for an increase in the Flow-South transmission capability, the new 230kV switching station at Little Long GS, together with a new 100MVAr shunt capacitor bank at the same location, has been assumed to be in-service in all of the subsequent analysis.

It is intended to address the development of this new 230kV switching station at Little Long GS in the companion Connection Assessment for the Expansion of the Lower Mattagami Plants.

Table 4 provides details of the new generating units that are to be installed to provide an increase in capacity of 485MW. After allowing for the retirement of the existing Smoky Falls GS, the net increase in capacity will be **433MW**.

TABLE 4	***NE Generation Capacity: Proposed Expansion of the Mattagami River Plants***		
Mattagami Expansion			
Little Long GS	1 x 70MW	70MW	*Total: 485MW*
Harmon GS	1 x 78MW	78MW	
Kipling GS	1 x 79MW	79MW	
Smoky Falls GS	3 x 86MW	258MW	
		Less existing Smoky Falls GS	*- 52MW*
		Net Increase from Mattagami Expansion	***433MW***

Modelling of the New Generating Units

The data used in this assessment to model the new generating units at each of the three existing generating stations were assumed to be the same as that for the existing equipment at these locations.

For the 86MW units that are to be installed at the new Smoky Falls generating station, the data for the existing 79MW units at Kipling GS were used and pro-rated accordingly.

6. Reference Load Flow Study

Diagram 5 shows the results of the load flow study with the following changes implemented to correspond to the expected peak operational condition during the summer-2010:

- The addition of a new 230kV busbar at Little Long GS
- The addition of a third generating unit at Little Long GS, Harmon GS & Kipling GS
- The incorporation of the new Smoky Falls GS and the retirement of the existing facility.
- The incorporation of both stages of the Prince Wind Farm - 189MW
- The incorporation of Yellow Falls GS - 20MW
- The installation of series capacitors in circuits X503E & X504E at Nobel SS to provide 50% compensation
- The addition of a 230kV-connected SVC at Porcupine TS with a rating of +300/-100MVAr
- The addition of a 115kV-connected SVC at Kirkland Lake TS with a rating of +200/-100MVAr

In addition, in order to respect minimum voltage requirements and to obtain an acceptable voltage profile, as well to minimise the reactive power output from the new SVCs and the generating units, it was found necessary to include the following shunt capacitor banks:

• Mississagi TS	96MVAr	*Σ 245MVAr* Identified Previously	*Total: Σ 952MVAr* Rated at 220kV
• Hanmer TS	149MVAr		
• Porcupine TS	250MVAr	Additional Requirements: *Σ 707MVAr*	
• Pinard TS	100MVAr		
• Little Long GS	100MVAr		
• Algoma TS	75MVAr		
• Essa TS	182MVAr		

This study has been adopted as the reference for all subsequent analysis

For this study the total generating capacity that was despatched in the north-east totalled **3804MW**.

This represents an increase of 653MW over the generation despatch that was assumed for the study whose results have been summarised in Diagram 3. This increase accounts for the incorporation of the following new generating facilities:

• The expansion of the Mattagami River plants and the retirement of the existing Smoky Falls GS	433MW	} Σ 653MW
• The incorporation of the Prince Wind Farm	200MW	
• The incorporation of Yellow Falls GS	20MW	

For this study the Flow-South transfer has increased to **2514MW** and this value has been adopted as the reference flow for the transient stability analysis that is discussed in Section 7 of this report.

Although a further 642MW of additional resources have been incorporated, the increase in the transfer across the Flow-South Interface shows an increase of only 515MW over that shown in Diagram 3. The difference is accounted for primarily through the increased transmission system losses within the north-east (from 281MW to 415MW)

Items of Note:

- Reactive Power Requirements

  The incorporation of the additional 642MW of generating capacity in the north-east is shown to increase the transmission system reactive power losses by almost 1000MVAr.

  While approximately 625MVAr of this (at an assumed voltage of 240kV) will be provided by the 525MVAr of additional shunt capacitor banks north of Sudbury (707MVAr minus the 182MVAr capacitor at Essa TS), the bulk of the remaining increase in the reactive power requirements will be supplied from the series capacitors at Nobel SS together with the additional shunt capacitor bank at Essa TS. These will result in a transfer of approximately 700MVAr into Hanmer TS via the two 500kV circuits: an increase of 320MVAr.

- Flows on the 230kV circuits H22D & L20D

  The projected flows on these circuits (1138A) will be only marginally within their continuous rating of 1140A for an ambient temperature of 30^{O}C and a wind speed of 4km/hr.

  Any further decrease in the combined load at the Spruce Falls mill; at Kapuskasing TS; and at Hearst TS beyond that which has been assumed in this study could therefore result in these circuits being overloaded.

  Although these circuits are not part of the existing NE LGR Scheme, they will need to be included in it once the new busbar is established at Little Long GS. This would then allow generation to be rejected following a single-circuit contingency involving either of these circuits so that the companion circuit is not overloaded.

- Flows through the 500/230kV auto-transformers at Pinard TS

  The combined transfer through these two auto-transformers is approximately 1300MVA, which with both auto-transformers in-service would be within their continuous ratings. However, an outage involving either auto-transformer would require the output from the generating facilities to be constrained so that the 10-day limited-time-rating of the companion unit is not exceeded.

  [Since the 500kV circuit-switcher associated with each auto-transformer at Pinard TS is not used for fault interrupting duty, a contingency that involves either auto-transformer would therefore result in both units being isolated due to the tripping of the 500kV circuit D501P. Consequently, the NE LGR Scheme is not required to recognise the loss of each individual auto-transformer.]

- Mississagi Flow-East

  With the GLP generating facilities operating at their maximum output and with the incorporation of the Prince Wind Farm, the flow across this Interface is expected to increase to approximately 1030MW. This would be well in excess of the present operating limit of 550MW.

  However, as mentioned earlier, the installation of the additional reactive support at both Mississagi TS and Algoma TS through a combination of SVCs and shunt capacitor banks would be expected to improve this limit by providing post-contingency voltage support at both Mississagi TS and Algoma TS following the loss of the Hanmer-Mississagi 230kV circuit or both Mississagi-Algoma 230kV circuits.

  For this transfer of 1030MW, the pre-contingency flows on the individual 230kV circuits between Mississagi TS and the Sudbury area are shown to remain within their continuous ratings. However, since any contingency involving one of these circuits would result in severe overloading of the remaining two circuits, a generation rejection Scheme would therefore need to be available if serious congestion of this Interface is to be avoided.

- Flows on the Hunta to Timmins 115kV circuits, H6T & H7T

  Although the flows on these circuits are shown to increase, primarily as a result of the incorporation of the Yellow Falls facility at Smooth Rock Falls, they still remain within the thermal ratings of these circuits at the Hunta terminals. However, the flow on the limiting section of circuit H6T into Timmins TS is shown to be approximately 50A over its continuous rating of 370A.

  It is therefore recommended that the section of circuits H6T & H7T between La Forest Junction and Timmins TS be uprated to at least 100^{o}C so that its rating is comparable to that for the section between Tower 5 and Tower 280.

  Furthermore, should it be decided to incorporate the Upper Mattagami Plants into the La Forest DS LV system it may be prudent to increase the rating of this section of circuits H6T & H7T beyond 100^{o}C to accommodate a possible power injection into the 115kV system at La Forest DS.

7. Transient Stability Analysis

Contingency Conditions

The Reference Load Flow Study has identified the Transfer Limits that would be required across each of the individual Interfaces to allow all of the planned, as well as all of the existing, resources to be accommodated without applying any restrictions under normal system conditions with all elements in-service.

Transient Stability Analysis was therefore performed for the following contingency conditions using these Interface Transfers, together with the appropriate margin, to determine whether the proposed facilities would allow these transfer levels to be achieved:

- A normally-cleared three-phase fault applied at the Hanmer terminal of the 500kV circuit X503E (or X504E)
- A normally-cleared three-phase fault applied at the Hanmer terminal of the 500kV circuit P502X
- A normally-cleared three-phase fault applied at the Porcupine terminal of the 500kV circuit D501P

For the D501P contingency, studies were also performed with the fault located at the Pinard terminal to confirm that applying a fault at the Porcupine terminal would represent the more severe condition.

Fault clearing and generation rejection times

The following times were used for each of the 500kV contingency conditions that were examined:

Fault clearance & G/R times for a contingency involving circuit X503E (or X504E):

•	Clearance of the fault at the Hanmer TS terminal		66msec
•	Clearance of the fault at the Essa TS terminal	+ 25msec	91msec
•	Rejection of the Moose River generating facilities	+ 89msec	180msec
•	Rejection of the NE non-utility generating facilities & the Prince wind farm	+ 50msec	230msec

Fault clearance & G/R times for a contingency involving circuit P502X:

For this contingency it was determined that cross-tripping of both the 500kV circuit D501P & the 230kV circuit L21S would be necessary

•	Clearance of the fault at the Hanmer TS terminal		66msec
•	Clearance of the fault at the Porcupine TS terminal & Cross-tripping of the Porcupine terminal of circuit D501P	+ 25msec	91msec
•	Cross-tripping of the 230kV breakers associated with circuit D501P at Pinard TS	+ 29msec	120msec
•	Cross-tripping of the 230kV circuit L21S at Kapuskasing TS & Rejection of the Moose River generating facilities	+ 60msec	180msec
•	Rejection of the NE non-utility generating facilities	+ 50msec	230msec

Fault clearance & G/R times for a contingency involving circuit D501P:

1.	*For a fault at the Porcupine terminal*		
•	Clearance of the fault at the Porcupine TS terminal		66msec
•	Clearance of the fault at the Pinard TS terminal (3-cycle breakers) & Cross-tripping of the 230kV circuit L21S at Kapuskasing TS	+ 42msec	108msec
2.	*For a fault at the Pinard terminal*		
•	Clearance of the fault at the Pinard TS terminal (3-cycle breakers) & Cross-tripping of the 230kV circuit L21S at Kapuskasing TS		83msec
•	Clearance of the fault at the Porcupine TS terminal	+ 8msec	91msec
•	Rejection of the Moose River generating facilities		180msec
•	Rejection of the NE non-utility generating facilities	+ 50msec	230msec

Provision of a 10% Margin on the Limiting Transfers

The IESO's Transmission Assessment Criteria require that -

'all stability limits should be shown to be stable if the most critical parameter is increased by 10%'.

In Diagram 5 the *reference* peak transfer across the Flow-South Interface, with all generating facilities in-service and with a maximum transfer of 325MW on the East-West Ties was shown to be 2514MW.

Consequently, to provide the required 10% margin, negative load was therefore added at the following busbars to increase this transfer to approximately 2765MW:

Location of Negative Load to Provide a Margin of 10% on the Flow-South Transfer			
•	Pinard 500kV busbar	100MW	To account for the additional transmission losses, the amount of negative load had to be increased by approximately 50MW
•	Porcupine 500kV busbar	100MW	
•	Mississagi 230kV busbar	100MW	

Sequence of Generation Rejection

For consistency between the study results, the following sequence was adopted for the order in which generation capacity is to be rejected in response to the various contingency conditions that were examined:

<table>
<tr><td colspan="6">Sequence used for Rejecting the Negative Loads & the Generating Units</td></tr>
<tr><td rowspan="3">1.</td><td colspan="2" rowspan="3">Trip the Negative Load</td><td>For an X503E or X504E contingency</td><td colspan="2">All three 100MW loads</td></tr>
<tr><td>For a P502X contingency</td><td colspan="2" rowspan="2">Only the 100MW loads at Pinard TS & Porcupine TS</td></tr>
<tr><td>For a D501P contingency</td></tr>
<tr><td>2.</td><td colspan="2">Trip the Prince 200MW Wind Farm</td><td>For an X503E (or X504E) contingency</td><td colspan="2">200MW</td></tr>
<tr><td>3.</td><td>Harmon GS</td><td>G1</td><td rowspan="8">For all three contingency conditions examined</td><td>79MW</td><td rowspan="6">Maximum Capacity Rejected: 426MW</td></tr>
<tr><td>4</td><td>Kipling GS</td><td>G1</td><td>79MW</td></tr>
<tr><td>5</td><td>Smoky Falls GS</td><td>G1</td><td>86MW</td></tr>
<tr><td>6</td><td>Little Long GS</td><td>G1</td><td>70MW</td></tr>
<tr><td>7</td><td>Otter Rapids GS</td><td>G1</td><td>47MW</td></tr>
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<tr><td>9 to 14</td><td colspan="2">Repeat sequence from 3 to 8 with the 2nd unit at each Mattagami River GS</td><td colspan="2">Maximum Capacity Rejected: 426MW</td></tr>
<tr><td>15 to 20</td><td colspan="2">Repeat sequence from 3 to 8 with the 3rd unit at each Mattagami River GS</td><td colspan="2">Maximum Capacity Rejected: 426MW</td></tr>
</table>

In addition, selected non-utility generation capacity was also rejected to respect the thermal limits on the 115kV transmission system.

For contingencies involving the 500kV system north of Sudbury (circuits P502X & D501P) only those negative loads at Pinard TS and Porcupine TS were rejected post-contingency. This would result in the negative load at Mississagi TS remaining connected following either of these contingency conditions.

Since the retention, post-contingency, of the negative load at Mississagi TS and the lack of any associated dynamic capability was considered to be too onerous, it was therefore decided to replace the negative load at Mississagi TS with a fictitious 100MW generating unit for the P502X & D501P contingencies.

Models Used for the SVC

For the load flow studies, each SVC was modelled as a generator with only a reactive power output equivalent to the rating proposed by Hydro One.

The generator representing the proposed SVC to be installed at Porcupine TS therefore had a range of -100MVAr to 300MVAr, while the range of the generator representing the Kirkland Lake SVC was set at -100MVAr to 200MVAr.

For the transient analysis, the CSVGN1 model shown in Diagram 6 was used to represent each SVC. Conservative parameters were selected for use in the model, on the expectation that the performance of the actual SVCs will be superior to that obtained in the analysis.

Once the supplier(s) of the SVCs have been selected, appropriate dynamic models that faithfully represent the behaviour of the SVCs are to be obtained to allow additional studies to be performed to confirm that the recommended settings will avoid excessive over-voltages at the associated busbars.

7.1 Preliminary Results for a P502X Contingency

Flow-East at Mississagi TS

The initial analysis indicated that once the Prince Wind Farm becomes fully operational and the peak transfer across the Mississagi Flow-East Interface could then exceed 1000MW, it would not be possible to maintain transient stability of the generating facilities associated with the East-West Tie following a contingency involving the 500kV circuit P502X.

The maximum transfer across the Mississagi Flow-East Interface for which stability could be maintained in response to a three-phase fault at the Hanmer terminal of the 500kV circuit P502X was found to be 980MW. After applying a margin of 10%, this would be equivalent to a transfer limit of **890MW;** 140MW less than the reference transfer of 1030MW. The corresponding flow on circuit P502X into Hanmer TS was 1670MW and the Flow-South transfer for this study was approximately 2700MW, or 2460MW after allowing for the 10% margin.

The upper portion of Diagram 7 shows the corresponding voltage at each of the critical busbars west of Sudbury in response to the P502X contingency. This shows the maximum voltage decline occurring at Marathon TS, with those at Algoma TS and Mississagi TS being the next most severe, respectively. It is also worth noting that the minimum voltages at Algoma TS and Mississagi TS occur approximately a half cycle earlier than that at Marathon TS.

The lower portion of Diagram 7 shows the post-contingency voltages for the condition with the transfer across the Mississagi Flow-East Interface increased by 25MW to 1002MW. This results in post-contingency instability.

The maximum voltage decline is shown to occur at Algoma TS, with that at Mississagi TS being the next most severe.

A study with a reduced transfer into Hanmer TS via circuit P502X was performed to determine whether the size of the flow into Hanmer TS was the cause of the instability. For this study the flow on circuit P502X into Hanmer TS was reduced to 1347MW, resulting in a Flow-South transfer of 2390MW.

The post-contingency voltages obtained from this study are shown in the lower half of Diagram 8. The results from the earlier study with a Flow-South into Hanmer TS of 1670MW have been reproduced in the upper half of this Diagram. [These are the same results that were shown in the lower half of Diagram 7, but with an expanded horizontal time scale to aid in the comparison of the two sets of results.]

Comparing the results for the two flow conditions shows that they are remarkably similar, with the only significant difference being a delay of approximately 0.1 seconds for the case with the lower flow into Hanmer TS, before the voltages hit their minimum values.

It has therefore been concluded that the low post-contingency voltages on the system west of Sudbury, together with the attendant instability of the generating units is primarily the result of the high transfers across the Mississagi East Interface rather than the level of the flow into Hanmer TS via the 500kV circuit P502X.

Diagram 9 shows the rotor angle response of the generating units to a P502X contingency for the same operating condition for which the post-contingency voltages are shown in the lower half of Diagram 8. The divergence between those generators associated with the system west of Algoma TS and those to the east of Algoma TS is clearly shown.

Installation of an additional SVC on the system west of Sudbury

Studies were performed with a single +300/-100MVAr SVC installed at various locations on the system west of Sudbury to examine the effect that it would have on the post-contingency performance of the system west of Sudbury.

Since Diagram 7 showed the minimum voltage occurring at Marathon TS, a study was performed with the SVC installed on the 230kV busbar at that location. The results, which are shown in Diagram 10, indicate that although the SVC would provide adequate post-contingency support for the voltage at Marathon TS, excessive voltage declines would still occur at both the Algoma and Mississagi 230kV busbars, leading to a loss of stability.

Diagram 11 shows the results with an SVC installed at Algoma TS (the upper half) or at Mississagi TS (the lower half). For both studies the post-contingency voltages are shown to recover and transient stability was maintained. Although either location for the SVC would be acceptable, the results show a marginally superior response, especially with respect to the voltage at Marathon TS, with the SVC located at Mississagi TS.

Furthermore, siting the SVC at Mississagi TS rather than Algoma TS would be preferable for a double-circuit contingency involving the Mississagi-to Algoma 230kV circuits since it would then remain available to provide the maximum post-contingency support to the flows across the remaining 230kV circuit, X74P, between Mississagi TS and Hanmer TS.

Diagram 12 shows the effect that an SVC at Algoma TS (or Mississagi TS) would have on reducing the accelerating power from all of the in-service generating units in north-western Ontario.

All of the subsequent analysis was therefore performed with a +300/-100MVAr SVC located at Mississagi TS.

7.2 Response to a P502X Contingency

With the system model modified to include an SVC at Mississagi TS, in addition to those that are to be installed at Porcupine TS and Kirkland Lake TS, a study was performed with the transfers on the principal interfaces set to represent those shown in the reference case (Diagram 5) with a further margin of 10%.

Interface	*Transfers in the Study with a 10% Margin*	*Equivalent Transfers with no margin*	*Reference Case Transfers from Diagram 5*
Mississagi Flow-East	1126MW	1024MW	1030MW
Flow into Hanmer on P502X	1672MW	1520MW	1503MW
Flow-South	2777MW	2525MW	2514MW

Diagram 13 shows the rotor angle response of the generating units to the P502X contingency and Diagram 14 shows the responses of the three SVCs together with their associated busbar voltages.

In Diagram 13 there is a clear distinction between the responses of those generating facilities associated with the 230kV system in the Sudbury area and those associated with the system north of Sudbury. With an SVC assumed at Mississagi TS, more rapid damping of the generating facilities in the former group is shown to occur, while for the latter group the oscillations are more pronounced, although adequately damped.

In Diagram 14, the SVCs are shown to result in stabilised voltages at their associated busbars within approximately 1.5 seconds of the fault being applied, although significant variations in the output of each of the SVCs is shown to continue for up to 7 seconds after the application of the fault.

Diagram 15 shows the same information as in Diagram 14 but on an expanded time scale. This has allowed the following switching activities to be identified and also provides a better view of the responses of the individual SVCs:

• At 0.2 seconds, the fault is applied	Time A
• After 66 milliseconds the fault is cleared at the local terminal: at Hanmer TS	Time B
• After a further 25msec (91msec), the fault is cleared at the remote terminal & circuit D501P is cross-tripped: at Porcupine TS	Time C
• After a further 29msec (120msec), circuit D501P is isolated at its remote terminal: at Pinard TS	Time D
• After 180msec following the application of the fault, the Moose River generating facilities are rejected	Time E
• After 230msec following the application of the fault, the NUG facilities in the north-east (excluding Northland Power-Kirkland Lake) are rejected	Time F
• After 250msec following the application of the fault, the Northland Power-Kirkland Lake facility is rejected	Time G
• After 1sec following the application of the fault, the shunt capacitor banks are tripped	Time H

The plot for the voltage at Porcupine TS shows that it momentarily increases to 3.1 pu immediately following isolation of the faulted circuit P502X at its remote terminal at Porcupine TS. During the subsequent 30 milliseconds, before the cross-tripping of circuit D501P at its Porcupine terminal can be completed, the principal path for the output of the generating units is through circuits D501P and P91G via Porcupine TS and the SVC at that location responds by producing its maximum reactive power output of 300MVAr.

An over-voltage of this magnitude would not be acceptable. However, since it is of very short duration it is assumed that it arises as a result of the particular model that was used to represent the SVC in the analysis.

Similarly, for the SVC at Kirkland Lake TS the voltage is shown to increase momentarily to a maximum of 1.6 pu in response to the same actions.

Consequently it will be necessary to ensure that the designs selected for the SVCs will not allow excessive over-voltages to occur in practice.

Load Flow Results

The load flow results following a P502X contingency, with the initial system conditions as shown in Diagram 5 (the Reference Case), have been summarised in Diagram 16. The principal responses that were initiated were as follows:

- Rejection of 1660MW of generating capacity in the north-east, north of Sudbury
- Cross-tripping of the 500kV circuit D501P and the 230kV circuits L21S, H22D & L20D
- Tripping of the following shunt capacitor banks:
    - 150MVAr at Porcupine TS
    - 150MVAr at Hanmer TS

The post-contingency transfers on the Interconnections, assuming no post-contingency contribution from the generating facilities in Ontario, are shown to total 1557MW. However, since the pre-contingency flow on the Interconnections was 50MW, the net change would be 1507MW. Although this would exceed the TLIC (Tie Line Inrush Current) limit of 1500MW, experience has shown that approximately 15% of any resource deficiency is automatically supplied from the Ontario generation facilities.

It is also worth noting that in order to respect the long-term emergency rating of circuit D3K between Kirkland Lake TS and Dymond TS, the entire Northland Power-Iroquois Falls facility had to be rejected. However, should it be feasible to increase the operating temperature of this line from its present 82^{O}C to 127^{O}C this would increase its LTE rating from 115MVA to 166MVA. This would allow half the Northland Power-Iroquois Falls facility to remain in-service post-contingency, while respecting the increased LTE rating of circuit D3K, as shown in Diagram 17.

With a total of 1594MW of generation capacity rejected, the combined transfers on the Interconnections would be 1515MW, representing a net change of 1465MW.

Diagrams 16 & 17 also show increased post-contingency transfers on the Manitoba and Minnesota Interfaces as follows:

Transfers on the Interconnections before & after a contingency involving the 500kV circuit P502X					
	Diagram No.	*Transfers on Interconnections*		*Voltage Angles*	
		With Manitoba	*With Minnesota*	*Kenora*	*Fort Frances*
Pre-contingency Transfers	5	282.0MW	-147.0MW	99.3^{o}	85.3^{o}
Post-contingency Transfers	16	319.4MW	-96.3MW	60.2^{o}	44.0^{o}
	Change	*+37.4MW*	*+50.7MW*	*-39.1°*	*-41.3°*
	17	318.6MW	-98MW	61.4^{o}	45.3^{o}
	Change	*+36.6MW*	*+49.0MW*	*-37.9°*	*-40.0°*

The angular change at Kenora TS is shown to exceed the -5^{o} setting of the $\Delta\theta$ element that supervises both the $\Delta P1$ and the $\Delta P2$ relays on the Ontario-Manitoba Interconnection and would therefore be sufficient to enable the relays. However, the change in the transfer across the Interconnections of approximately +50MW would not be sufficient to trigger operation of the $\Delta P1$ relay which is normally set at +300MW. It would however be marginally sufficient to trigger operation of the $\Delta P2$ relay if the minimum setting of +50MW were in effect. Since this setting is only deployed when one of the Kenora-Whiteshell circuits is out-of-service at the same time that transfers north across the US-Manitoba Interface exceed 900MW, it is not expected to be a concern. Should this very rare situation arise then the possible operation of the $\Delta P2$ relay could be avoided by temporarily limiting the transfers into Hanmer TS on circuit P502X. This would limit the amount of generation rejection that would need to be initiated in response to a P502X contingency and hence reduce the post-contingency flows that would occur over the Ontario-Manitoba Interconnections.

However, it should be noted that, subject to agreement with Manitoba Hydro, there is an expectation that these facilities will soon be disabled so that this will no longer be an issue.

Increase in Operating Reserve

The transmission system losses for the reference case shown in Diagram 5 total 1134MW, while those for the condition following a P502X contingency total 1034MW, as shown in Diagram 16; a difference of 100MW. Consequently the net effect on the system of rejecting 1660MW of generating capacity in response to a P502X contingency would be a resource deficiency of approximately 1560MW [1660MW - 100MW].

This would represent the single worst contingency for the system and would be expected to require an increase in the 30-minute operating reserve. This operating reserve is presently maintained at 1350MW to cover the 900MW deficiency resulting from the loss of one Darlington unit together with a further 450MW to cover half the loss in output from a second Darlington unit.

Frequency Response

Diagram 18 shows the frequency response at various busbars following a P502X contingency with subsequent cross-tripping of the 500kV circuit D501P.

This shows that the frequency at all of the monitored busbars would fall below the 59.3Hz threshold and for longer than the 300 milliseconds necessary for the first stage of the automatic low shedding to be triggered.

While the frequency at Hearst TS is also shown to fall below 58.8Hz, the second stage of load shedding is not expected to be initiated because the frequency is shown to be below this threshold for far less than the required 300 milliseconds.

It is therefore recommended that those loads that are part of the Under-Frequency Load-Shedding (UFLS) scheme in the area north of, and including, Timmins should only be associated with the Stage 2 portion of the Scheme so as to avoid any unintentional loss of load in response to a P502X contingency.

Relay Protection

Diagrams 19 & 20 show the apparent impedance loci for the 115kV circuits D3K and A8K, respectively, for a three-phase fault at the Hanmer terminal of the 500kV circuit P502X.

The apparent impedance loci for circuit D3K, as determined at the Kirkland Lake terminal and as reproduced in Diagram 19, is shown to enter the Zone 2 characteristic of the protective relaying. Since this would not provide the required margin of zero percent for relays having a time delay setting of less than or equal to 0.4 seconds, the existing protective relaying on this circuit would therefore not be acceptable.

For circuit A8K, the apparent impedance loci as shown in Diagram 20 would respect the margin criterion. Although not reproduced here, the results obtained for the companion 115kV circuit A9K were similar to those shown in Diagram 19.

7.3 Response to a D501P Contingency

Diagrams 21 & 22 show the rotor angle response of the generating units to contingencies involving the 500kV circuit D501P for the conditions with the fault located either at the Porcupine TS or at the Pinard TS terminal, respectively. The generators north and west of Sudbury have been grouped separately, with those north of Sudbury in the upper half of each Diagram.

The Diagrams show that the generating units north of Sudbury exhibit a marginally more pronounced swing for the condition with the fault located at the Porcupine terminal of circuit D501P. Furthermore, the effect is greatest on those units west of Timmins that are more remote from the moderating influence of the SVCs at Porcupine TS and Kirkland Lake TS.

They also show that the units remain stable with acceptable damping.

Load Flow Results

Diagram 23 shows the results from a load flow study that examined the post-contingency conditions following a D501P contingency and for which the principal responses that were initiated were as follows:

- Rejection of all of those generating facilities that are associated with the 230kV system connected to Pinard TS. The capacity of these facilities totals 1347MW.
- Cross-tripping of the 230kV circuits L21S, H22D & L20D
- Tripping of the following shunt capacitor banks:
    - 150MVAr at Porcupine TS
    - 300MVAr at Hanmer TS

As before, the initial system conditions for this study were as shown in Diagram 5 (the Reference Case).

With a lesser amount of generating capacity rejected, the study showed that the transfers on the Manitoba and Minnesota Interfaces would be reduced correspondingly:

	Diagram No.	*Transfers on the Interconnections*		*Voltage Angles*	
		With Manitoba	*With Minnesota*	*Kenora*	*Fort Frances*
Pre-contingency Transfers	5	282.0MW	-147.0MW	99.3^{o}	85.3^{o}
Post-contingency Transfers	23	315.2MW	-105.8MW	68.3^{o}	52.5^{o}
	Change	*+ 33.2MW*	*+ 41.2MW*	*- 31.0^{o}*	*- 32.8^{o}*

However, the high post-contingency flows on circuits H6T & H7T between Hunta SS and Timmins TS, and particularly over the final section into Timmins TS from Structure No. 284, are shown to exceed the LTE ratings of these circuits and could therefore require additional generation capacity to be rejected.

The post-contingency flows and the corresponding ratings are summarised below:

Post-contingency Flows following a 500kV contingency involving circuit D501P			
	115kV Circuits	*H6T*	*H7T*
Flow at Hunta SS		523A	485A
Long-Term Emergency Rating	*Limiting Section:* Structure 5 to 280 - op. temp: 99^{o}C	*520A*	*520A*
Flow at Timmins		**456A**	**408A**
Long-Term Emergency Rating	*Limiting Section:* Structure 284 to Timmins TS - op. temp: 70^{o}C	*370A*	*370A*

Since the entire line is equipped with 336.4kcmil conductors, uprating the section between Structure 284 to Timmins TS to raise its operating temperature to around 100^{o}C would increase the LTE rating of circuits H6T & H7T to more than 500A and this would be more than adequate to accommodate the project post-contingency flows.

Diagram 24 shows the response of the various SVCs together with their effect on the local voltages.

As expected in view of their close proximity to the fault location, the SVCs at Porcupine TS and Kirkland Lake TS are shown to provide a significant reactive power contribution during the post-fault period which helps stabilise the voltages in the area. However, it is also worth noting that even though the SVC at Mississagi TS is relatively remote from the faulted element, it continues to provide an important reactive power contribution.

Diagram 25 shows the SVC responses on an expanded time scale, with the following switching activities identified:

- At 0.2 seconds, the fault is applied — Time A
- After 66 milliseconds the fault is cleared at the local terminal: at Porcupine TS — Time B
- After a further 42msec (108msec), the fault is cleared at the remote terminal via the 230kV breakers at Pinard TS — Time C
- After 180msec following the application of the fault, the Moose River generating facilities are rejected — Time D
- After 230msec following the application of the fault, the NUG facilities in the north-east are rejected — Time E
- After 1sec following the application of the fault, the shunt capacitor banks are tripped — Time F

For this contingency condition the maximum voltages that were recorded were much more moderate, as shown below, reflecting the improved connectivity that is maintained post-contingency, between Porcupine TS and the rest of the system:

Porcupine TS:	Maximum voltage	1.14 pu
Kirkland Lake TS:	Maximum voltage	1.19 pu
Algoma TS:	Maximum voltage	1.20 pu

Relay Protection

Diagrams 26 & 27 show the apparent impedance loci for the 115kV circuits D3K and A4H, respectively, for a three-phase fault at the Porcupine terminal of the 500kV circuit D501P. In both instances, the loci remain well clear of the operating ranges defined by the relay characteristics and would therefore meet the margin requirements.

7.4 Response to an X503E (or X504E) Contingency

For a contingency involving the 500kV circuit X503E (or its companion circuit, X504E) with an initial transfer south across the Flow-South Interface of 2770MW (equivalent to 2518MW after allowing for the required margin of 10%), it was determined that 860MW of capacity, including the 300MW of negative load required to provide the margin, would need to be rejected to maintain post-contingency stability.

The rotor angle responses of selected generating units are shown in Diagram 28. Again, those units north of Sudbury have been grouped in the upper half of the Diagram while those west of Sudbury are shown in the lower half.

All of the units are shown to remain stable with adequately damped oscillations.

Diagram 29 shows the corresponding responses of the SVCs. As before, all three SVCs are shown to make considerable contributions, with the greatest contribution coming from the unit at Porcupine TS. Furthermore, the reactive contributions from the Porcupine SVC are shown to continue at a high level for a longer period than was the case for either a P502X contingency (Diagram 14) or a D501P contingency (Diagram 24). This is due in part to the greater amount of generation capacity that remains in-service in the area north of Timmins following an X503E (orX504E) contingency (approximately 1600MW after the rejection of 360MW of capacity).

Diagram 30 shows the SVC responses on an expanded time scale, with the following switching activities identified:

• At 0.2 seconds, the fault is applied	Time A
• After 66 milliseconds the fault is cleared at the local terminal: at Hanmer TS	Time B
• After a further 25msec (91msec), the fault is cleared at the remote terminal: at Essa TS	Time C
• After 180msec following the application of the fault, the Moose River generating facilities are rejected	Time D
• After 230msec following the application of the fault, the NUG facilities in the north-east are rejected	Time E
• After 1sec following the application of the fault, the shunt capacitor banks are tripped	Time F

The voltage plots in this Diagram show that for this contingency condition the maximum, transitory voltages that would be expected to occur would remain within an acceptable range:

Porcupine TS:	Maximum voltage	1.15 pu
Kirkland Lake TS:	Maximum voltage	1.23 pu
Algoma TS:	Maximum voltage	1.13 pu

Load Flow Results

The load flow results following an X503E (or X504E) contingency, with the initial system conditions as shown in Diagram 5 (the Reference Case), have been summarised in Diagram 31. The principal responses that were initiated were as follows:

- Rejection of 560MW of generating capacity in the north-east, north of Sudbury.
- Tripping of the following shunt capacitor banks:
    - 100MVAr at Porcupine TS
    - 100MVAr at Pinard TS
    - 100MVAr at Little Long GS

With this amount of generation rejection initiated, the post-contingency flow on the companion circuit X504E would be 2130A (1869MW/290MVAr at 512.7kV). This would exceed the continuous rating of 2080A for a section of circuit X504E and would require either of the following measures to be implemented:

- Uprate the critical section of circuit X504E that is equipped with quad 495kcmil conductors and presently has a sag temperature of 73^{o}C to a sag temperature of at least 76^{o}C.
- Increase the amount of generation capacity to be rejected during those periods when the transfers south across the Flow-South Interface are at their peak of approximately 2500MW by about 65MW to a total of 625MW.

The results with an additional 65MW 230kV-connected generating unit at Abitibi Canyon GS rejected in response to an X503E (or X504E) contingency are shown in Diagram 32.

With the additional generating capacity rejected, the flow on circuit X504E would then be reduced to 1977A which would be sufficient to respect its continuous rating of 2080A.

Frequency Response

Diagram 33 shows the frequency response at various busbars following an X503E (or X504E) contingency.

This shows that of the busbars that were monitored, the frequency recorded at both Hearst TS and Spruce Falls TS would fall below the 59.3Hz threshold. Furthermore, since the frequency at Hearst TS is shown to remain below the 59.5Hz threshold for approximately 300 milliseconds, this would therefore be expected to trigger the first stage of the automatic under-frequency load shedding.

This therefore supports the earlier recommendation that those loads that are part of the Under-Frequency Load-Shedding (UFLS) scheme in the area north of, and including, Timmins should only be associated with the Stage 2 portion of the Scheme so as to avoid any unintentional loss of load in response to either a P502X or an X503E (or X504E) contingency.

7.4.1 Power-Voltage Analysis

Diagram 34 shows the results of the PV-analysis for the post-contingency condition shown in Diagram 31 following the loss of circuit X503E (and the rejection of 560MW of generation capacity, together with the tripping of a 100MVAr capacitor bank at Porcupine TS, at Pinard TS and at Little Long SS).

As shown in Diagram 31, the post-contingency Flow-South transfer for this condition would be 2041MW.

Diagram 34 shows that for the voltages at Pinard TS, Porcupine TS and Hanmer TS, the respective voltage instability points (or knees) of their PV-curves would occur at a Flow-South transfer of approximately 2345MW. After applying a margin of 5%, the maximum Flow-South transfer that would be acceptable to ensure that the criterion for post-contingency voltage stability is respected would be approximately 2230MW. This would be well in excess of the projected post-contingency transfer of 2041MW (2145MW after allowing for the margin of 5%).

7.4.2 Delayed Generation Rejection

In all of the preceding analysis, the time interval that was assumed for completing the rejection of each individual generating unit via the NE Load & Generation Rejection Scheme was 180 milliseconds following the initial occurrence of the fault.

Since it has not been verified whether the NE Load & Generation Rejection Scheme is capable of achieving this response in practice, a study was therefore performed with the rejection time increased to 200 milliseconds to determine what effect, if any, a slower rejection time would have on the transient response.

Diagram 35 shows the rotor angle responses of selected generating units to a 3-phase fault at the Hanmer terminal of the 500kV circuit X503E (or X504E). The responses of those units north of Sudbury have been grouped in the upper half of the Diagram while those to the west of Sudbury are shown in the lower half.

All of the units are shown to remain stable with adequately damped oscillations.

If the responses in Diagram 28 (for a rejection time of 180msec) are compared with those in Diagram 35 (for a rejection time of 200msec), it is apparent that the increased G/R time has only a negligible effect of the magnitudes of the angular deviations for the respective generating units that were monitored. The delayed rejection time is, however, shown to affect the timing of the angular swings experienced by the respective generating units

To determine the magnitude of this delay, the time taken for the monitored unit at Little Long GS to reach its maximum angular deviation on its second swing has therefore been used as the reference:

Comparison of Generation Rejection Times: Rotor Angles at Little Long GS		
Rejection Time	*Diagram No.*	*Time taken by the Little Long Unit from fault occurrence*
180 milliseconds	28	1.90 seconds
200 milliseconds	35	2.20 seconds
	Difference	*0.30 seconds*

Consequently, the increase of 20 milliseconds in the rejection time is shown to result in a 300 millisecond delay in the angular deviation of the generating units.

Diagram 36 shows the corresponding responses of the SVCs for a rejection time of 200msec. As with the rotor angle responses, the responses of the individual SVCs are shown to be very similar in magnitude to those shown in Diagram 29, but with a similar delay before each SVC reaches is maximum output.

To determine the extent of this delay, the time taken for the SVC at Porcupine TS to reach its first ‘unconstrained’ peak output has been used as the reference:

Comparison of Generation Rejection Times: Porcupine SVC		
Rejection Time	*Diagram No.*	*Time taken by the Porcupine SVC from fault occurrence*
180 milliseconds	29	3.33 seconds
200 milliseconds	36	3.63 seconds
	Difference	*0.30 seconds*

These results therefore show an identical delay of 300msec in the associated response of the SVC at Porcupine TS to the 20msec increase in the generation rejection time.

The conclusion from this single study is that a rejection time of up to 200msec would not materially affect the post-contingency performance of the generating units nor adversely affect the transfer capability of the system. Whether this would remain valid for any additional delay in the generation rejection time beyond the 200msec that was examined would require further analysis. However, rather than make further assumptions, tests would need to be conducted by Hydro One to confirm the actual generation rejection times for the various components of the NE Load & Generation Rejection Scheme so that these could be used in all future analysis.

8.0 Performance of the System with no additional Shunt Capacitor Banks in-service

Hydro One's original proposal included only the SVCs at Porcupine TS and Kirkland Lake TS and the series capacitors at Nobel TS in the 500kV circuits between Hanmer TS and Essa TS. These additional facilities were intended to provide a sufficient increase in the transfer limit across the Flow-South Interface to accommodate only the increased capacity from the expanded generating facilities on the Mattagami River. Furthermore, the new 230kV busbar at Little Long GS as well as the additional capacitor banks that are required at Little Long GS and Pinard TS to compensate for the increased reactive power losses were considered to be part of this plan to expand the Mattagami River plants.

The analysis summarised in this section of the Report is therefore intended to quantify the improvement in the Flow-South transfer capability that would be provided by only those facilities in the original Hydro One proposal.

8.1 Analysis

8.1.1 Voltage Stability Analysis

PV-Analysis: With series capacitors at Nobel SS & SVCs at Porcupine TS and Kirkland Lake TS

The results from this study for the post-contingency condition following the loss of the 500kV circuit X 503E (or X504E) are shown in Diagram 37. The knee-points of the PV-curves are shown to occur at a Flow-South transfer of 2023MW. After applying a margin of 5%, the corresponding voltage stability limit for *post-contingency* transfers across the Flow-South Interface would therefore be **1921MW**.

Load Flow Analysis

Diagrams 38 & 39 show the results from the pre- and post-contingency load flow studies, respectively, for the condition that would result in a post-contingency transfer at the limiting value of 1921MW.

To achieve this post-contingency transfer of 1921MW, a pre-contingency Flow-South transfer of approximately 2000MW was found to be necessary to account for the increased post-contingency transmission losses and the reduced transfers across the Minnesota and Manitoba Interfaces. In Diagram 38, the pre-contingency transfers across the Flow-South and East-West Transfer East Interfaces are therefore shown to be 1996MW and 325MW, respectively.

For this study, in order to maintain a transfer across the Mississagi Flow-East Interface within the existing limit of 550MW (with no generation rejection initiated in response to a single-circuit contingency) while maintaining the East-West Transfer East flow at 325MW, it was necessary to assume the following facilities were out-of-service:

• Aubrey Falls GS	one generating unit	82MW
• Wells GS	one generating unit	120MW
• Lake Superior Power	the entire facility	120MW
• Prince I & II Wind Farms	the entire facilities	200MW
	Total Capacity	*522MW*

With these facilities out-of-service, the transfer across the Mississagi Flow-East Interface is shown to be reduced to 524MW.

With this transfer across the Mississagi Flow-East Interface, it was also found to be necessary to assume that the 20MW facility at Yellow Falls GS was out-of-service and that the net injection into the system from Abitibi Price facility at Iroquois Falls was reduced from 25MW to 10MW in order to achieve the required pre-contingency transfer of approximately 2000MW across the Flow-South Interface.

The results summarised in Diagram 38 for this particular loading condition show that an output of 231MVAr would be required from the SVC at Porcupine TS to maintain a voltage of 242kV on the Porcupine 230kV busbar.

In Diagram 39, with circuit X503E out-of-service and a post-contingency transfer across the Flow-South Interface of 1921MW, the SVC at Porcupine TS is shown to be at its maximum output of 300MVAr. Since it is no longer able to support the voltage on the 230kV busbar, it is shown to decline to 239kV, while that on the 500kV busbar at Porcupine TS falls to 505kV. However, the greatest decline is shown to occur at Hanmer TS, with the voltages falling to 498kV and 233kV on the 500kV and 230kV busbars, respectively. This is consistent with the results obtained from the PV-analysis, as shown in Diagram 37, with progressively lower voltages recorded at Pinard TS, Porcupine TS and at Hanmer TS.

This Diagram also shows a reduction of 17MW in the East-West Transfer East together with an increase of 63MW in the transmission system losses in the North-east from 292MW to 355MW: a net change of 80MW.

8.1.2 Transient Stability Analysis

A further series of transient stability studies were performed for the same system conditions with a transfer across the Mississagi Flow-East Interface of approximately 550MW, but with no additional shunt capacitor banks at Porcupine TS, Hanmer TS or Essa TS. For these studies that examined a contingency involving the 500kV circuit X503E (or X504E), the transfer across the Flow-South Interface was increased incrementally, with different amounts of generating capacity being rejected at the plants in the Moose River basin until stability could no longer be maintained. In addition, to provide the required margin of 10%, appropriate amounts of negative load were added at Pinard TS, Porcupine TS and Mississagi TS.

The limiting condition at which stability could be maintained corresponded to a Flow-South of 2427MW, which included 275MW of negative load. After deducting the negative load to account for the required margin, the maximum pre-contingency transfer across the Flow-South Interface for which stability could be maintained would therefore be 2152MW. For this transfer, 425MW of generating capacity would need to be automatically rejected in response to a contingency involving either of the 500kV circuits X503E or X504E.

Diagram 40 shows the rotor angle response of selected generating units to this contingency condition. The generating units north of Sudbury have been grouped in the upper half of the Diagram, while those west of Sudbury are shown in the lower half of the Diagram.

All of the units are shown to remain stable with adequately damped oscillations.

Diagram 41 shows the corresponding responses of the SVCs and their effect on the local voltages.

All three SVCs are shown to respond up to their maximum rated capability during the post-fault period as shown in the following Table:

SVC Outputs in response to an X503E (or X504E) contingency			
Location	*Initial Output prior to the Contingency*	*Final Output after 10 seconds*	*Maximum : Minimum Rated Output*
Porcupine TS	+300MVAr	+100MVAr	300MVAr : -100MVAr
Kirkland Lake TS	+20MVAr	-10MVAr	200MVAr : -40MVAr
Mississagi TS	-40MVAr	-50MVAr	300MVAr : -100MVAr

For this contingency condition, the maximum voltages that were recorded were as follows:

Porcupine TS:	Maximum 230kV voltage	1.09 pu
Kirkland Lake TS:	Maximum 115kV voltage	1.19 pu
Algoma TS:	Maximum 230kV voltage	1.14 pu

Transient Stability Analysis with no SVC at Mississagi TS

In earlier analysis it had been determined that in order to maintain post-contingency transient stability in response to a three-phase fault on circuit P502X at its Hanmer terminal, an SVC would be required at either Mississagi TS or Algoma TS once transfers across the Mississagi Flow-East Interface exceeded 890MW. Further details are given in Section 7.1 of this Report.

Consequently, for the conditions examined in the preceding Section, where the transfer across the Mississagi Flow-East Interface was only 550MW, an SVC at Mississagi TS would not be necessary.

The analysis was therefore repeated without an SVC at Mississagi TS.

The limiting Flow-South transfer for which stability could be maintained in response to a contingency involving the 500kV circuit X503E (or X504E) was found to remain at 2427MW which included 275MW of negative load. This reflects the minimal impact that the omission of an SVC at Mississagi TS would be expected to have on the initial acceleration of the generating units following the contingency.

However, to compensate for the loss of the post-contingency voltage support provided by the SVC at Mississagi TS, it was found that the amount of generating capacity that would need to be automatically rejected would need to be increased by 80MW to 505MW.

Diagram 42 shows the rotor angle response of selected generating units to this contingency condition. As before, the generating units north of Sudbury were grouped in the upper half of the Diagram, while those west of Sudbury were grouped in the lower half of the Diagram.

The responses shown in Diagram 42 are virtually identical to those shown in Diagram 40, with the principal difference being the lower rotor angles at which the generating units stabilise as a result in the increase in the amount of generation capacity rejected. All of the units remain stable with adequately damped oscillations.

Diagram 43 shows the corresponding responses of the SVCs and their effect on the local voltages. The maximum voltages that were recorded at the monitored busbars, together with their respective changes from those obtained from the preceding study with an SVC at Mississagi TS, were as follows:

Porcupine TS:	Maximum 230kV voltage	1.09 pu	-	no change
Kirkland Lake TS:	Maximum 115kV voltage	1.18 pu	-	a reduction of 0.01 pu (-1.2kV)
Algoma TS:	Maximum 230kV voltage	1.19 pu	-	an increase of 0.05 pu (+11kV)

Apart from this small increase in the post-contingency transient voltage at Algoma TS, the principal difference between Diagrams 41 and 43 is a reduction of approximately 25MVAr in the steady-state output of the SVC at Porcupine TS. This occurs because of the reduced reactive power losses as a result of the need to reject an additional 80MW of generating capacity in the Moose River basin to maintain transient stability.

Load Flow Results

Diagram 44 shows the pre-contingency load flow results for the condition with a Flow-South of 2152MW, representing the transient stability limit after allowing for the 10% margin. To achieve this transfer all the identified generating facilities, north of Sudbury, were assumed to be in-service, and generation capacity at Aubrey Falls GS and Wells GS was then added until the required Flow-South transfer was obtained. The additional generation capacity is shown to result in a transfer of 594MW across the Mississagi Flow-East Interface. Although this would exceed the present limit, it is expected that it would be within the revised limit once enhancements to the Mississagi SPS can be implemented to allow generation rejection to be initiated for single-circuit contingencies.

At this transfer level across the Flow-South Interface the output from the SVC at Porcupine TS is shown to be 276MVAr, which is close to its maximum rating of 300MVAr.

The results of the post-contingency load flow, following the loss of the 500kV circuit X503E (or X504E) and the rejection of 425MW of generating capacity at the Moose River plants, is shown in Diagram 45.

The post-contingency flow across the Flow-South Interface is shown as 1778MW which represents a reduction of 374MW from the pre-contingency value. This is less than the 425MW of generating capacity that has been rejected, primarily as a result of the reduced transmission losses due to lower amount of generating capacity in-service post-contingency (the losses in the North-east are shown to change from 327MW pre-contingency, to 283MW post-contingency).

Also, with the reduced amount of generating capacity in-service post-contingency following the initiation of the generation rejection, the output from the SVC at Porcupine TS is shown to fall to 180MVAr.

Since the post-contingency flow of 1778MW following the rejection of 425MW of generating capacity is less than the 1921MW transfer limit at which post-contingency voltage-stability can be maintained, these studies confirm that transient stability will therefore be more limiting than voltage stability.

8.2 Conclusions from the studies with no additional Shunt Capacitor Banks in-service

These studies demonstrate that the proposed series capacitors at Nobel SS together with the SVCs at Porcupine TS and Kirkland Lake TS would allow a maximum Flow-South of 2150MW to be achieved. This would be sufficient to accommodate all of the existing generating facilities north of Sudbury together with the planned expansion of the Mattagami River plants as well as the development of the 20MW Yellow Falls facility.

With all of the facilities north of Sudbury in-service, both existing and planned, the transfers across the Mississagi Flow-East Interface would therefore need to be limited to approximately 600MW.

9. Conclusions and Recommendations

A review of the *existing* resources in the north-east and north-west of the Province has indicated a potential transfer over the Flow-South Interface of approximately **2000MW**, as shown in Diagram 3. This assumes a transfer of approximately 840MW across the Mississagi Flow-East Interface. To achieve a transfer of this level, the existing Mississagi SPS would need to be expanded to allow generation rejection to be initiated in response to single-circuit contingencies and an SVC would need to be installed at Mississagi TS, together with an additional shunt capacitor bank at both Mississagi TS and Algoma TS, so that the present transfer limit for the Mississagi Flow-East Interface could be increased.

With the transfer limit for the Mississagi Flow-East Interface increased sufficiently to allow the output of the 200MW Prince Wind Farm to be accommodated, the potential transfer across the Flow-South Interface could therefore increase to **2150MW,** assuming a corresponding increase of approximately 50MW in the transmission losses.

The proposed 433MW expansion of the generating facilities at the Mattagami River Plants would then be expected to increase the potential Flow-South transfer to approximately **2500MW**, as shown in Diagram 5.

Local Enhancements to the Mississagi - Sudbury Interface

In order to increase the transfer limit on the Mississagi Flow-East Interface to approximately **1030MW** to accommodate all of the existing resources west of Mississagi TS, together with the maximum permissible transfers on the East-West Ties of 325MW, it has been determined in a companion study that the following facilities would need to be installed:

- an SVC rated at +300/-100MVAr at Mississagi TS, together with
- a 96MVAr (at 220kV) shunt capacitor bank at Mississagi TS, and
- a 75MVAr (at 220kV) shunt capacitor bank at Algoma TS

While all of the facilities listed above were included in the system model used for this Assessment, it should be noted that the approvals required for their connection to the IESO-controlled grid are to be the subject of a separate Assessment.

Local Enhancements to the Little Long - Pinard Interface

Similarly, in order to accommodate the proposed expansion of the Mattagami River Plants, the following facilities would need to be installed:

- a 230kV busbar at Little Long GS, together with
- a 100MVAr (at 220kV) shunt capacitor bank at Little Long GS
- a 100MVAr (at 220kV) shunt capacitor bank at Little Long GS

Again, although these facilities have been included in the system model used for this Assessment, the approvals required for their connection to the IESO-controlled grid are to be the subject of a further, separate Assessment.

9.1 Increase in the Flow-South Transfer Limit

i. With the series capacitors at Nobel SS together with the SVCs at Porcupine TS and Kirkland Lake TS

- ***together** with the local facilities identified for the expansion of the Mattagami River plants:*

  i.e. a new 230kV busbar at Little Long GS plus a 100MVAr shunt capacitor bank at both Little Long GS & Pinard TS

Subject to automatically rejecting 505MW of generating capacity in the Moose River basin immediately post-contingency, these facilities would allow the limit for pre-contingency transfers across the Flow-South Interface to be increased to ***2150MW.***

This would be adequate to accommodate all of the **existing & committed** generating facilities north of Sudbury together with an increase of **433MW** in the output from the expanded Mattagami River plants, and with a simultaneous transfer of approximately **600MW** across the Mississagi Flow-East Interface i.e. approximately 50MW above the present operating limit of 550MW for this Interface.

ii. With the series capacitors at Nobel SS together with the SVCs at Porcupine TS and Kirkland Lake TS

- ***together** with the local facilities identified for the expansion of the Mattagami River plants:*

  i.e. a new 230kV busbar at Little Long GS plus a 100MVAr shunt capacitor bank at both Little Long GS & Pinard TS

- ***together** with the local facilities identified for enhancing the transfer capability across the Mississagi Flow-East Interface:*

  i.e. a +300/-100MVAr SVC at Mississagi TS plus a 100MVAr shunt capacitor bank at both Mississagi TS & Algoma TS

- ***together** with additional 230kV shunt capacitor banks at the following locations:*

• Porcupine TS	2 x 125MVAr shunt capacitor banks	rated at 220kV
• Hanmer TS	a 2nd 149MVAr shunt capacitor bank	
• Essa TS	a 2nd 182MVAr shunt capacitor bank	

These facilities would allow the limit for transfers across the Flow-South Interface to be increased to ***2500MW.***

This would be adequate to accommodate all of the **existing & committed** generating facilities both north and west of Sudbury together with the increased output from the expanded Mattagami River plants, and with a simultaneous transfer of approximately **1030MW** across the Mississagi Flow-East Interface.

This increase in the transfer capability across the Mississagi Flow-East Interface would be adequate to accommodate all of the **existing** generating facilities between Wawa TS and the Sudbury area, including the Prince I & II Projects, together with a transfer of **325MW** across the East-West Transfer East Interface.

9.2 Increased Transfers into Timmins & Sudbury

Flow-South Into Timmins

The proposed expansion of the Mattagami River plants would result in a maximum transfer across this Interface of approximately **1300MW.** (see Diagram 5)

With transfers at this level, generation rejection totalling approximately 1300MW (see Diagram 23) would be required in response to a contingency involving the 500kV circuit D501P. In addition, the 230kV circuits H22D, L20D & L21S would need to be cross-tripped. One of the shunt capacitor banks at Porcupine TS together with both capacitor banks at Hanmer TS would also need to be tripped: the capacitor banks at Little Long GS and Pinard TS would be automatically disconnected with the cross-tripping of the 230kV circuits.

Flow-South Into Sudbury

The maximum transfer across this Interface would be approximately **1600MW** following the proposed expansion of the Mattagami River plants.

With transfers at this level, generation rejection totalling approximately 1600MW (see Diagram 17), together with the cross-tripping of the 500kV circuit D501P and the 230kV circuits H22D, L20D & L21S would be required in response to a contingency involving the 500kV circuit P502X. In addition, one of the shunt capacitor banks at Porcupine TS together with one of the capacitor banks at Hanmer TS would need to be tripped.

The rejection of 1600MW, which after taking account of the associated change in the transmission losses would translate into a net resource deficiency of approximately 1500MW (as shown in Diagram 17), would then represent the single largest contingency condition on the IESO-controlled grid and would require a corresponding increase in both the 10-minute and 30-minute operating reserves.

Potential Effect on NPCC Utilities

i. For Contingencies involving either of the 500kV circuits P502X & D501P

None of the analysis that has been performed for this Assessment has indicated that the increased levels of generation rejection that are expected to be necessary in response to either a P502X or a D501P contingency would have an adverse effect on either the IESO-controlled grid or on the systems of our neighbouring utilities.

Consequently, for contingencies involving either of the 500kV circuits P502X or D501P, it is expected that the North-east Load & Generation Scheme will continue to be classified as a Type III SPS by NPCC (the North-east Power Co-ordinating Council).

The continued application of generation rejection in response to a first contingency would therefore not violate the IESO's Ontario Resource & Transmission Criteria that prohibit the reliance on a Type I Special Protection System, when all transmission elements are in-services, except during the transitional period while new transmission reinforcements are being brought into service.

ii. For contingencies involving either of the 500kV circuits X503E or X504E

Without the additional shunt capacitor banks at Porcupine TS, Hanmer TS and Essa TS, the maximum Flow-South transfer that could be achieved while maintaining a transient stability margin of 10% would be 2150MW. This would, however, require the automatic rejection of 425MW of generating capacity.

With the additional shunt capacitor banks at Porcupine TS, Hanmer TS and Essa TS, the maximum Flow-South transfer that could be achieved would increase to 2518MW. The amount of generating capacity that would need to be automatically rejected would also increase to 560MW.

For Flow-South transfers at either of these levels, a failure of the SPS to initiate generation rejection would be expected to result in transient and/or voltage instability with a potential risk that the system would separate across the North-South Interface. This would result in a resource deficiency in southern Ontario of either 2150MW (less the net change in the transmission losses) or 2518MW (less the net change in the transmission losses).

A resource deficiency of either of these magnitudes would be expected to have an adverse effect on the systems of our neighbouring utilities and could therefore result in that part of the SPS that responds to an X503E or X504E contingency being classified as a Type I SPS by NPCC.

In anticipation of this future classification, it is therefore recommended that those facilities associated with an X503E or X504E contingency be fully duplicated to meet the NPCC requirements for a Type I SPS.

Reliance on a Type I SPS

In Section 2.3.4 of the OPA's Discussion Paper No.5: Transmission - for the Integrated Power Supply Plan, reference is made to the development of additional transmission facilities between Barrie and the GTA to enhance the Flow-South capability, with a lead-time of between five and seven years. Since continued reliance on a Type I Special Protection System, when all transmission elements are in-services, is permitted during the transitional period while new transmission reinforcements are being brought into service, there would therefore be no violation of the IESO's Ontario Resource & Transmission Criteria.

9.3 IESO-Requirements & Recommendations

The analysis performed for this Assessment has also identified the following requirements:

- The frequency responses for both a P502X and a D501P contingency have shown that the frequency at selected busbars is expected to fall below the 59.3Hz threshold for longer than the 300 milliseconds that would trigger load rejection via the first stage of the Under-Frequency Load-Shedding (UFLS) Scheme. The IESO therefore requires that all of the loads in the area north of, and including Timmins should only be associated with the Stage 2 portion of the UFLS Scheme.

- The apparent impedance loci for the 115kV circuit D3K in response to a P502X contingency is shown to enter the Zone 2 characteristic of the protective relaying. Since this would not provide the required margin, the IESO requires the protective relaying on this circuit to be reviewed, and if necessary modified to ensure that this circuit is not tripped for external faults.

  Since each of the following circuits are considered to be critical to the post-contingency performance of the system north of Sudbury, it is also recommended that the protective relaying on these circuits be reviewed, even though the analysis has indicated that the required margin would be met:

Circuits	*Terminal Stations*	*Contingency Condition*
A4H & A5H	Hunta SS to Ansonville TS	D501P & P502X (with D501P cross-tripped)
A8K & A9K	Ansonville TS to Kirkland Lake TS	P502X (with & without D501P cross-tripped)
D3K	Kirkland Lake TS to Dymond TS	P502X (with & without D501P cross-tripped)
W71D	Dymond TS to Widdifield SS	P502X (with & without D501P cross-tripped)

- Once the supplier(s) of the SVCs have been selected, appropriate dynamic models are to be obtained that faithfully represent the behaviour of the devices so that additional studies can be performed to confirm that the recommended settings will avoid excessive over-voltages at the associated busbars.

- Modifications to the NE Load & Generation Rejection Scheme are required to provide the required cross-tripping features as detailed below, as well as the ability to arm the following shunt capacitor banks for automatic tripping:

Circuits to be separately Cross-tripped	*Contingency Conditions*
500kV circuit D501P	P502X
230kV circuit H22D	P502X & D501P
230kV circuit L20D	P502X & D501P
230kV circuit L21S	P502X & D501P
Shunt Capacitor Banks to be tripped	
Little Long GS	P502X, D501P, X503E & X504E
Pinard TS	P502X, D501P, X503E & X504E
1st & 2nd cap banks individually at Porcupine TS	P502X, D501P, X503E & X504E
1st & 2nd cap banks individually at Hanmer TS	P502X, D501P, X503E & X504E

  In addition, the NE Load & Generation Rejection Scheme is to have the capability of initiating the rejection of each stage of the Prince Wind Farm development individually in response to a 500kV contingency involving either circuit X503E or circuit X504E.

  These new facilities, together with those existing facilities that are associated with an X503E or X504E contingency, are required to be fully duplicated to meet the requirements for possible future classification of part of the NE Load & Generation Rejection Scheme as a Type I SPS.

- The IESO requires tests to be conducted on the NE Load & Generation Rejection Scheme to determine definitive time delays for the rejection of the various generating units covered by the Scheme for each of the contingency conditions that are respected.

  Should the time delays obtained from these tests vary significantly from those assumed in this assessment then it may be necessary to perform additional analysis to determine the effect that they would have on the post-contingency performance of the system.

- Uprate the 500kV circuits E510V & E511V between Essa TS and Claireville TS.

- Uprate the section of the 115kV circuits H6T & H7T between La Forest Junction and Timmins TS.

10. Customer Impact Assessment

Once a formal decision is made to proceed with the installation of the series capacitors at Nobel TS, together with the SVCs at Porcupine TS and Kirkland Lake TS, Hydro One Networks Inc. is proposing to conduct a Customer Impact Assessment for this Project to determine whether the proposed facilities could have a material adverse effect on their customers.

Should any major issues be identified through the CIA process then these will be addressed through an Addendum to this Report.

11. Notification of Approval of the Connection Proposal

Subject to the completion of the Customer Impact Assessment and the satisfactory resolution of any issues that it may raise, as well meeting all of the requirements identified in Section 8.2, the IESO has concluded that the following work will have no materially adverse effect on the IESO-controlled grid:

- the installation of series capacitors at Nobel TS in each of the Hanmer-to-Essa TS 500kV circuits to provide 50% compensation for the line reactance.
- the installation of a 230kV-connected SVC at Porcupine TS, rated at +300/-100MVAr
- the installation of a 115kV-connected SVC at Kirkland Lake TS, rated at +200/-100MVAr

It is therefore recommended that a Notification of Conditional Approval to Connect be issued for this work.

This approval also covers the following work:

- The uprating of the 500kV circuits E510V & E511V between Essa TS and Claireville TS
- The uprating of the section of the 115kV circuits H6T & H7T between La Forest Junction and Timmins TS
- The modification of the NE Load & Generation Rejection Scheme, including the duplication of those facilities associated with an X503E or X504E contingency to meet the requirements for possible classification as a Type I SPS.
- The modification of the Under-Frequency Load-Shedding Scheme in the north-east

Approval for those facilities directly associated with the following are expected to be the subject of separate Assessments, and are therefore not included in this Notification of Approval:

- The enhancement of the Mississagi Flow-East Interface
- The incorporation of the additional generating facilities at the expanded Mattagami River plants, and
- The installation of additional shunt capacitor banks to increase the Flow-South transfer capability from 2150MW to 2500MW.

APPENDIX A Line Ratings

500kV Line Ratings: North-East			*Ratings at 30^{o}C Ambient: 4km/hr wind: MVA at 520kV*						
Circuit	*Conductor (Limiting Section)*	*Sag Temp*	*Continuous at 93^{o}C or Sag Temperature, if lower*		*Long-Term 'Emergency' at 127^{o}C or Sag Temperature, if lower*		*15-min LTR at Sag Temperature*		
D501P: Pinard TS to Porcupine TS									
Pinard TS to Structure 1 ***(East)***	Quad 583.2 18/7	71^{o}C	2210A	1990MVA	2210A	1990MVA	2210A	1990MVA	*Pre-load of 2210A*
Structure 1 Dead-end Loops ***(E)***	Twin 795.0 26/7	127^{o}C	1780A	1603MVA	2280A	2054MVA	2510A	2261MVA	*Pre-load of 1780A*
Pinard TS to Structure 1 ***(West)***	Quad 585.0 26/7	127^{o}C	2950A	2657MVA	3750A	3377MVA	4020A	3621MVA	*Pre-load of 2950A*
Structure 1 Dead-end Loops ***(W)***	Twin 3640 91/0	127^{o}C	4070A	3666MVA	5330A	4800MVA	6940A	6251MVA	*Pre-load of 4070A*
Structure 1 ***(East)*** to ***(West)***	Twin 795.0 26/7	127^{o}C	1780A	1603MVA	2280A	2054MVA	2510A	2261MVA	*Pre-load of 1780A*
Str 1 ***(East)*** to Porcupine TS	Quad 583.2 18/7	71^{o}C	2210A	1990MVA	2210A	1990MVA	2210A	1990MVA	*Pre-load of 2210A*
P502X: Porcupine TS to Hanmer TS									
Porcupine TS to Hanmer TS	Quad 583.2 18/7	71^{o}C	2210A	1990MVA	2210A	1990MVA	2210A	1990MVA	*Pre-load of 2210A*
X503E: Hanmer TS to Essa TS									
Hanmer TS to Junction Point	Quad 495.0 22/7	79^{o}C	2270A	2045MVA	2270A	2045MVA	2270A	2045MVA	*Pre-load of 2270A*
Junction Point to Junction Point	Quad 520.2 18/7	79^{o}C	2330A	2099MVA	2330A	2099MVA	2330A	2099MVA	*Pre-load of 2330A*
Junction Point to Essa TS	Quad 495.0 22/7	79^{o}C	2270A	2045MVA	2270A	2045MVA	2270A	2045MVA	*Pre-load of 2270A*
X504E: Hanmer TS to Essa TS									
Hanmer TS to Junction Point	Quad 520.2 18/7	73^{o}C	2130A	1918MVA	2130A	1918MVA	2130A	1918MVA	*Pre-load of 2130A*
Junction Point to Junction Point	Quad 495.0 22/7	73^{o}C	2080A	1873MVA	2080A	1873MVA	2080A	1873MVA	*Pre-load of 2080A*
Junction Point to Junction Point	Quad 495.0 22/7	76^{o}C	2180A	1963MVA	2180A	1963MVA	2180A	1963MVA	*Pre-load of 2180A*
Junction Point to Essa TS	Quad 468.3 26/7	78^{o}C	2180A	1963MVA	2180A	1963MVA	2180A	1963MVA	*Pre-load of 2180A*

APPENDIX A (Continued) Line Ratings

230kV Line Ratings: North-East			*Ratings at 30°C Ambient: 4km/hr wind: MVA at 240kV*						
Circuit	*Conductor (Limiting Section)*	*Sag Temp*	*Continuous at 93°C or Sag Temperature, if lower*		*Long-Term 'Emergency' at 127°C or Sag Temperature, if lower*		*15-min LTR at Sag Temperature*		
H22D & L20D: Pinard TS to Little Long GS									
Pinard TS to Little Long GS	1277.5kcmil 42/7	93°C/127°C	1140A	474MVA	1470A	611MVA	1680A	698MVA	*Pre-load of 1140A*

115kV Line Ratings: North-East				*Ratings at 30°C Ambient: 4km/hr wind: MVA at 121kV*						
Circuit		*Conductor (Limiting Section)*	*Sag Temp*	*Continuous at 93°C or Sag Temperature, if lower*		*Long-Term 'Emergency' at 127°C or Sag Temperature, if lower*		*15-min LTR at Sag Temperature*		
D3K: Dymond TS to Kirkland Lake TS										
Dymond TS to Kirkland Lake TS		477kcmil 26/7	82°C	550A	115MVA	550A	115MVA	550A	115MVA	*Pre-load of 550A*
H9K: Hunta SS to Kapuskasing TS										
Kapuskasing TS to O'Brien Jct		795kcmil 26/7	110°C	850A	178MVA	980A	205MVA	1050A	220MVA	*Pre-load of 850A*
O'Brien Jct to Structure 585		336.4kcmil 26/7	150°C	490A	103MVA	630A	132MVA	740A	155MVA	*Pre-load of 490A*
Structure 585 to Carmichael Jct		211.6kcmil 6/1	71°C	280A	59MVA	280A	59MVA	280A	59MVA	*Pre-load of 280A*
Carmichael Jct to Fauquier Jct			144°C	370A	78MVA	460A	96MVA	510A	107MVA	*Pre-load of 370A*
Fauquier Jct to Malette Jct			88°C	350A	73MVA	350A	73MVA	350A	73MVA	*Pre-load of 350A*
Malette Jct to Structure 127			150°C	370A	78MVA	460A	96MVA	530A	111MVA	*Pre-load of 370A*
Str 127 to Hunta Jct	D/C Line Parallelled		66°C	260A	54MVA	260A	54MVA	260A	54MVA	*Pre-load of 260A*
Str 127 to Str 116			68°C	270A	57MVA	270A	57MVA	270A	57MVA	*Pre-load of 270A*
Str 116 to Hunta Jct			68°C	270A	57MVA	270A	57MVA	270A	57MVA	*Pre-load of 270A*
Hunta Jct to Hunta SS		795kcmil 26/7	150°C	850A	178MVA	1090A	228MVA	1400A	293MVA	*Pre-load of 850A*

APPENDIX A (Continued) Line Ratings									
115kV Line Ratings: North-East			*Ratings at 30^{o}C Ambient: 4km/hr wind: MVA at 121kV*						
Circuit	*Conductor (Limiting Section)*	*Sag Temp*	*Continuous at 93^{o}C or Sag Temperature, if lower*		*Long-Term 'Emergency' at 127^{o}C or Sag Temperature, if lower*		*15-min LTR at Sag Temperature*		
H6T & H7T:Hunta SS to Timmins TS									
Hunta SS to Tower No. 5	336.4kcmil 30/7	150^{o}C	500A	104MVA	630A	132MVA	750A	157MVA	*Pre-load of 500A*
Tower No. 5 to Tower No. 280		99^{o}C	500A	104MVA	520A	109MVA	530A	111MVA	*Pre-load of 500A*
Tower No. 280 to Tower No. 284	336.4kcmil 26/7	150^{o}C	500A	104MVA	630A	132MVA	750A	157MVA	*Pre-load of 500A*
Tower No. 284 to Timmins TS	336.4kcmil 30/7	70^{o}C	370A	78MVA	370A	78MVA	370A	78MVA	*Pre-load of 370A*
A4H: Ansonville TS to Hunta SS									
Ansonville TS to Hunta SS	203.2kcmil 16/19	60^{o}C	260A	54MVA	260A	54MVA	260A	54MVA	*Pre-load of 260A*
A5H: Ansonville TS to Hunta SS									
Ansonville TS to Str 210	795kcmil 26/7	150^{o}C	850A	178MVA	1090A	228MVA	1400A	293MVA	*Pre-load of 850A*
Str 210 to Str 206	468.3kcmil 26/7	150^{o}C	610A	128MVA	780A	163MVA	940A	197MVA	*Pre-load of 610A*
Str 206 to Str 200	336.4kcmil 26/7	150^{o}C	500A	104MVA	630A	132MVA	750A	157MVA	*Pre-load of 500A*
Str 200 to Str 8									
Str 8 to Str 4	203.2kcmil 16/19	150^{o}C	380A	88MVA	490A	103MVA	580A	122MVA	*Pre-load of 380A*
Str 4 to Iroquois Falls Jct	336.4kcmil 26/7	130^{o}C	500A	104MVA	630A	132MVA	750A	157MVA	*Pre-load of 500A*
Iroquois Fall Jct to Str 186	336.4kcmil 26/7	150^{o}C	500A	104MVA	630A	132MVA	750A	157MVA	*Pre-load of 500A*
Str 186 to Str 123	500kcmil 30/7	73^{o}C	500A	104MVA	500A	104MVA	500A	104MVA	*Pre-load of 500A*
Str 123 to Str 51	500kcmil 30/7	76^{o}C	520A	109MVA	520A	109MVA	520A	109MVA	*Pre-load of 520A*
Str 51 to Fournier Jct	477kcmil 26/7	150^{o}C	620A	130MVA	790A	166MVA	960A	201MVA	*Pre-load of 620A*
Fournier Jct to Str 50									
Str 50 to Hunta SS	500kcmil 30/7	66^{o}C	440A	92MVA	440A	92MVA	440A	92MVA	*Pre-load of 440A*

APPENDIX A (Continued) *Line Ratings*									
115kV Line Ratings: North-East			*Ratings at 30^{o}C Ambient: 4km/hr wind: MVA at 121kV*						
Circuit	*Conductor (Limiting Section)*	*Sag Temp*	*Continuous at 93^{o}C or Sag Temperature, if lower*		*Long-Term 'Emergency' at 127^{o}C or Sag Temperature, if lower*		*15-min LTR at Sag Temperature*		
A8K: Ansonville TS to Kirkland Lake TS									
Ansonville TS to Tower No. 271	468.3kcmil 26/7	60^{o}C	420A	88MVA	420A	88MVA	420A	88MVA	*Pre-load of 420A*
Tower No. 271 to Junction Point	167.8kcmil 6/1	60^{o}C	220A	46MVA	220A	46MVA	220A	46MVA	*Pre-load of 220A*
Junction Point to Tower No. 408	211.6kcmil 6/1	60^{o}C	260A	54MVA	260A	54MVA	260A	54MVA	*Pre-load of 260A*
Tower No. 408 to Tower No. 648	133.2kcmil 7/0 Cu	60^{o}C	250A	52MVA	250A	52MVA	250A	52MVA	*Pre-load of 250A*
Tower No. 648 to Tower No. 652	203.2kcmil 16/19	150^{o}C	380A	88MVA	490A	103MVA	580A	122MVA	*Pre-load of 380A*
Tower 652 to Kirkland Lake SS	167.8kcmil 6/1	60^{o}C	220A	46MVA	220A	46MVA	220A	46MVA	*Pre-load of 220A*
A9K: Ansonville TS to Kirkland Lake TS									
Ansonville TS to Junction Point	795kcmil 26/7	127^{o}C	850A	178MVA	1090A	228MVA	1210A	254MVA	*Pre-load of 850A*
Junction Point to Junction Point	468.3kcmil 26/7	60^{o}C	420A	88MVA	420A	88MVA	420A	88MVA	*Pre-load of 420A*
Junction Point to Junction Point	336.4kcmil 26/7	60^{o}C	340A	71MVA	340A	71MVA	340A	71MVA	*Pre-load of 340A*
Jct Pt to Monteith Jct to Jct Pt	167.8kcmil 6/1	82^{o}C	280A	59MVA	280A	59MVA	280A	59MVA	*Pre-load of 280A*
Junction Point to Junction Point	477kcmil 26/7	82^{o}C	550A	115MVA	550A	115MVA	550A	115MVA	*Pre-load of 550A*
Junction Point to Junction Point	167.8kcmil 6/1	82^{o}C	280A	59MVA	280A	59MVA	280A	59MVA	*Pre-load of 280A*
Junction Point to Junction Point	211.6kcmil 6/1	82^{o}C	330A	69MVA	330A	69MVA	330A	69MVA	*Pre-load of 330A*
Junction Point to Junction Point	167.8kcmil 6/1	82^{o}C	280A	59MVA	280A	59MVA	280A	59MVA	*Pre-load of 280A*
Junction Point to Ramore Jct	167.8kcmil 7/0 Cu	82^{o}C	360A	75MVA	360A	75MVA	360A	75MVA	*Pre-load of 360A*
Ramore Jct to Ramore TS	167.8kcmil 7/0 Cu	150^{o}C	400A	84MVA	500A	105MVA	570A	119MVA	*Pre-load of 400A*
Ramore TS to Structure 316	167.8kcmil 7/0 Cu	150^{o}C	400A	84MVA	500A	105MVA	570A	119MVA	*Pre-load of 400A*
Structure 316 to Kirkland Lake TS	167.8kcmil 7/0 Cu	60^{o}C	290A	61MVA	290A	61MVA	290A	61MVA	*Pre-load of 290A*

APPENDIX A (Continued) Line Ratings									
115kV Line Ratings: North-East			*Ratings at 30^{o}C Ambient: 4km/hr wind: MVA at 121kV*						
Circuit	*Conductor (Limiting Section)*	*Sag Temp*	*Continuous at 93^{o}C or Sag Temperature, if lower*		*Long-Term 'Emergency' at 127^{o}C or Sag Temperature, if lower*		*15-min LTR at Sag Temperature*		
D2L: Dymond TS to Crystal Falls GS									
Dymond TS to Structure 84	477kcmil 26/7	60^{o}C	420A	88MVA	420A	88MVA	420A	88MVA	*Pre-load of 420A*
Structure 84 to Structure 85	795kcmil 26/7	150^{o}C	850A	178MVA	1090A	228MVA	1400A	293MVA	*Pre-load of 850A*
Structure 85 to Structure 261	477kcmil 26/7	60^{o}C	420A	88MVA	420A	88MVA	420A	88MVA	*Pre-load of 420A*
Structure 261 to Structure 95	167.8kcmil 6/1 **TWIN**	60^{o}C	450A	94MVA	450A	94MVA	450A	94MVA	*Pre-load of 450A*
Structure 95 ***(N)*** to Cassels SS	795kcmil 26/7	150^{o}C	850A	178MVA	1090A	228MVA	1400A	293MVA	*Pre-load of 850A*
Cassels SS to Structure 95 ***(S)***	795kcmil 26/7	150^{o}C	850A	178MVA	1090A	228MVA	1400A	293MVA	*Pre-load of 850A*
Structure 95 ***(S)*** to Str 105 ***(N)***	167.8kcmil 6/1 **TWIN**	60^{o}C	450A	94MVA	450A	94MVA	450A	94MVA	*Pre-load of 450A*
Str 105 ***(N)*** to Herridge Lake DS	477kcmil 26/7	150^{o}C	620A	130MVA	790A	166MVA	960A	201MVA	*Pre-load of 620A*
Herridge Lake DS to Str 105 ***(S)***	477kcmil 26/7	150^{o}C	620A	130MVA	790A	166MVA	960A	201MVA	*Pre-load of 620A*
Str 105 ***(S)*** to Str 263 to Str 409	167.8kcmil 6/1 **TWIN**	60^{o}C	450A	94MVA	450A	94MVA	450A	94MVA	*Pre-load of 450A*
Structure 409 to Crystal Falls SS	477kcmil 26/7	150^{o}C	620A	130MVA	790A	166MVA	960A	201MVA	*Pre-load of 620A*

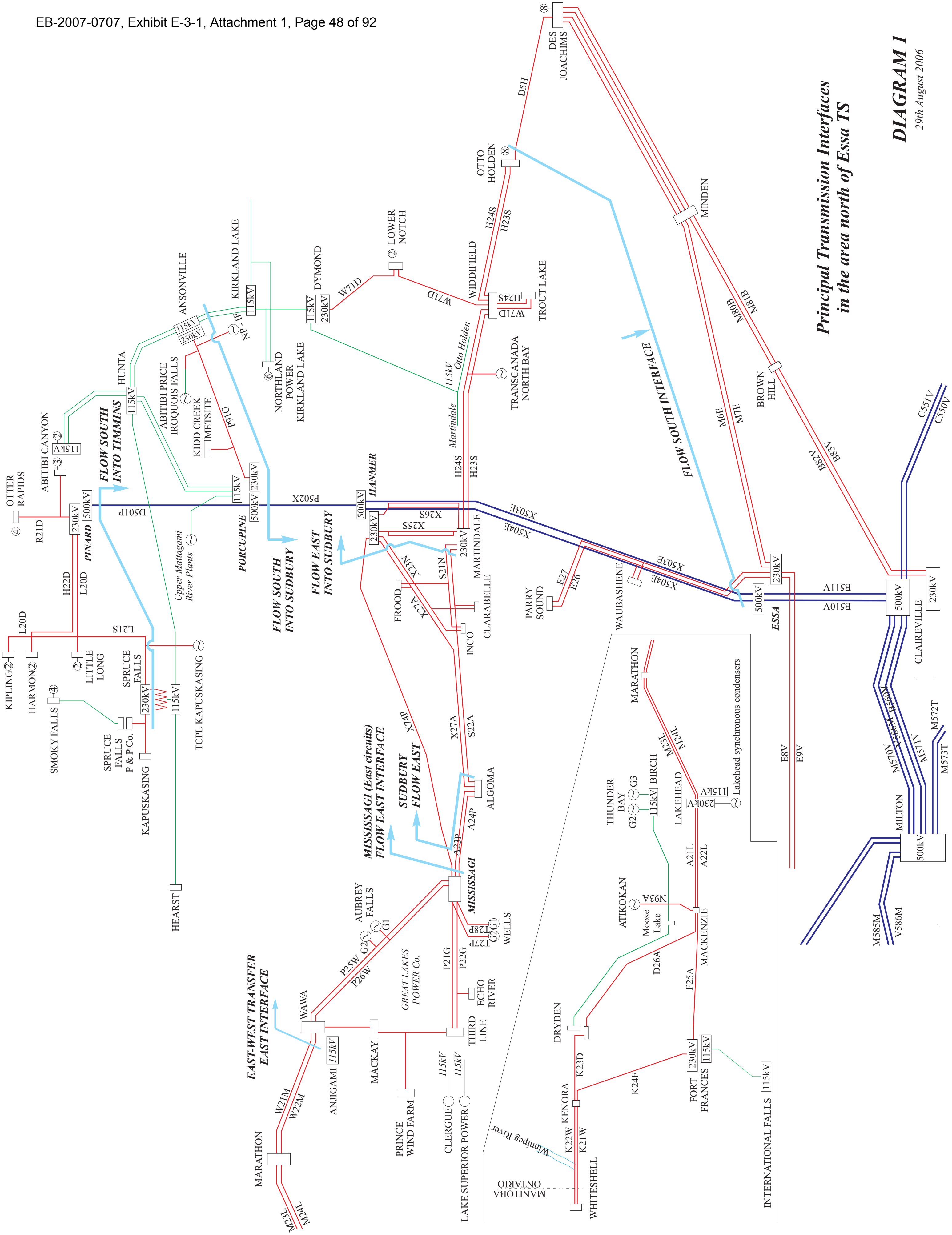


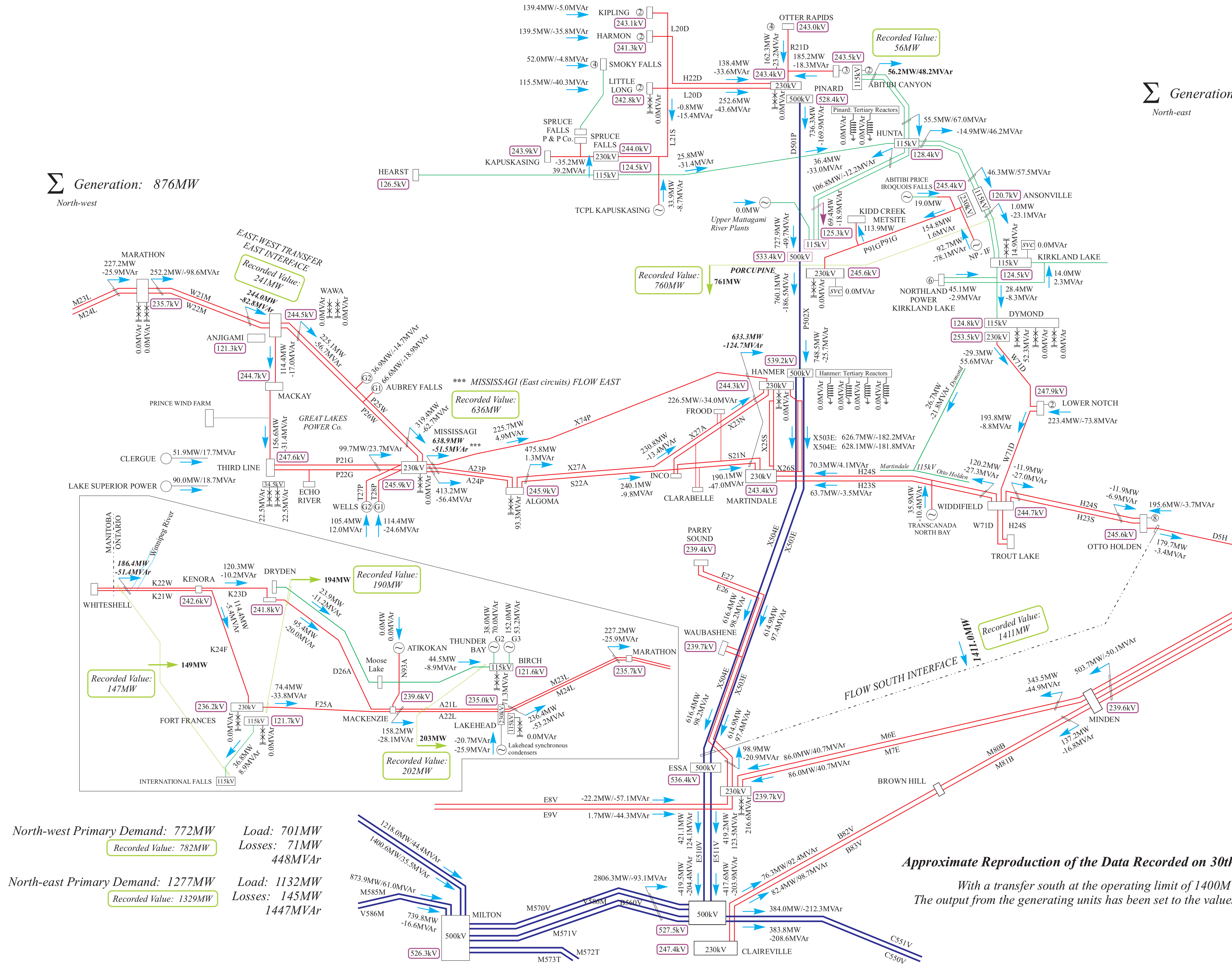
DIAGRAM 1
29th August 2006
Principal Transmission Interfaces
in the area north of Essa TS
DES JOACHIMS
D5H
OTTO HOLDEN
H24S
H23S
LOWER NOTCH
W71D
DYMOND
KIRKLAND LAKE
ANSONVILLE
NORTHLAND POWER KIRKLAND LAKE
WIDDIFIELD
TROUT LAKE
TRANSCANADA NORTH BAY
Otto Holden
Martindale
MINDEN
M80B
M81B
BROWN HILL
B82V
B83V
M6E
M7E
FLOW SOUTH INTERFACE
C551V
C550V
HUNTA
ABITIBI CANYON
OTTER RAPIDS
ABITIBI PRICE IROQUOIS FALLS
KIDD CREEK METSITE
P91G
FLOW SOUTH INTO TIMMINS
PINARD
R21D
H22D
L20D
D501P
P502X
PORCUPINE
Upper Mattagami River Plants
HANMER
X26S
X25S
X503E
X504E
MARTINDALE
FLOW SOUTH INTO SUDBURY
FLOW EAST INTO SUDBURY
X23N
S21N
FROOD
X27A
CLARABELLE
INCO
PARRY SOUND
E27
E26
WAUBASHENE
ESSA
E511V
E510V
CLAREVILLE
KIPLING
HARMON
LITTLE LONG
L21S
SPRUCE FALLS
SMOKY FALLS
SPRUCE FALLS P & P Co.
KAPUSKASING
TCPL KAPUSKASING
HEARST
X74P
S22A
ALGOMA
A24P
A23P
SUDBURY FLOW EAST
MISSISSAGI (East circuits) FLOW EAST INTERFACE
MISSISSAGI
AUBREY FALLS
WELLS
T28P
T27P
P25W
P26W
GREAT LAKES POWER Co.
P21G
P22G
ECHO RIVER
THIRD LINE
WAWA
MACKAY
ANIGAMI
EAST-WEST TRANSFER EAST INTERFACE
W21M
W22M
MARATHON
M23L
M24L
PRINCE WIND FARM
CLERGUE
LAKE SUPERIOR POWER
E8V
E9V
MILTON
M570V
M571V
M572T
M573T
M585M
V586M
MARATHON
M23L
M24L
THUNDER BAY
BIRCH
LAKEHEAD
Lakehead synchronous condensers
A21L
A22L
ATIKOKAN
N93A
Moose Lake
MACKENZIE
D26A
F25A
DRYDEN
K23D
K24F
FORT FRANCES
INTERNATIONAL FALLS
KENORA
K22W
K21W
Winnipeg River
WHITESHELL
MANITOBA
ONTARIO

DIAGRAM 2

26th June 2006

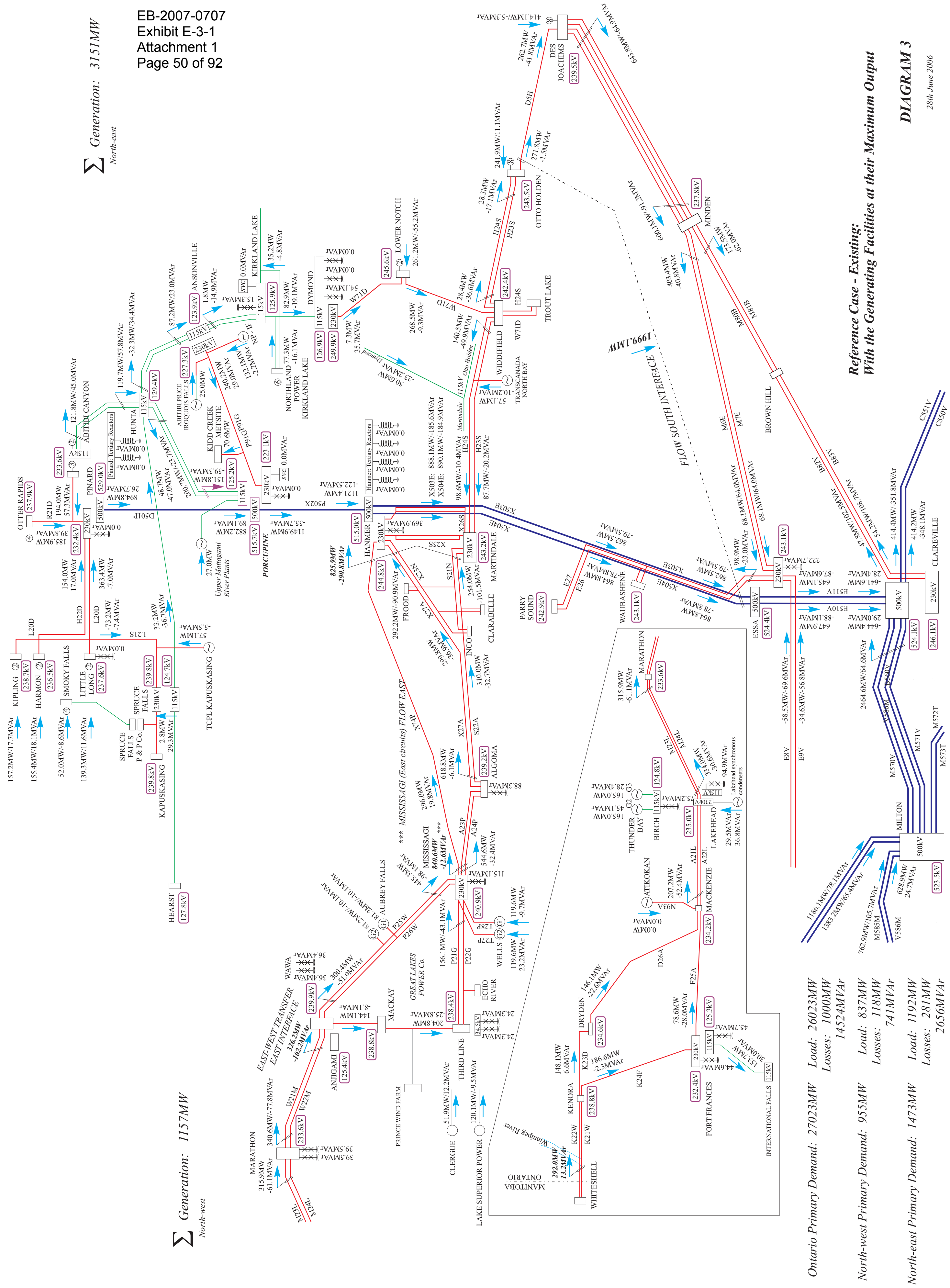
Approximate Reproduction of the Data Recorded on 30th May 2006

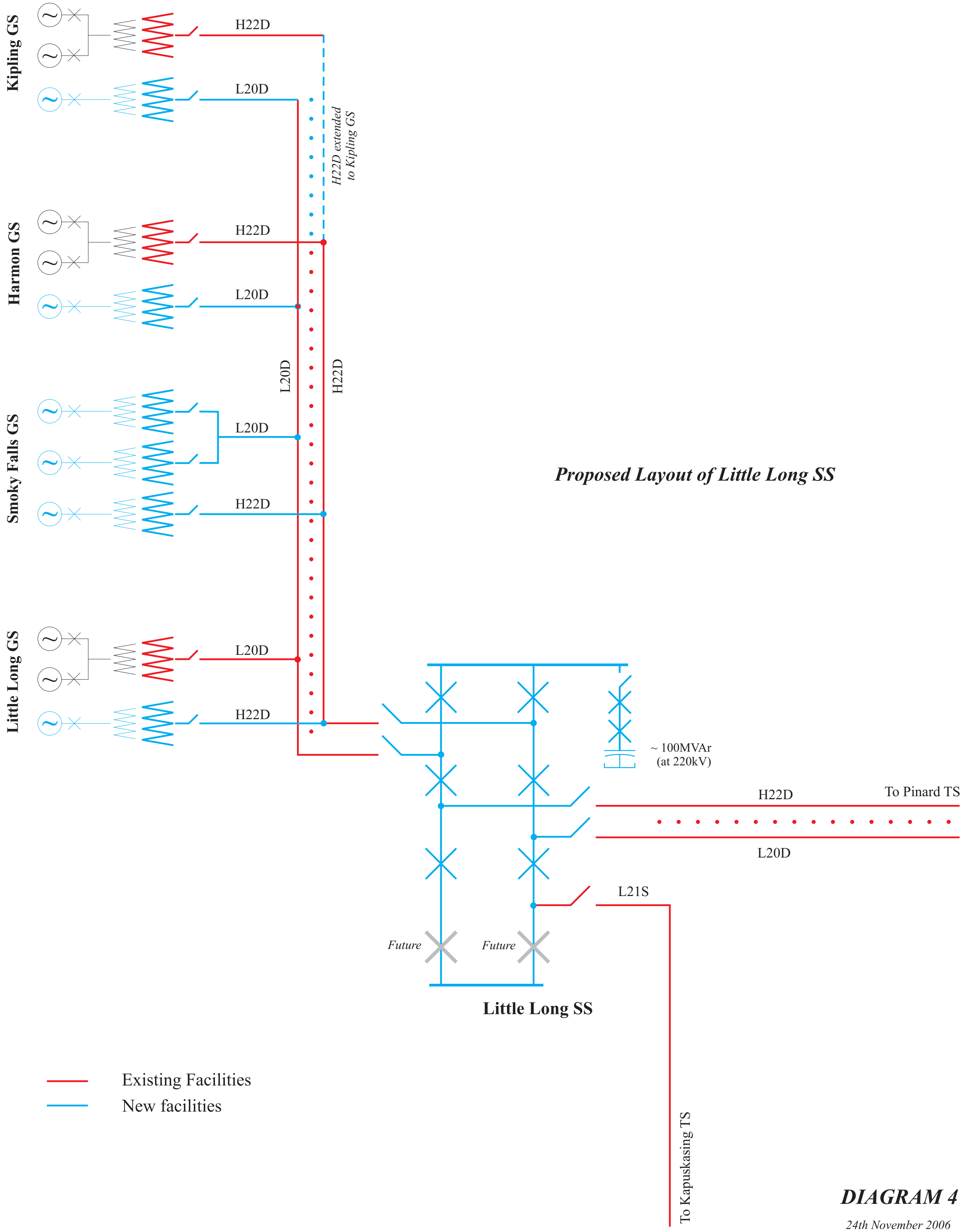
With a transfer south at the operating limit of 1400MW
The output from the generating units has been set to the values recorded



North-west Primary Demand: 772MW
Recorded Value: 782MW
Load: 701MW
Losses: 71MW
448MVAr

North-east Primary Demand: 1277MW
Recorded Value: 1329MW
Load: 1132MW
Losses: 145MW
1447MVAr

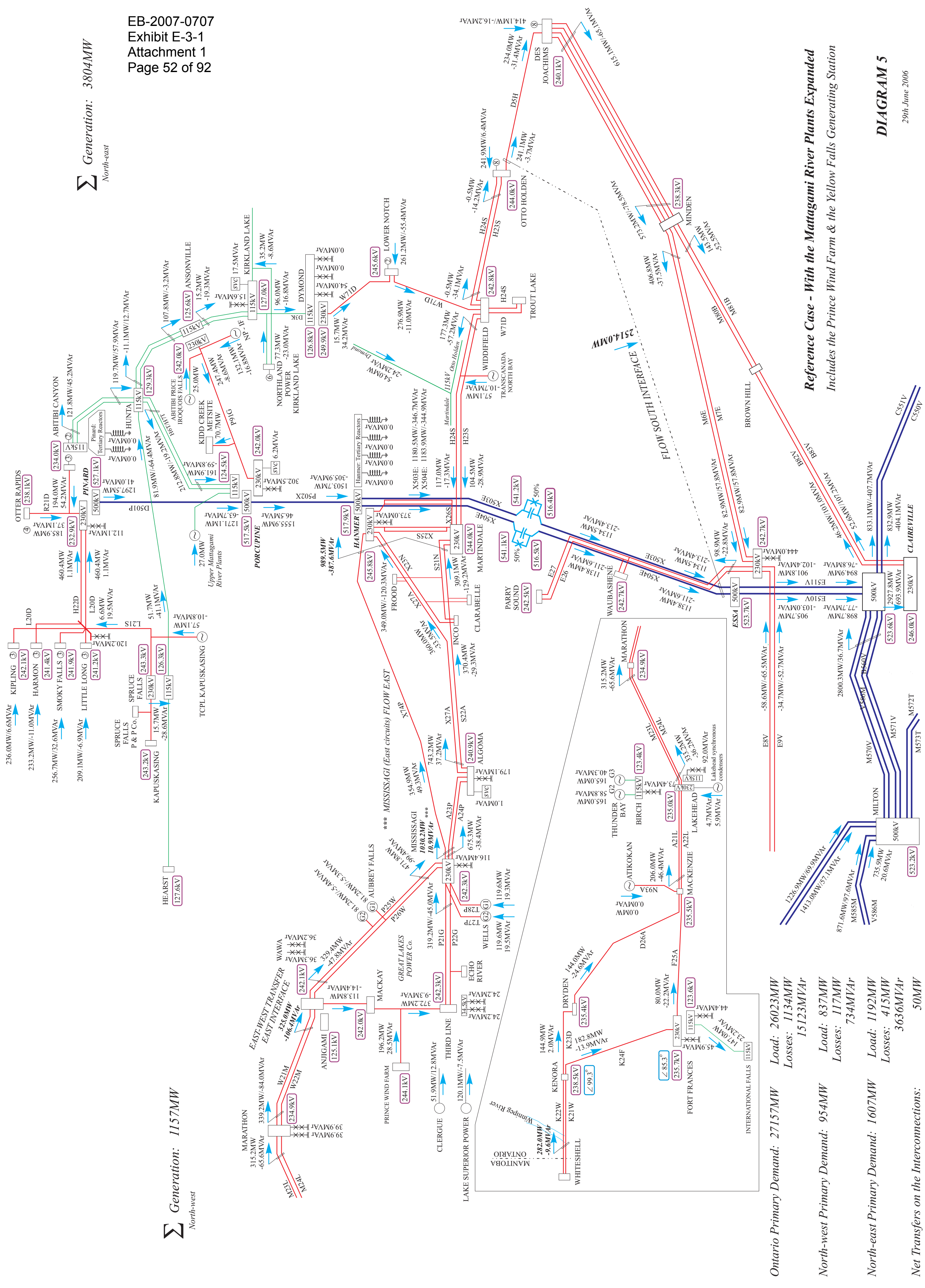

Reference Case - Existing:
With the Generating Facilities at their Maximum Output
DIAGRAM 3
28th June 2006
Σ Generation: 3151MW
North-east
Σ Generation: 1157MW
North-west
FLOW SOUTH INTERFACE
1999.1MW
EAST-WEST TRANSFER
EAST INTERFACE
326.2MW
-102.2MVAr
*** MISSISSAGI (East circuits) FLOW EAST
Ontario Primary Demand: 27023MW
Load: 26023MW
Losses: 1000MW
14524MVAr
North-west Primary Demand: 955MW
Load: 837MW
Losses: 118MW
741MVAr
North-east Primary Demand: 1473MW
Load: 1192MW
Losses: 281MW
2656MVAr

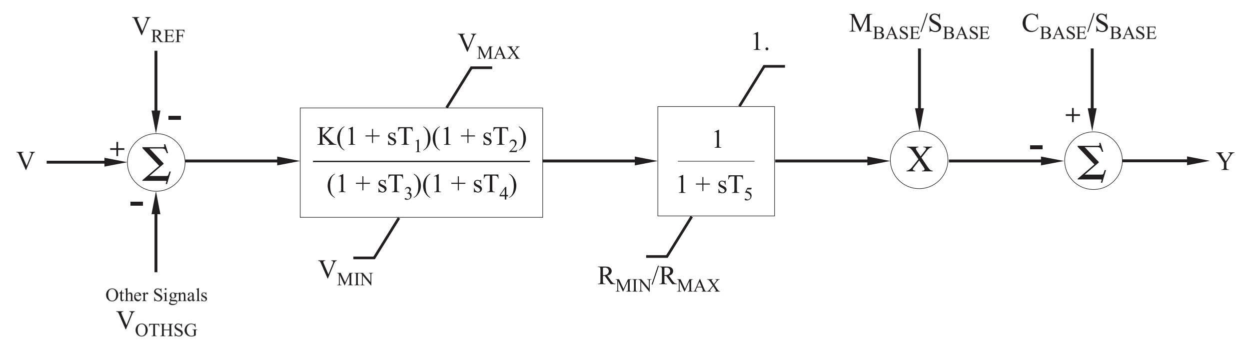


Proposed Layout of Little Long SS

DIAGRAM 4

24th November 2006


Reference Case - With the Mattagami River Plants Expanded
Includes the Prince Wind Farm & the Yellow Falls Generating Station
DIAGRAM 5
29th June 2006
Σ Generation: 3804MW
North-east
Σ Generation: 1157MW
North-west
Ontario Primary Demand: 27157MW
Load: 26023MW
Losses: 1134MW
15123MVAr
North-west Primary Demand: 954MW
Load: 837MW
Losses: 117MW
734MVAr
North-east Primary Demand: 1607MW
Load: 1192MW
Losses: 415MW
3636MVAr
Net Transfers on the Interconnections: 50MW
FLOW SOUTH INTERFACE
2514.0MW
EAST-WEST TRANSFER
EAST INTERFACE
225.0MW
-106.4MVAr
MISSISSAGI (East circuits) FLOW EAST
DES JOACHIMS
OTTO HOLDEN
MINDEN
BROWN HILL
CLAIREVILLE
ESSA
WAUBASHENE
PARRY SOUND
MARTINDALE
CLARABELLE
INCO
FROOD
HANMER
PORCUPINE
PINARD
OTTER RAPIDS
ABITIBI CANYON
HUNTA
KIDD CREEK METSITE
ANSONVILLE
KIRKLAND LAKE
DYMOND
LOWER NOTCH
WIDDIFIELD
TROUT LAKE
KIPLING
HARMON
SMOKY FALLS
LITTLE LONG
SPRUCE FALLS
KAPUSKASING
TCPL KAPUSKASING
HEARST
ALGOMA
MISSISSAGI
AUBREY FALLS
WELLS
ECHO RIVER
THIRD LINE
MACKAY
WAWA
ANJIGAMI
PRINCE WIND FARM
CLERGUE
LAKE SUPERIOR POWER
MARATHON
THUNDER BAY
BIRCH
LAKEHEAD
MACKENZIE
ATIKOKAN
DRYDEN
KENORA
WHITESHELL
FORT FRANCES
INTERNATIONAL FALLS
MILTON
MANITOBA
ONTARIO
Upper Mattagami River Plants



Values used in the Transient Stability Analysis

K	32	
R_{MIN} Reactor Minimum MVAr Output	0.0MVAr	
V_{MAX}	1.0	
V_{MIN}	0.0	
T_1	0.00 sec	
T_2	0.00 sec	
T_3	0.02 sec	
T_4	0.00 sec	
T_5	0.00 sec	
	Porcupine TS	Kirkland Lake TS
C_{BASE} Capacitor MVAr Output	300MVAr	200MVAr
M_{BASE} MVAr Range of SVC	400MVAr	300MVAr

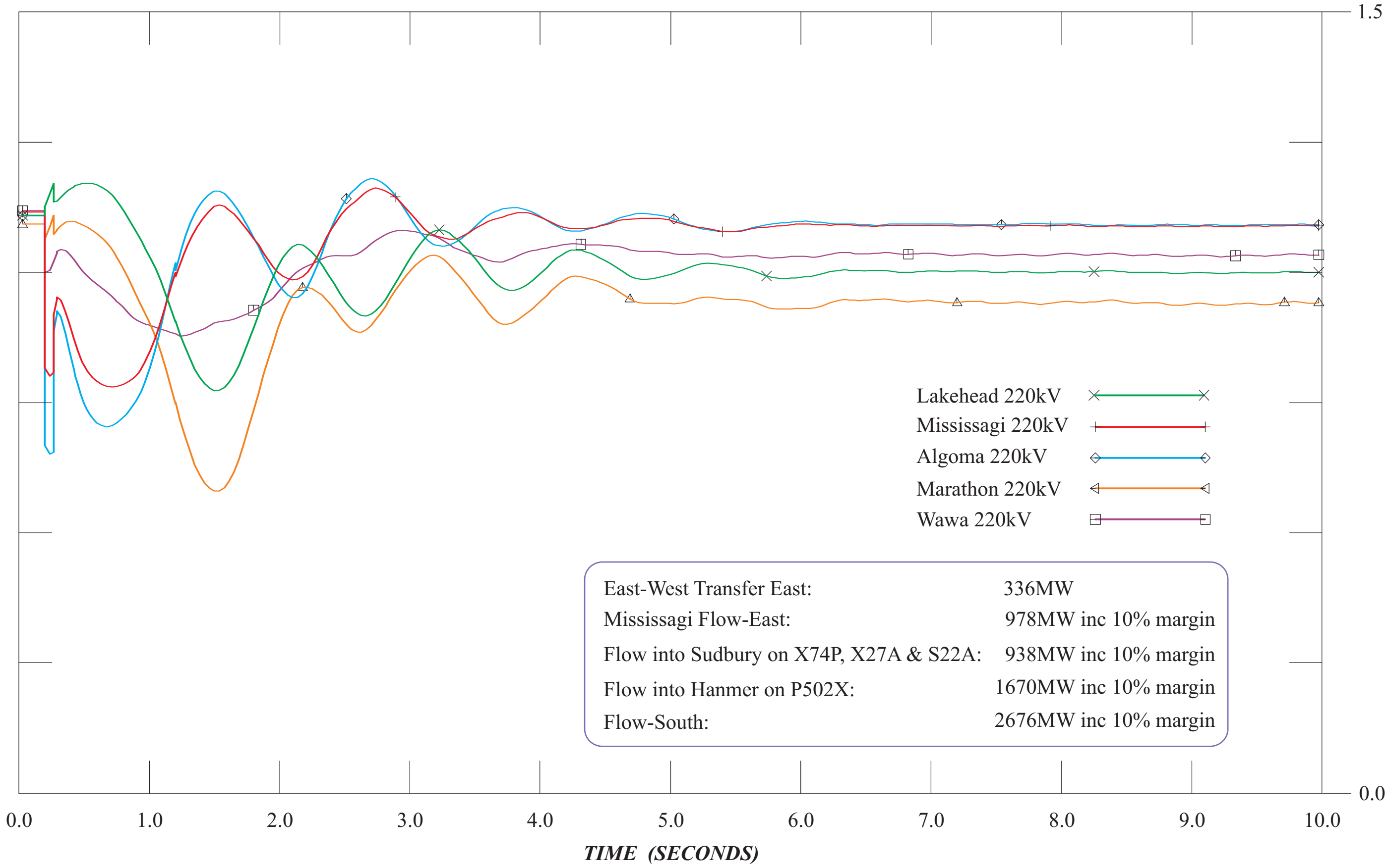
CSVGN1 Static VAr Compensator Model

Data assumed for the Transient Analysis

DIAGRAM 6

5th July 2006

Voltages with the Output from the Prince Wind Farm at 150MW



Voltages with the Output from the Prince Wind Farm at 175MW

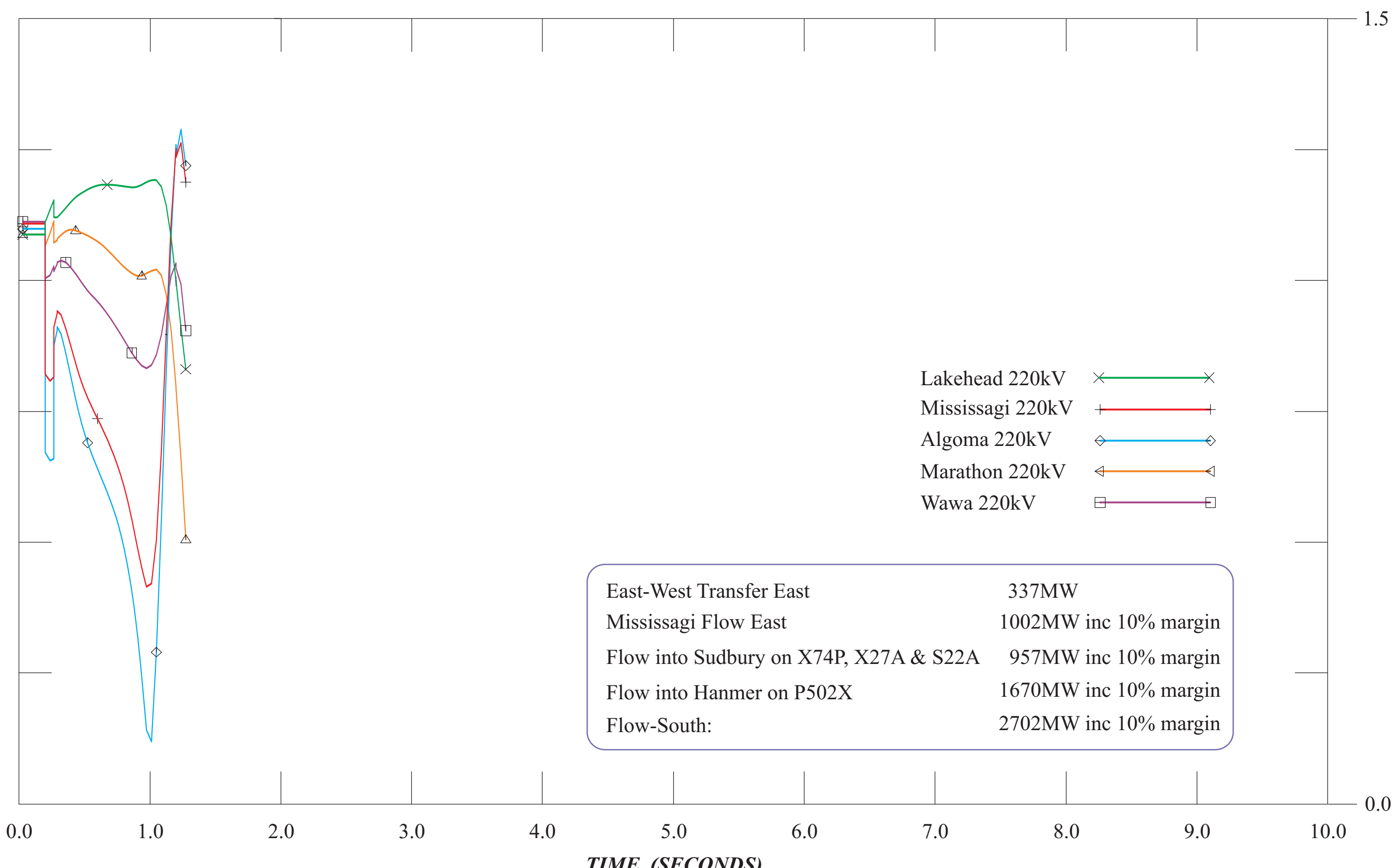
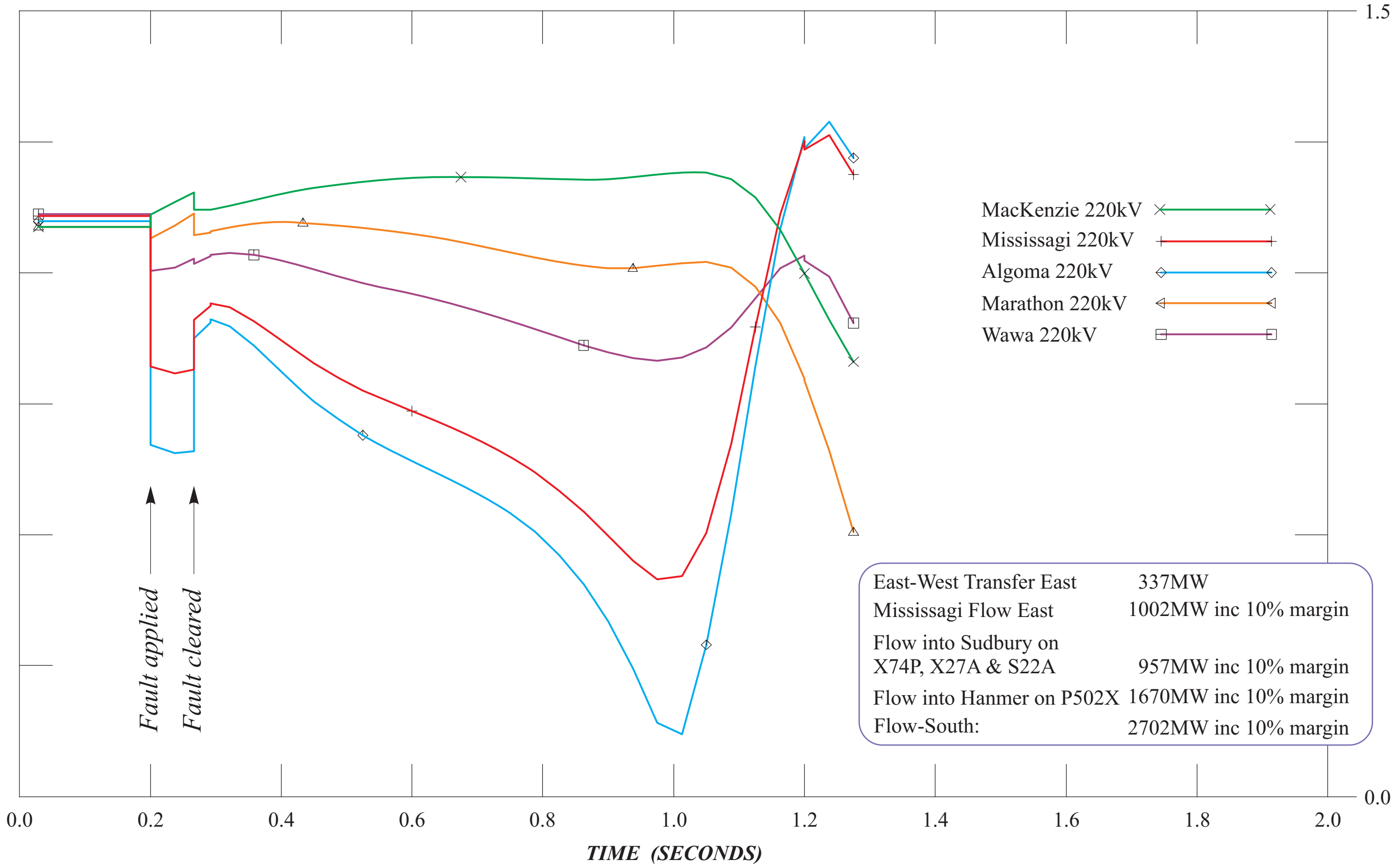


DIAGRAM 7

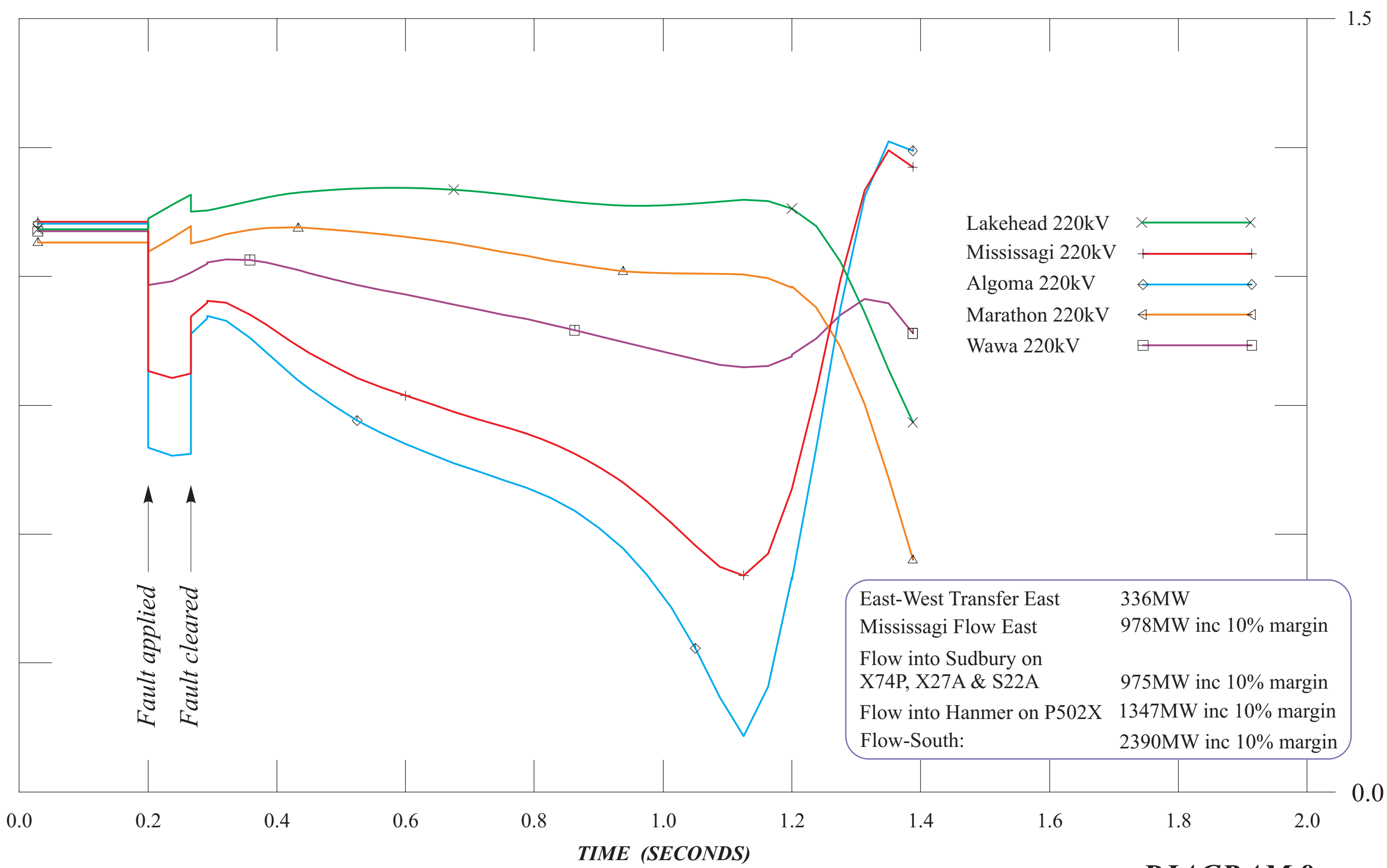
Transient Voltages in Response to a Contingency Involving the 500kV Circuit P502X

17th July 2006

Copy of the lower half of Diagram 7



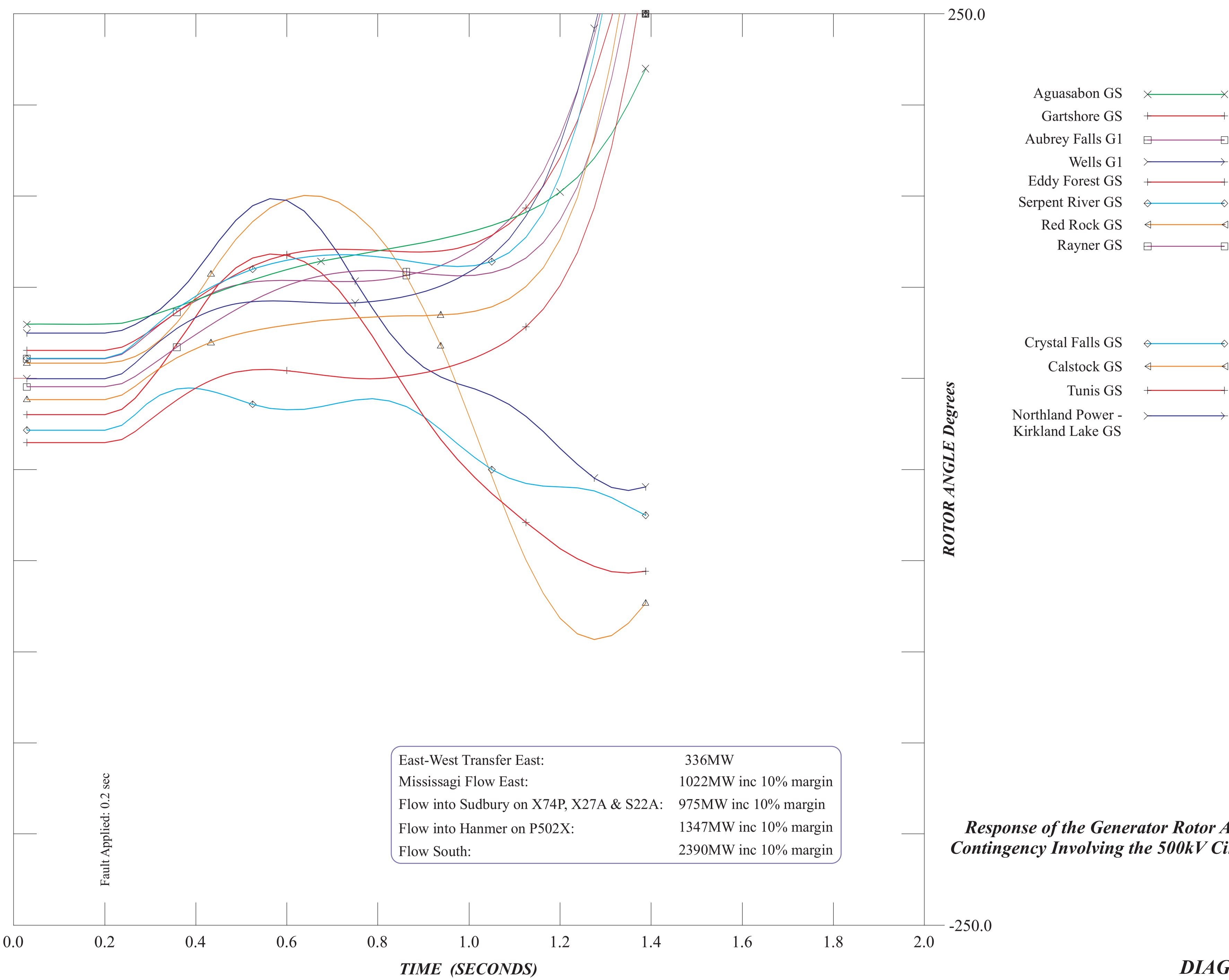
With reduced Flow-South into Sudbury



Transient Voltages in Response to a Contingency Involving the 500kV Circuit P502X

DIAGRAM 8

17th July 2006



Response of the Generator Rotor Angles to a Contingency Involving the 500kV Circuit P502X

DIAGRAM 9

19th August 2006

Voltages West of Sudbury with a +300/-100MVAr SVC at Marathon TS

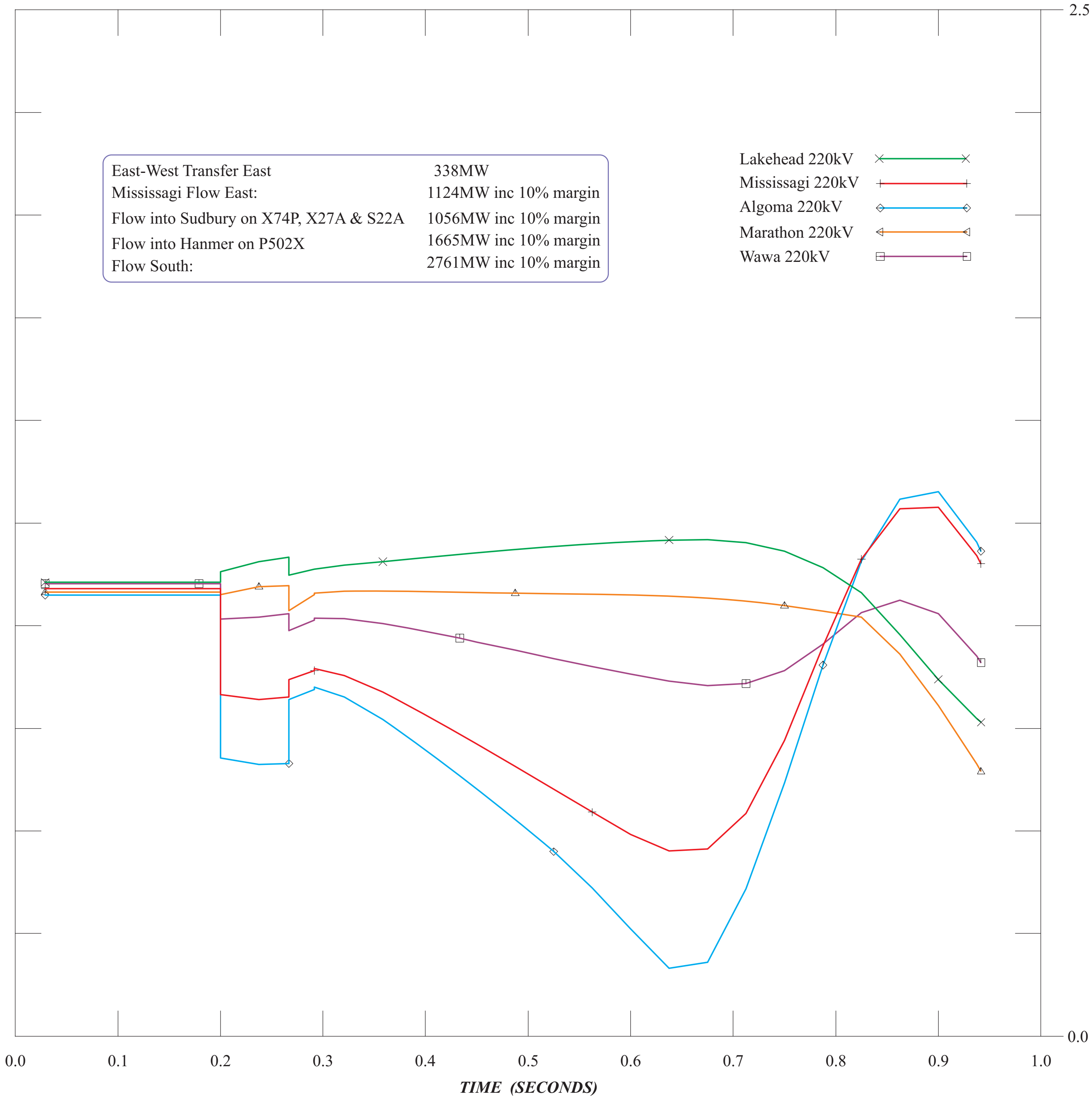
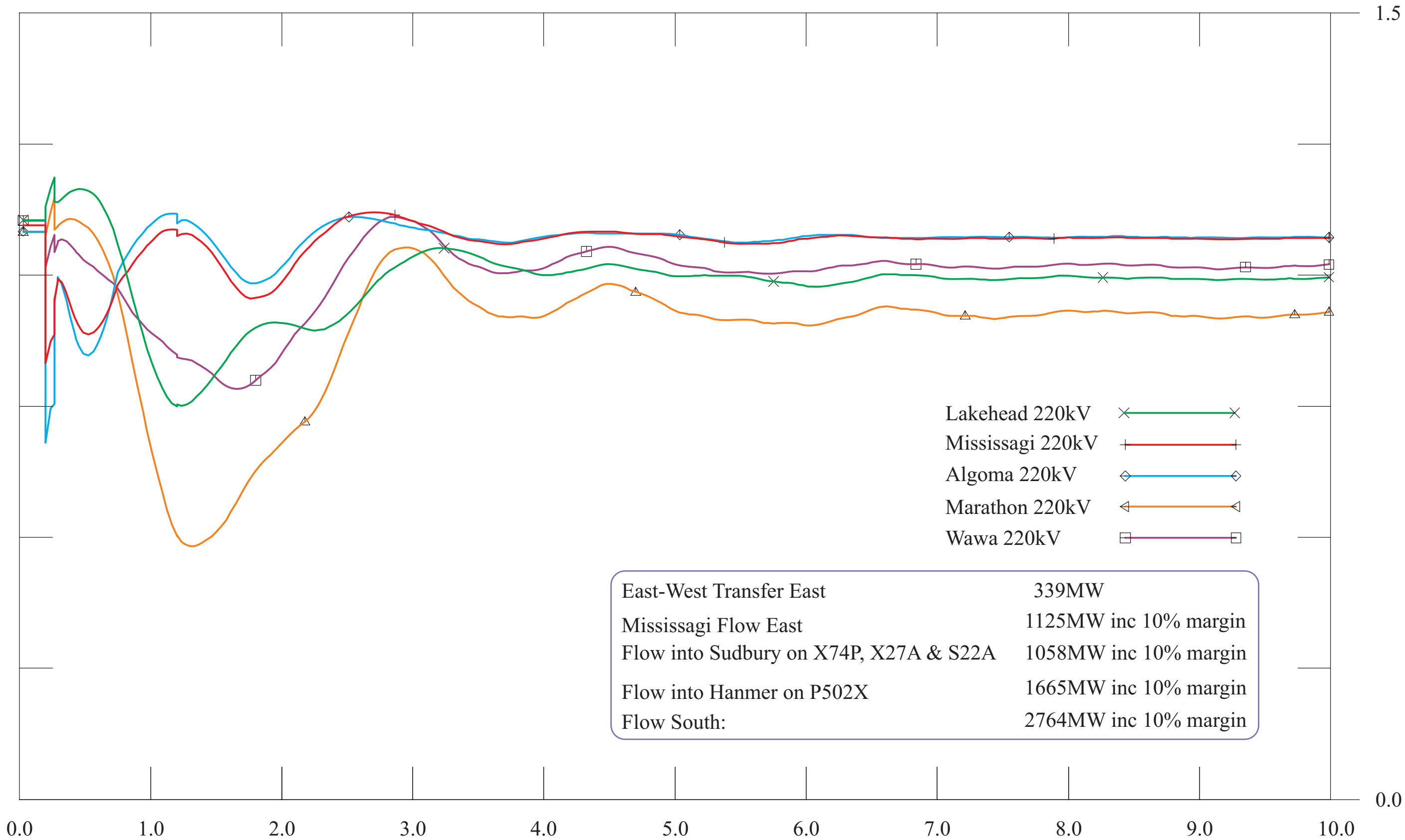


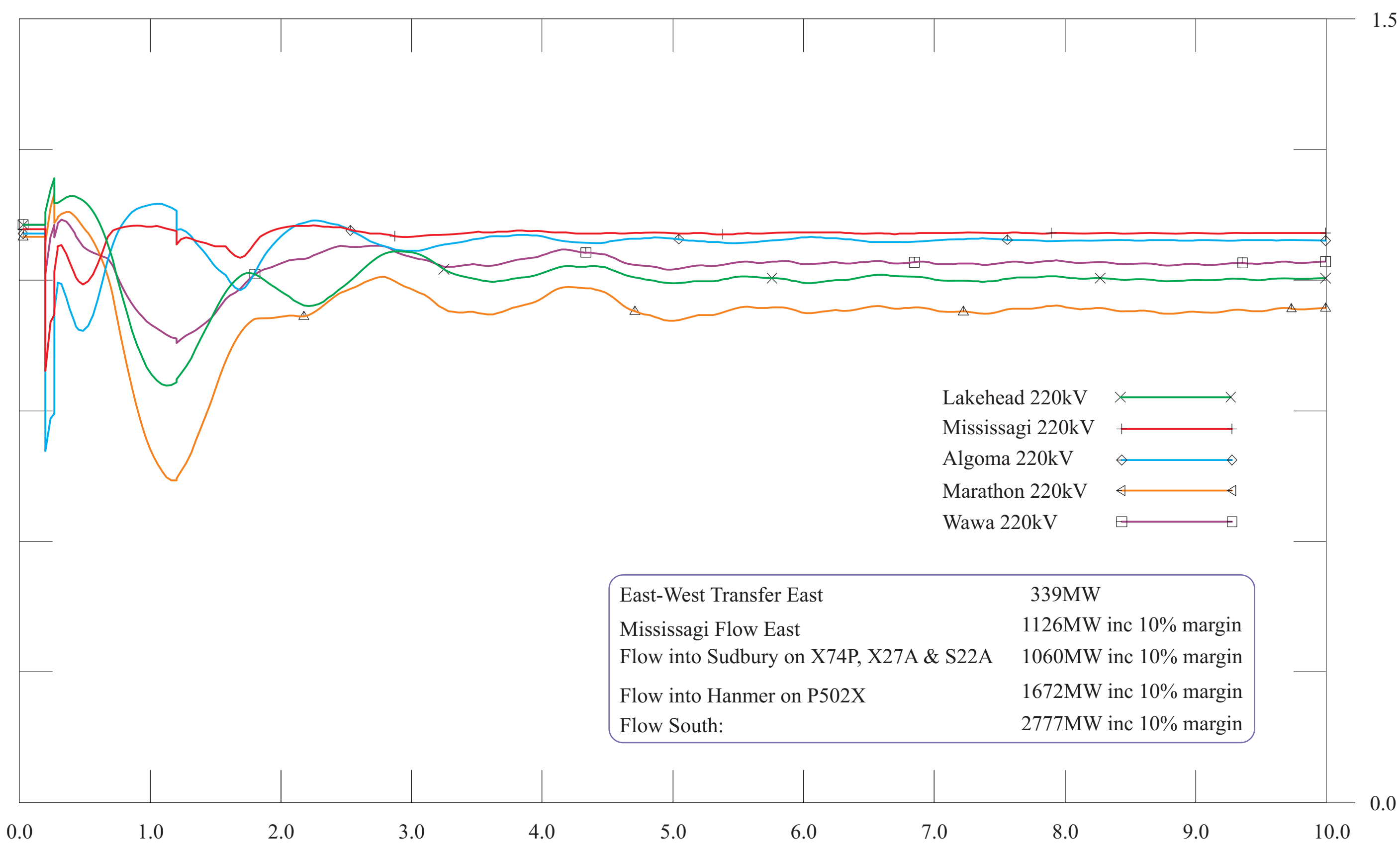
DIAGRAM 10

17th July 2006

Voltages West of Sudbury with a +300/-100MVAr SVC at Algoma TS



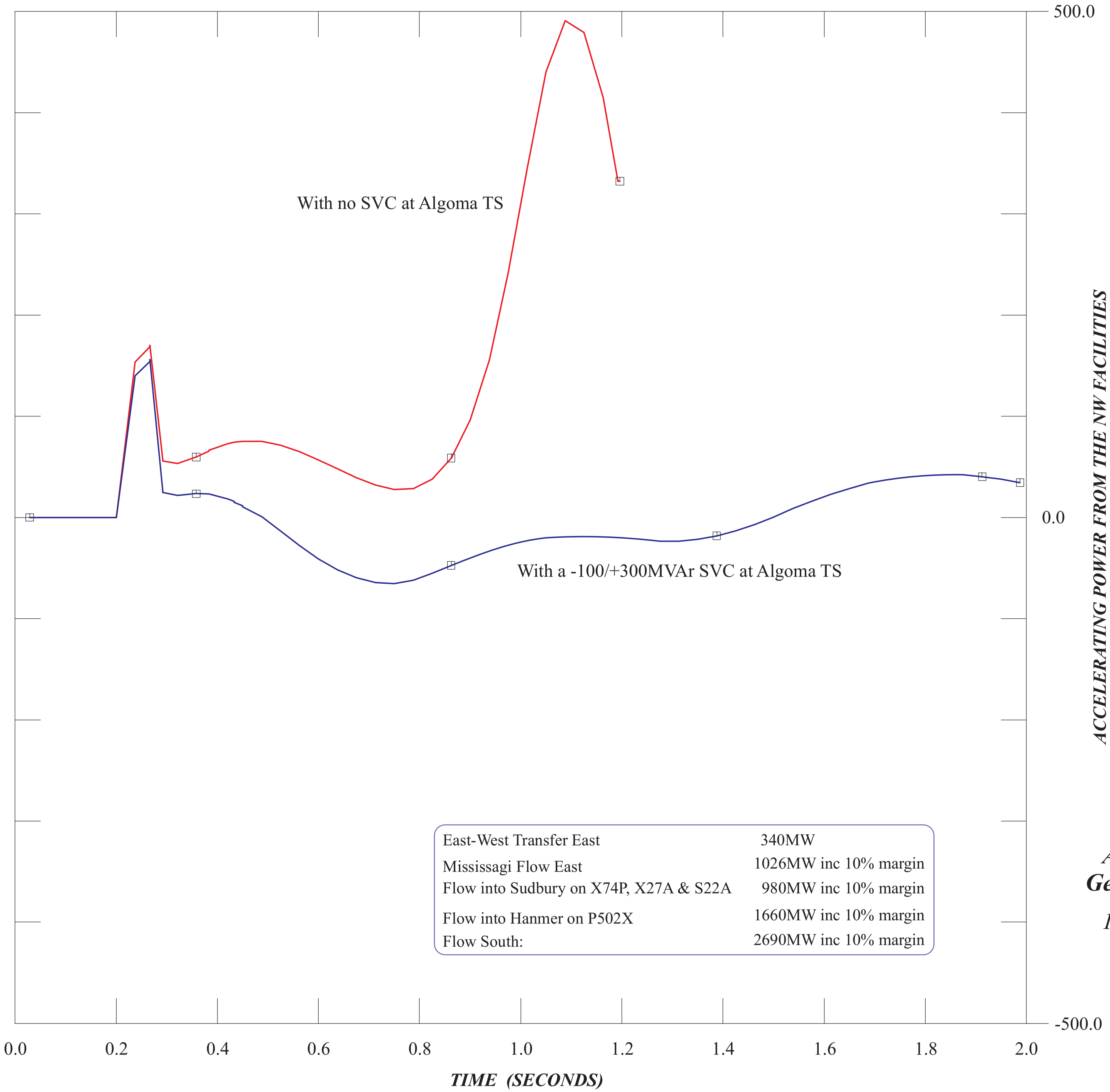
Voltages West of Sudbury with a +300/-100MVAr SVC at Mississagi TS



Transient Voltages in Response to a Contingency Involving the 500kV Circuit P502X

DIAGRAM 11

17th July 2006

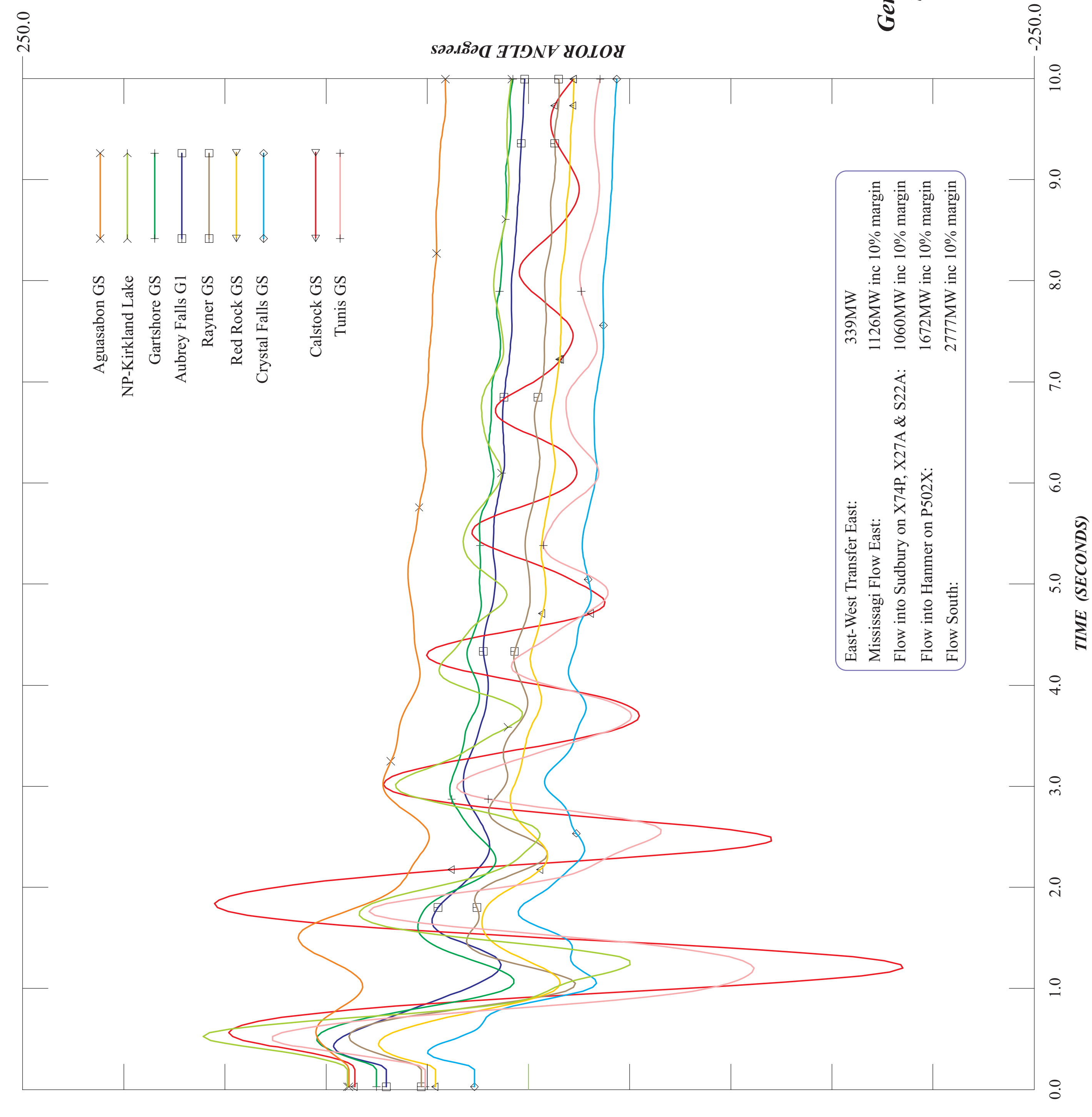


Accelerating Power from the Generating Facilities in the NW

In response to a 3-phase fault at Hanmer TS on circuit P502X

DIAGRAM 12

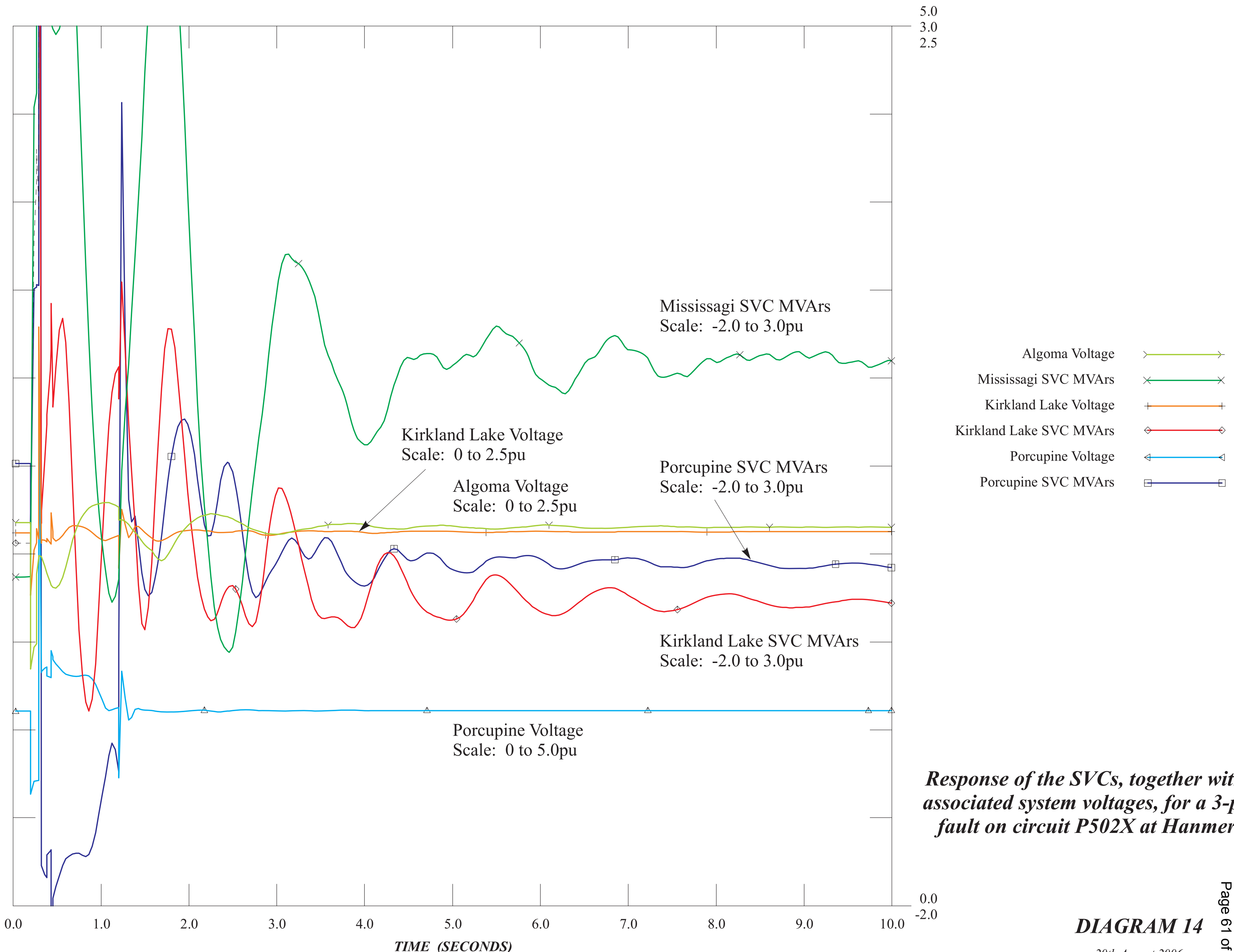
5th July 2006



Generator Rotor Angle Responses to a 3-phase fault on circuit P502X at Hanmer TS

DIAGRAM 13

20th August 2006



Response of the SVCs, together with the associated system voltages, for a 3-phase fault on circuit P502X at Hanmer TS

DIAGRAM 14

20th August 2006

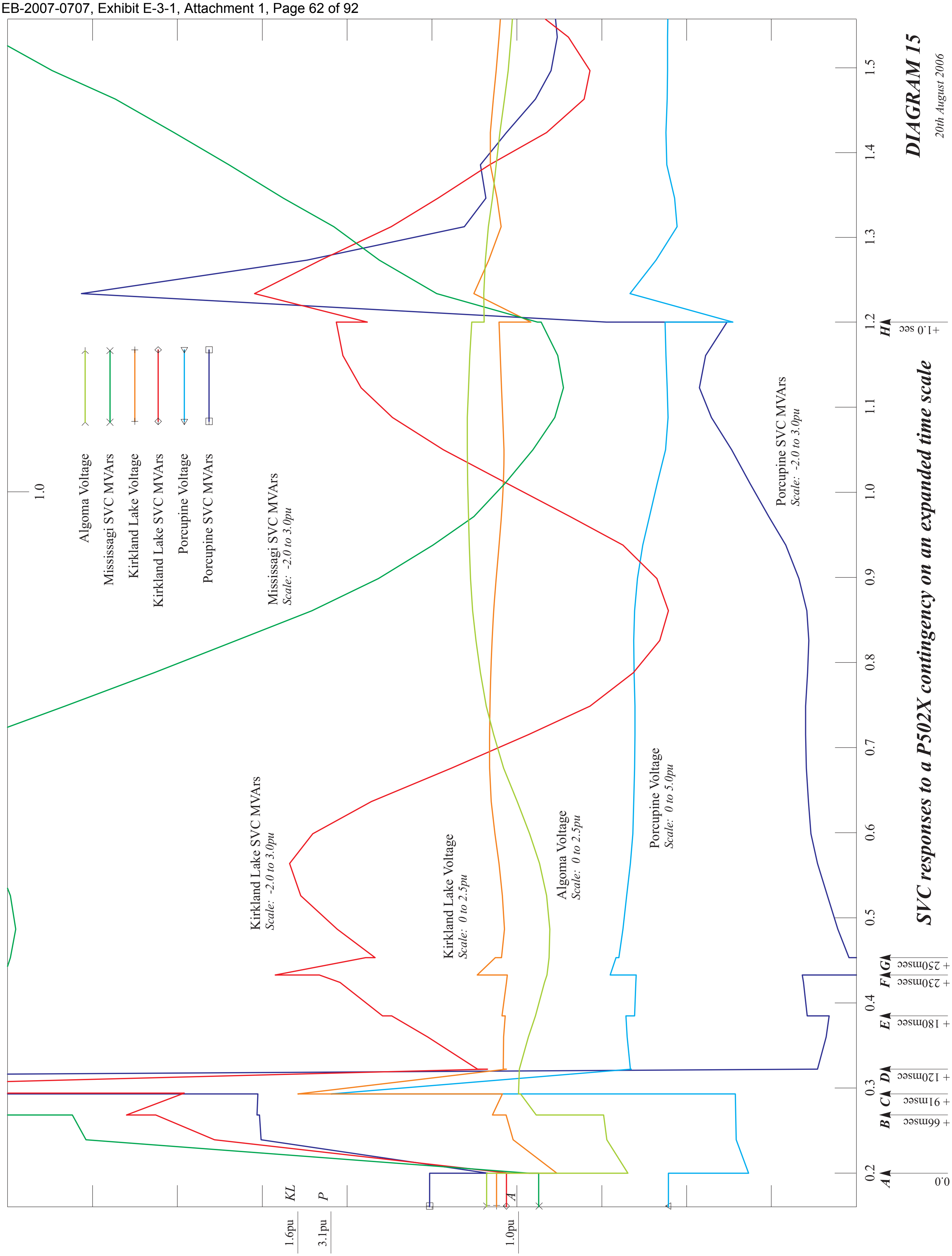


DIAGRAM 15

20th August 2006

SVC responses to a P502X contingency on an expanded time scale

Reference Case - With the Mattagami River Plants Expanded

Includes the Prince Wind Farm & the Yellow Falls Generating Station

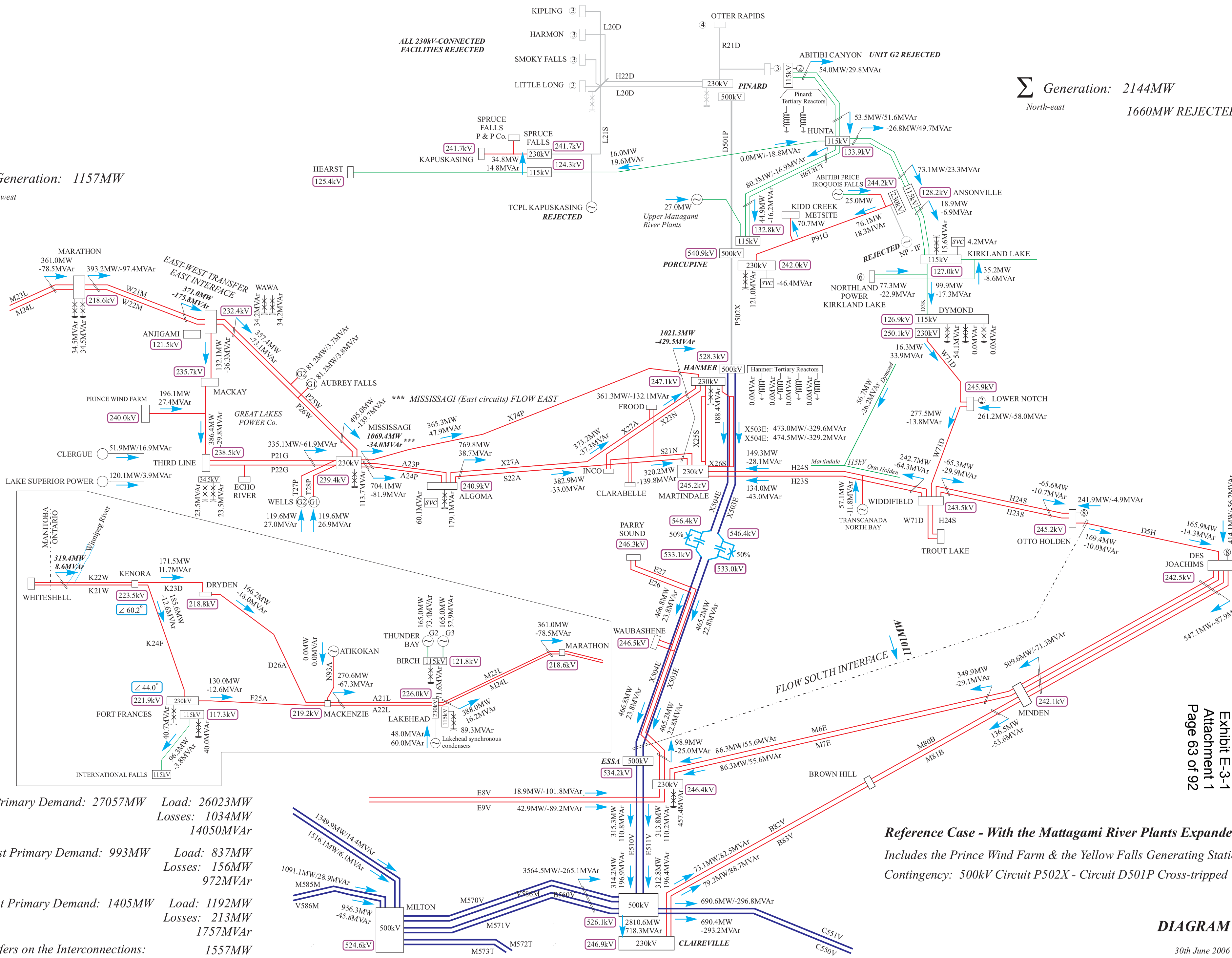
Contingency: 500kV Circuit P502X - Circuit D501P Cross-tripped

DIAGRAM 16

30th June 2006

$\sum$ *Generation: 2144MW*
North-east
1660MW REJECTED

$\sum$ *Generation: 1157MW*
North-west



Ontario Primary Demand: 27057MW Load: 26023MW
Losses: 1034MW
14050MVAr

North-west Primary Demand: 993MW Load: 837MW
Losses: 156MW
972MVAr

North-east Primary Demand: 1405MW Load: 1192MW
Losses: 213MW
1757MVAr

Net Transfers on the Interconnections: 1557MW

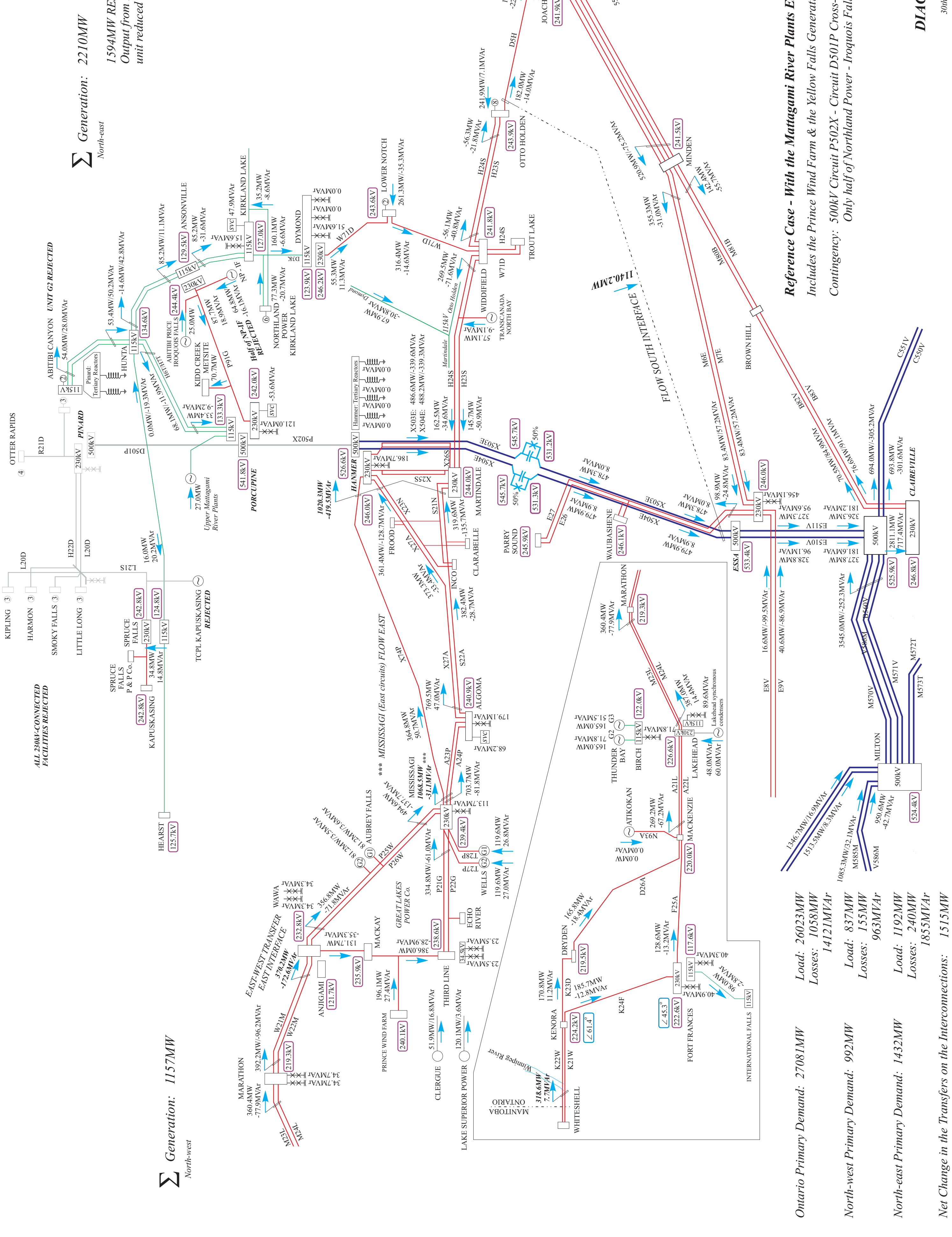
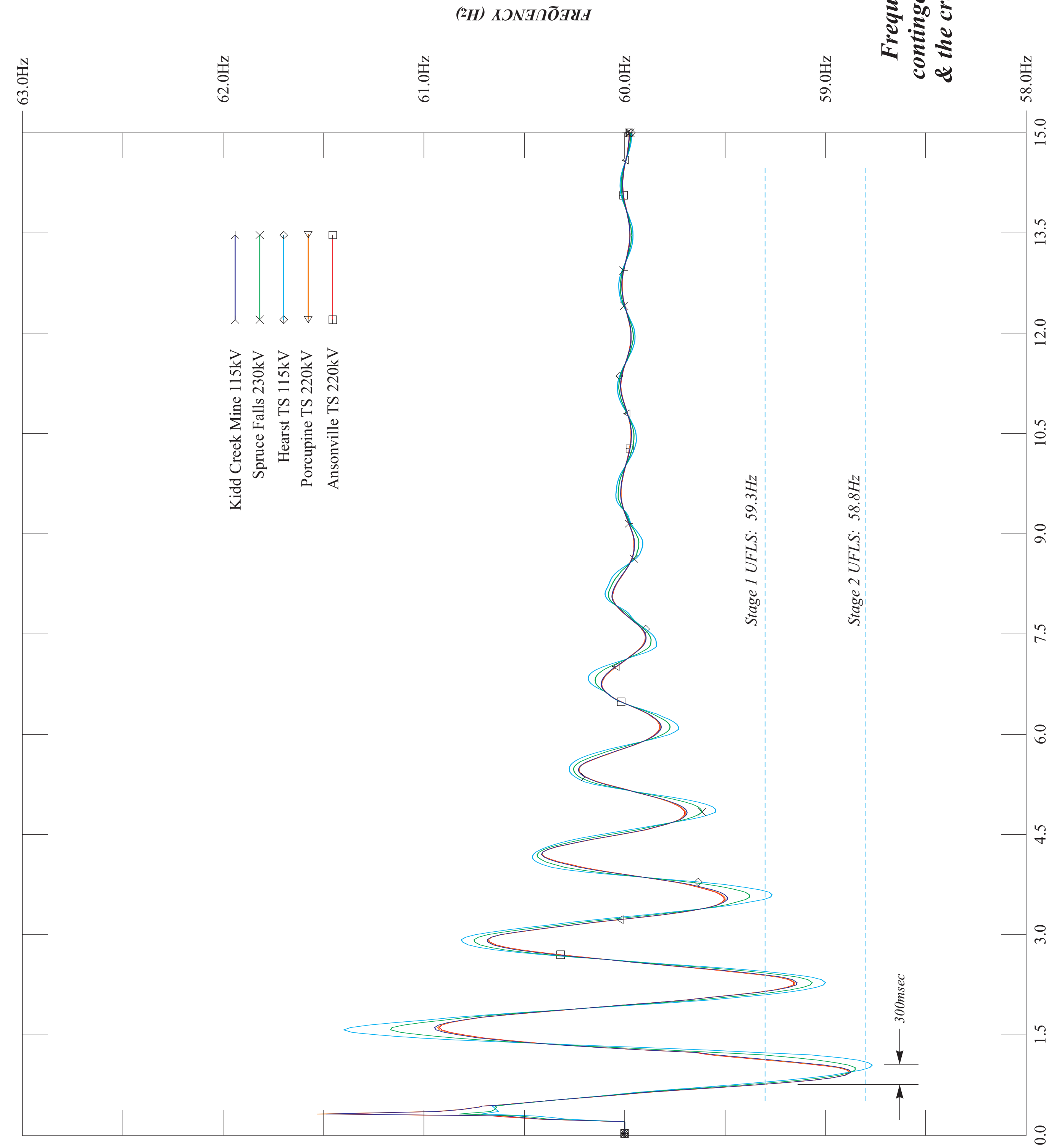


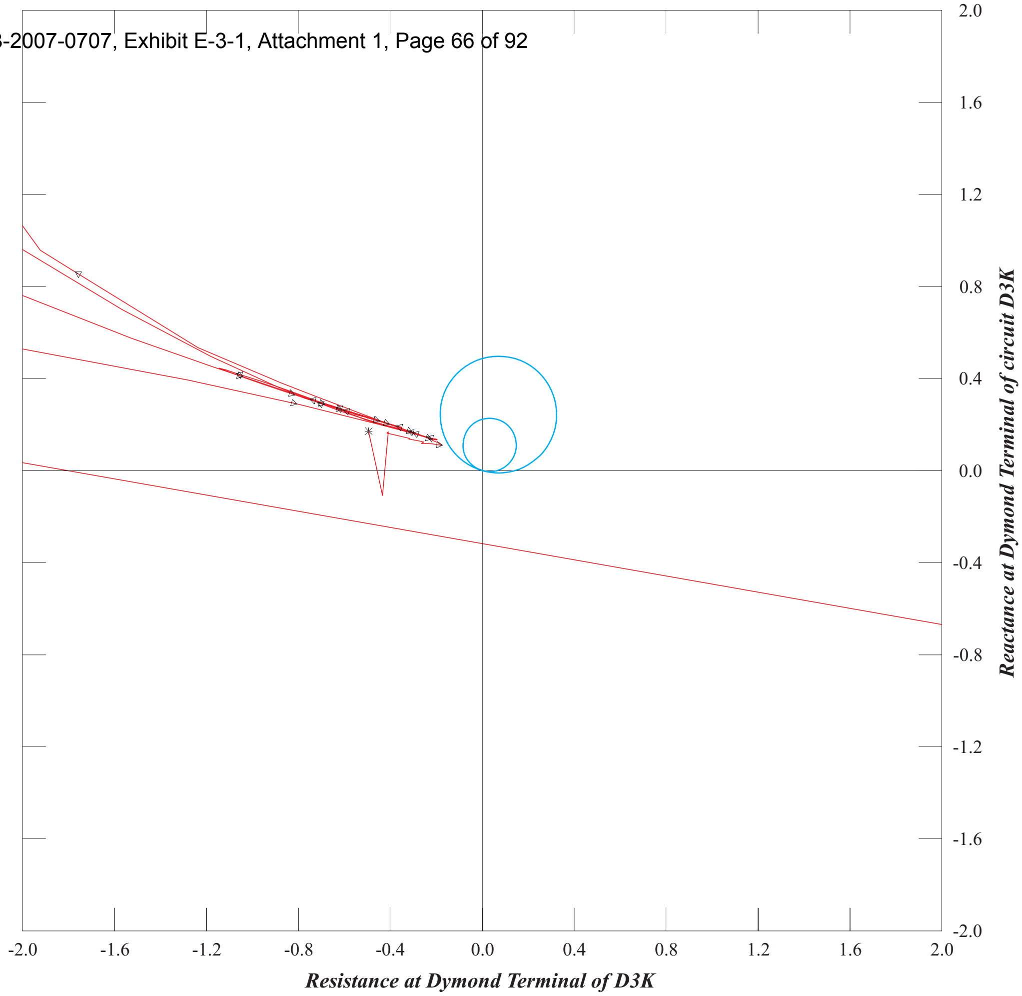
DIAGRAM 17
30th June 2006
Reference Case - With the Mattagami River Plants Expanded
Includes the Prince Wind Farm & the Yellow Falls Generating Station
Contingency: 500kV Circuit P502X - Circuit D501P Cross-tripped
Only half of Northland Power - Iroquois Falls Rejected
Ontario Primary Demand: 27081MW
Load: 26023MW
Losses: 1058MW
14121MVAr
North-west Primary Demand: 992MW
Load: 837MW
Losses: 155MW
963MVAr
North-east Primary Demand: 1432MW
Load: 1192MW
Losses: 240MW
1855MVAr
Net Change in the Transfers on the Interconnections: 1515MW
Σ Generation: 2210MW
North-east
1594MW REJECTED
Output from NP-IF steam unit reduced by 50%
Σ Generation: 1157MW
North-west
ALL 230kV-CONNECTED FACILITIES REJECTED
UNIT G2 REJECTED
Half of NP-IF REJECTED
TCPL KAPUSKASING REJECTED
FLOW SOUTH INTERFACE
1140.2MW
EAST-WEST TRANSFER EAST INTERFACE
370.2MW
-172.6MVAr
MISSISSAGI (East circuits) FLOW EAST
1020.3MW
-419.5MVAr
OTTER RAPIDS
ABITIBI CANYON
PINARD
HUNTA
ANSONVILLE
KIRKLAND LAKE
DYMOND
LOWER NOTCH
KIDD CREEK
METSITE
ABITIBI PRICE IROQUOIS FALLS
NORTHLAND POWER KIRKLAND LAKE
PORCUPINE
Upper Mattagami River Plants
KIPLING
HARMON
SMOKY FALLS
LITTLE LONG
SPRUCE FALLS
SPRUCE FALLS P & P Co.
KAPUSKASING
HEARST
HANMER
WIDDIFIELD
TRANSCANADA NORTH BAY
OTTO HOLDEN
TROUT LAKE
DES JOACHIMS
MINDEN
BROWN HILL
CLAREVILLE
ESSA
WAUBASHENE
PARRY SOUND
MARTINDALE
CLARABELLE
FROOD
INCO
ALGOMA
MISSISSAGI
AUBREY FALLS
WELLS
WAWA
MACKAY
GREAT LAKES POWER Co.
ECHO RIVER
THIRD LINE
ANJIGAMI
PRINCE WIND FARM
CLERGUE
LAKE SUPERIOR POWER
MARATHON
MILTON
THUNDER BAY
BIRCH
LAKEHEAD
Lakehead synchronous condensers
ATIKOKAN
MACKENZIE
DRYDEN
KENORA
FORT FRANCES
INTERNATIONAL FALLS
WHITESHELL
MANITOBA
ONTARIO
Winnipeg River

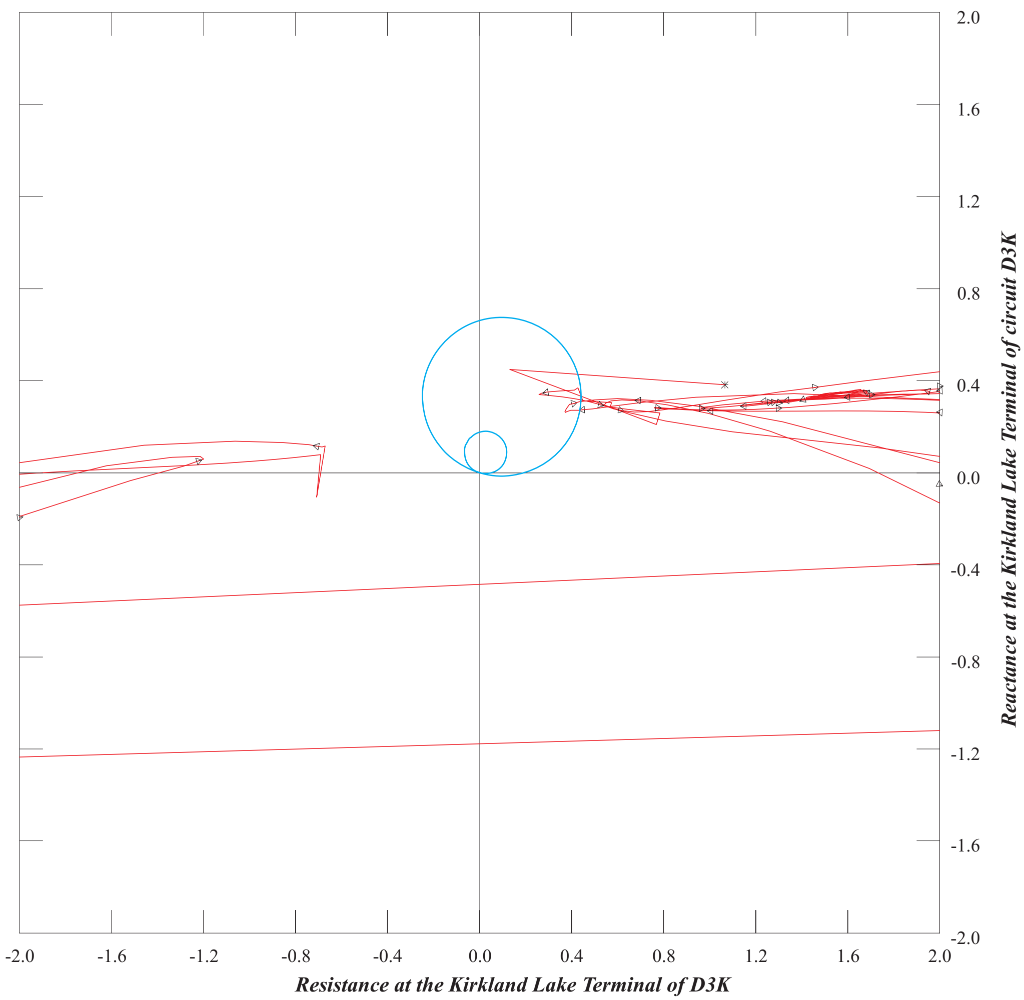
Frequency Response following a contingency involving circuit P502X & the cross-tripping of circuit D501P

DIAGRAM 18

20th August 2006





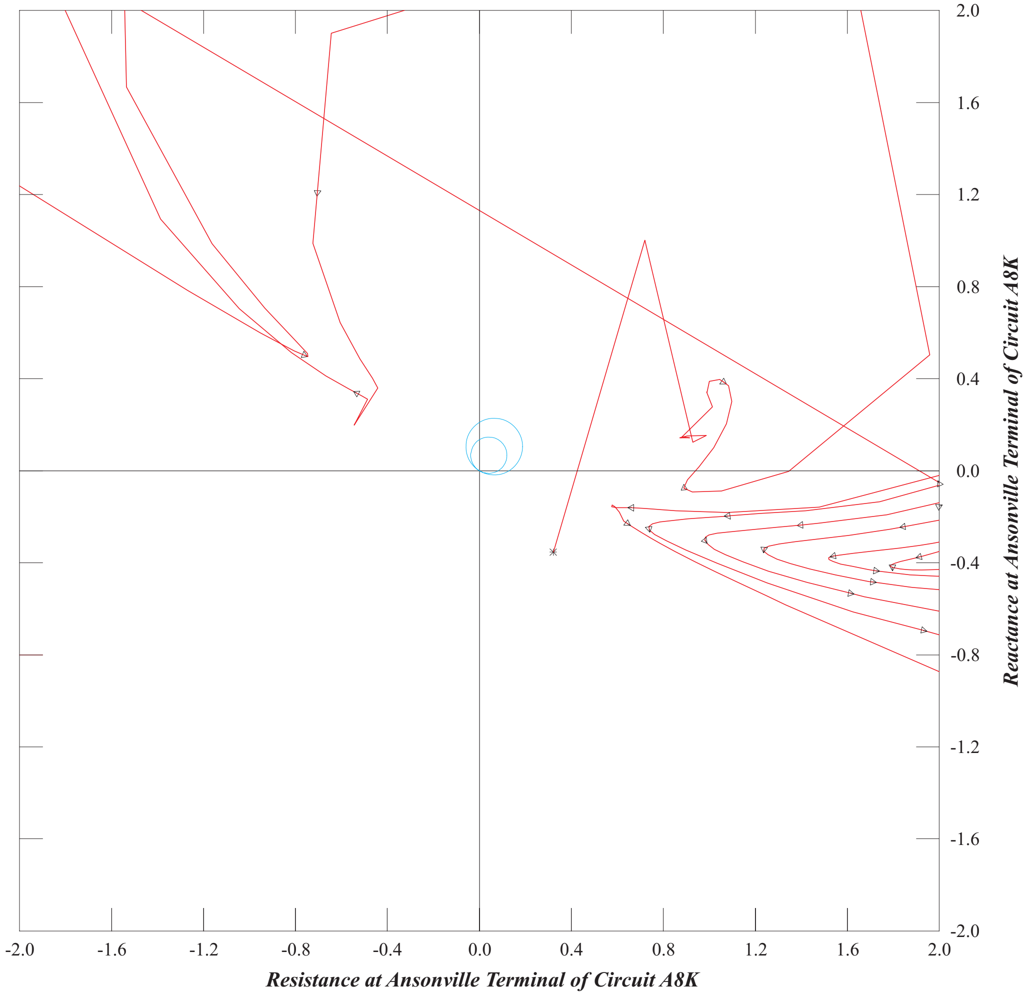


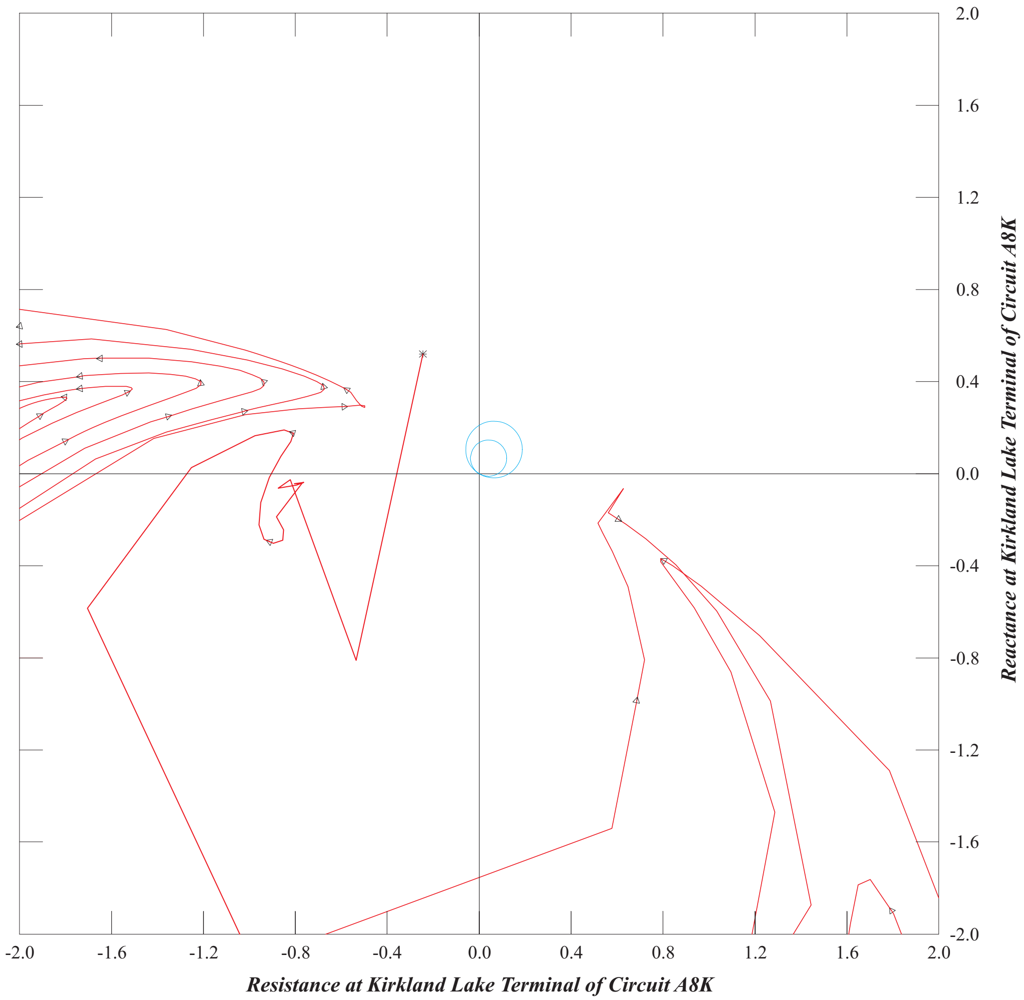
Apparent Impedance Loci for 115kV circuit D3K

For a 500kV 3-phase fault on circuit P502X at Hanmer TS

DIAGRAM 19

20th December 2006



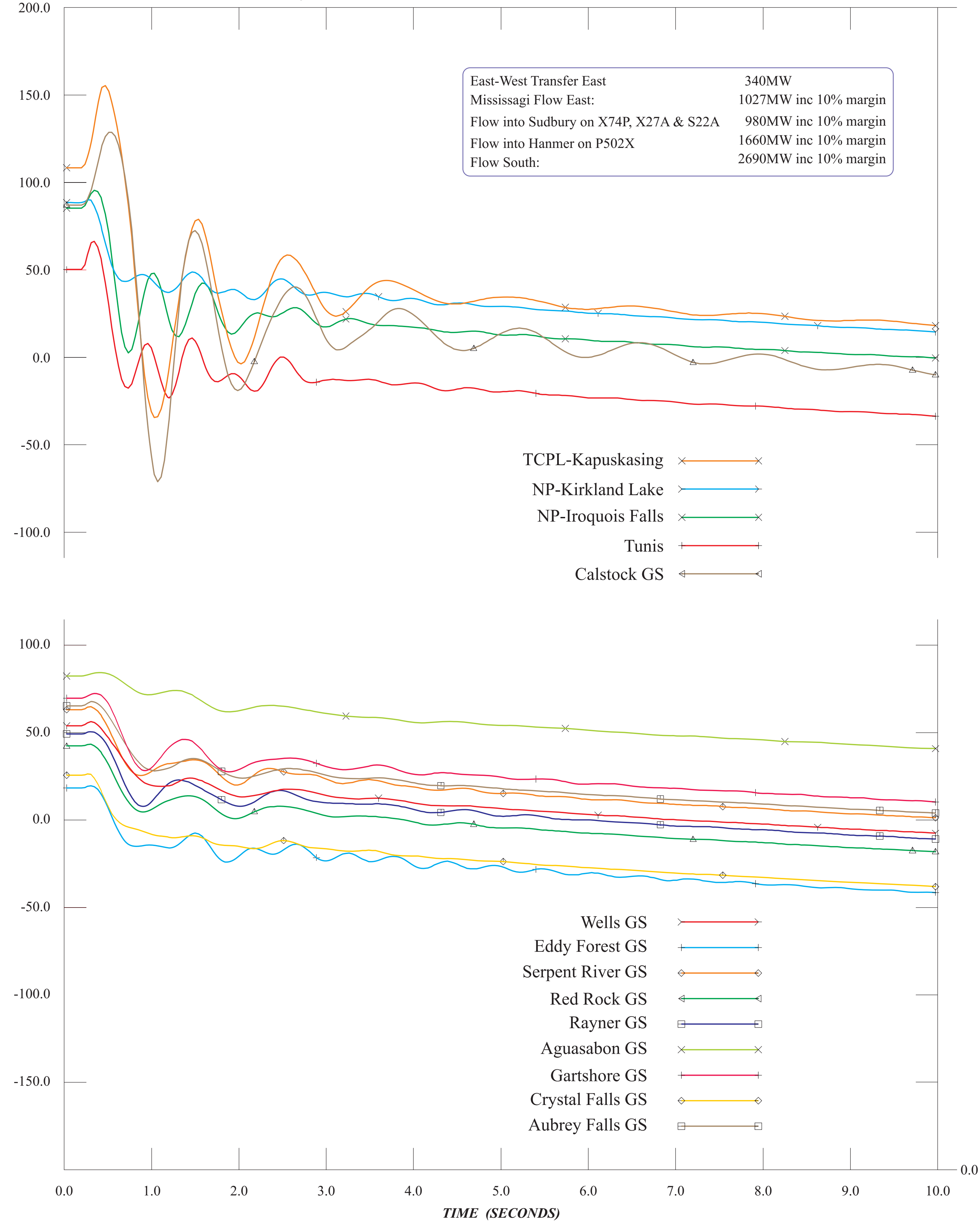


Apparent Impedance Loci for 115kV Circuit A8K

For a 500kV 3-phase fault on circuit P502X at Hanmer TS

DIAGRAM 20

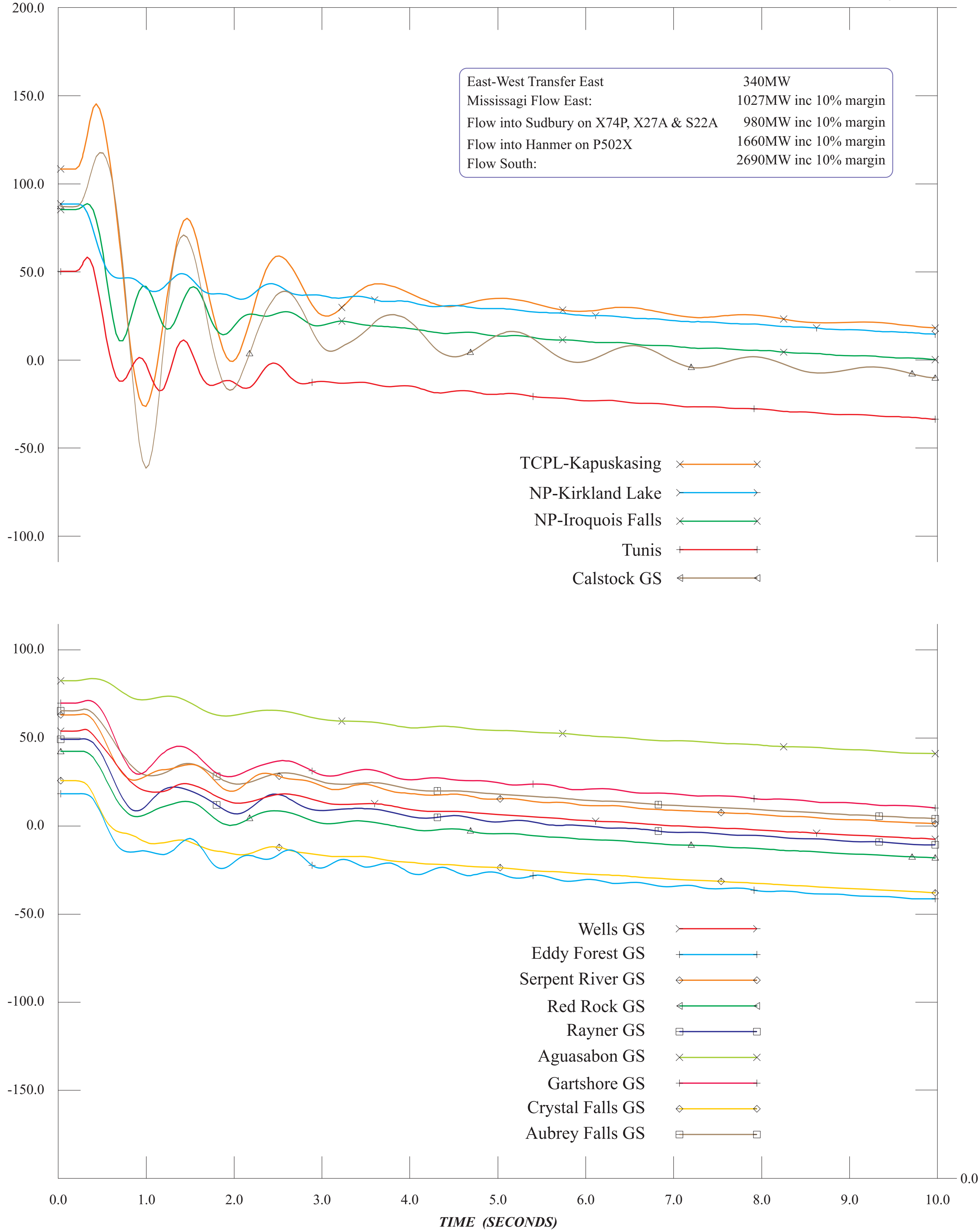
20th December 2006



Generator Rotor Angle Responses to a 3-Phase fault on circuit D501P at Porcupine TS

DIAGRAM 21

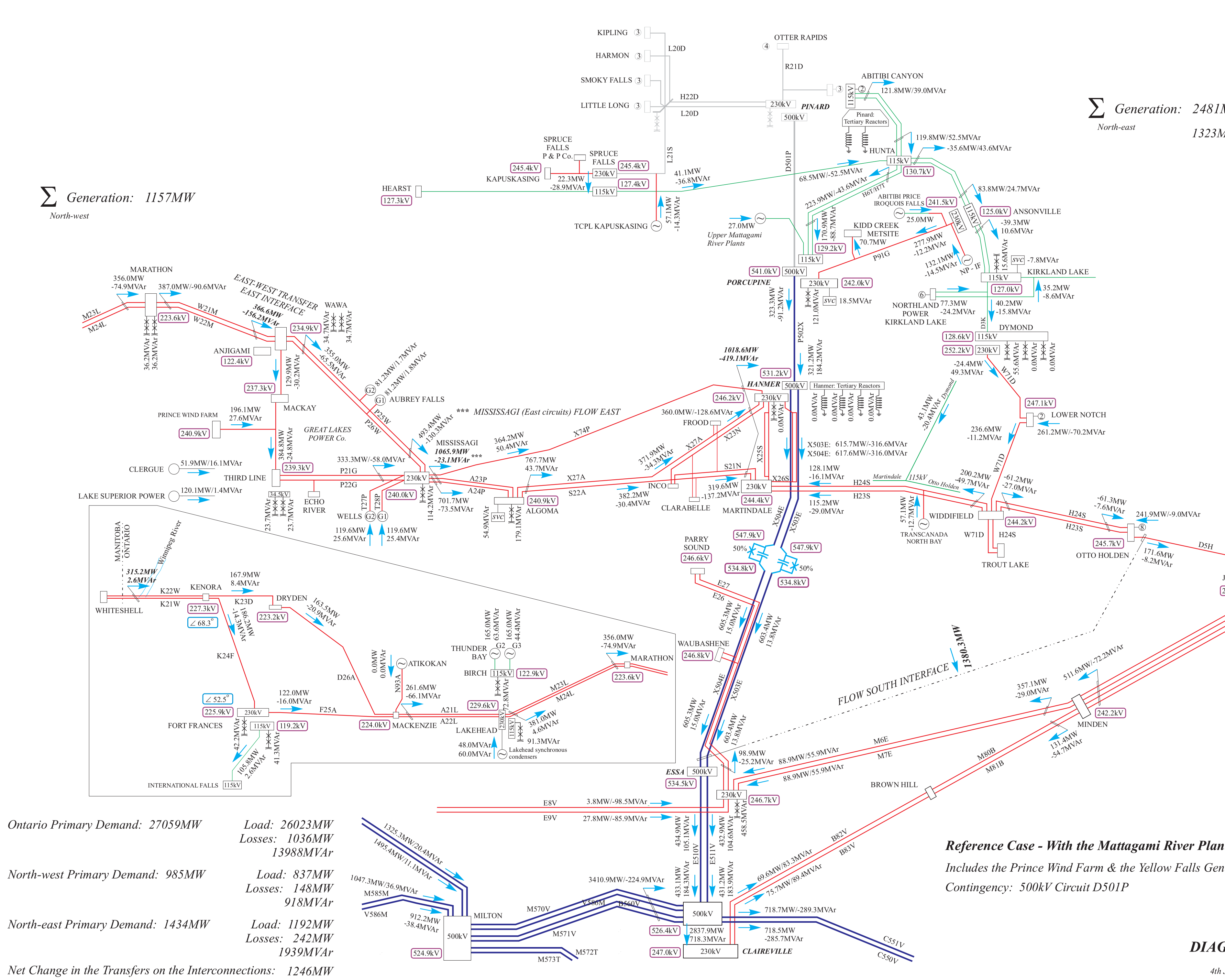
17th July 2006

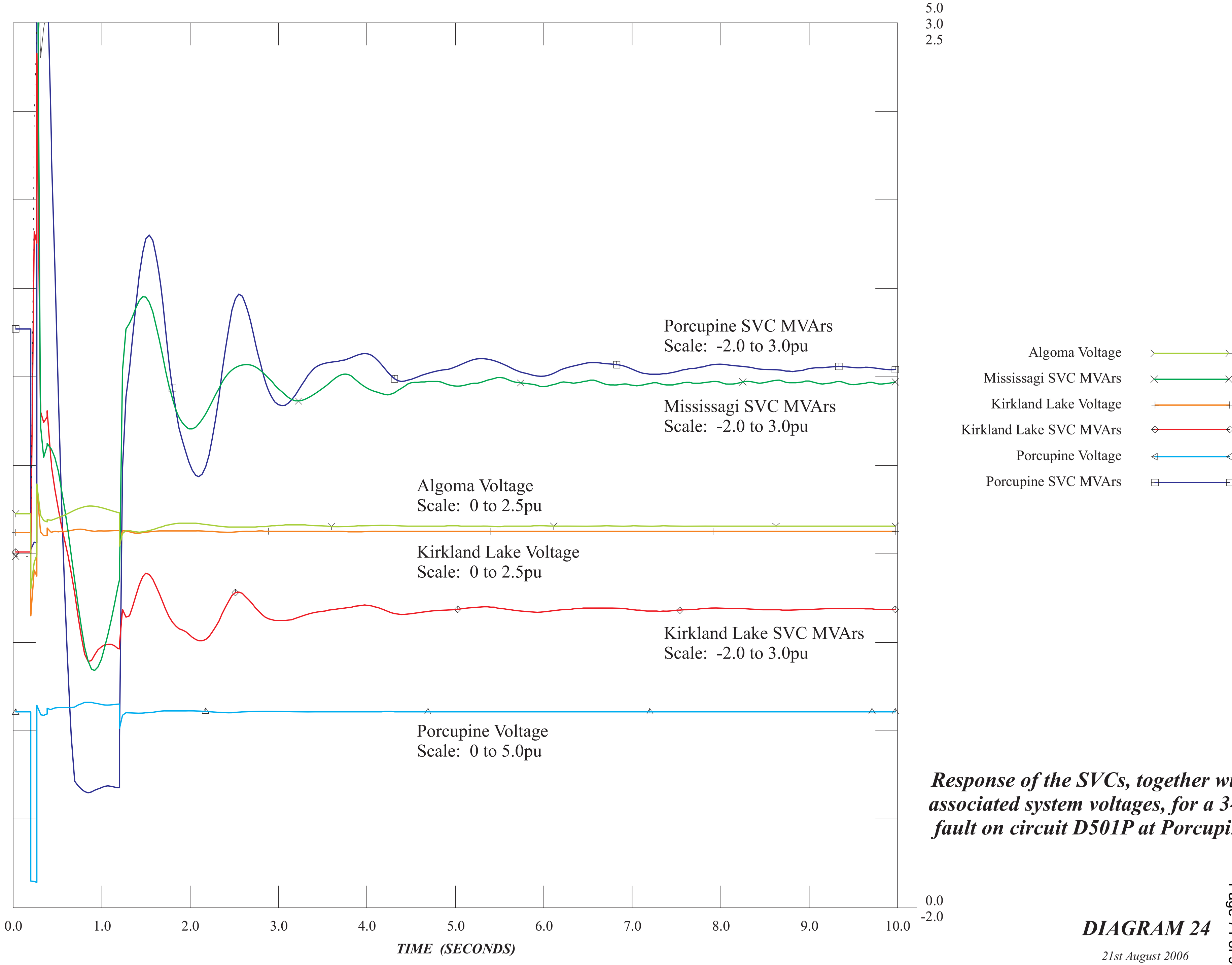


Generator Rotor Angle Responses to a 3-Phase fault on circuit D501P at Pinard TS

DIAGRAM 22

23rd August 2006


Σ Generation: 2481MW
North-east
1323MW REJECTED
Σ Generation: 1157MW
North-west
EAST-WEST TRANSFER
EAST INTERFACE
366.6MW
-156.2MVAr
*** MISSISSAGI (East circuits) FLOW EAST
MISSISSAGI
1065.9MW
-23.1MVAr ***
HANMER
1018.6MW
-419.1MVAr
PORCUPINE
PINARD
FLOW SOUTH INTERFACE
1380.3MW
ESSA
CLAIREVILLE
MILTON
MINDEN
DES JOACHIMS
OTTO HOLDEN
WIDDIFIELD
MARTINDALE
ALGOMA
MACKENZIE
LAKEHEAD
KENORA
FORT FRANCES
WHITESHELL
MANITOBA
ONTARIO
Ontario Primary Demand: 27059MW
Load: 26023MW
Losses: 1036MW
13988MVAr
North-west Primary Demand: 985MW
Load: 837MW
Losses: 148MW
918MVAr
North-east Primary Demand: 1434MW
Load: 1192MW
Losses: 242MW
1939MVAr
Net Change in the Transfers on the Interconnections: 1246MW
Reference Case - With the Mattagami River Plants Expanded
Includes the Prince Wind Farm & the Yellow Falls Generating Station
Contingency: 500kV Circuit D501P
DIAGRAM 23
4th July 2006



Response of the SVCs, together with the associated system voltages, for a 3-phase fault on circuit D501P at Porcupine TS

DIAGRAM 24

21st August 2006

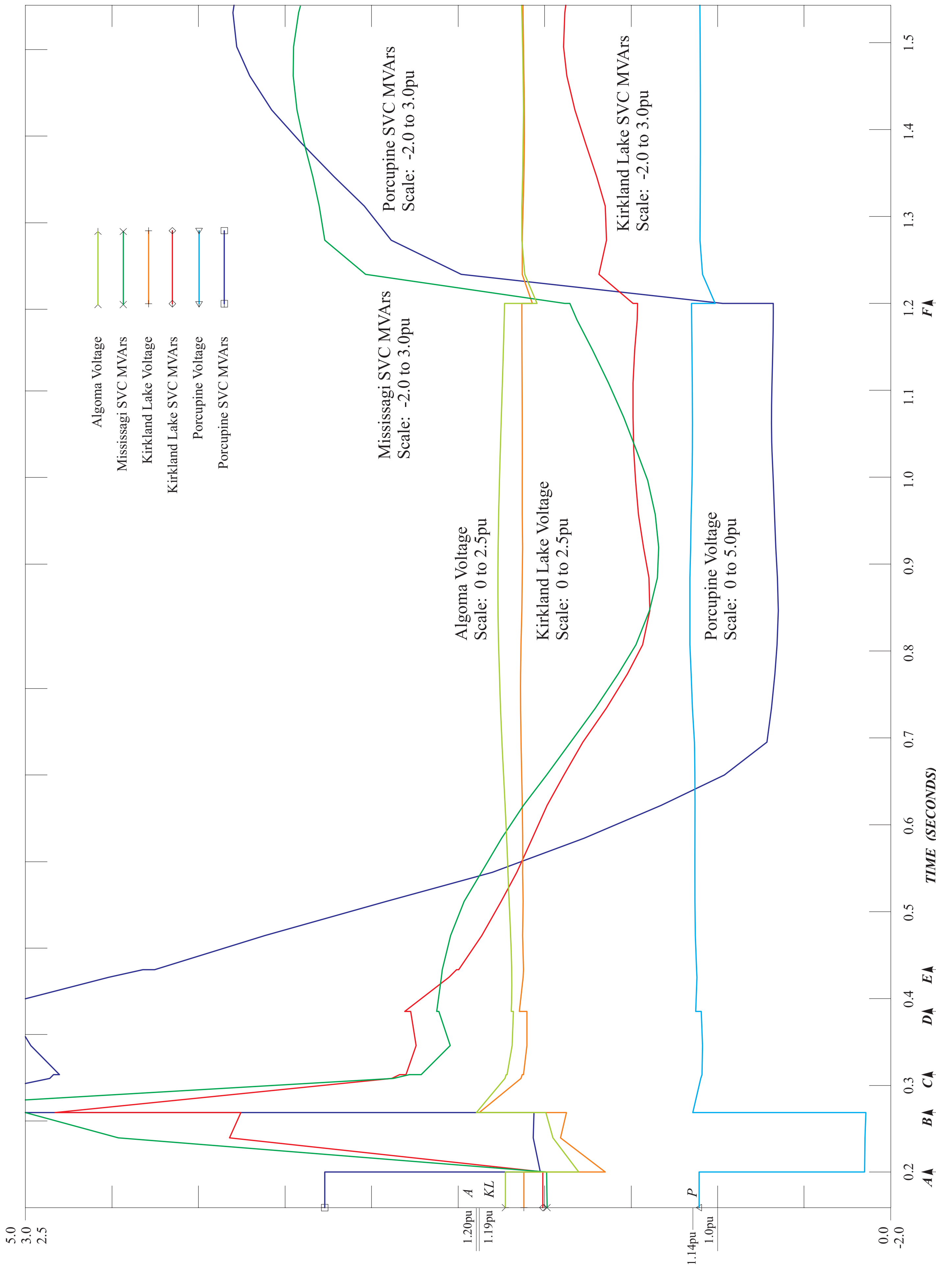
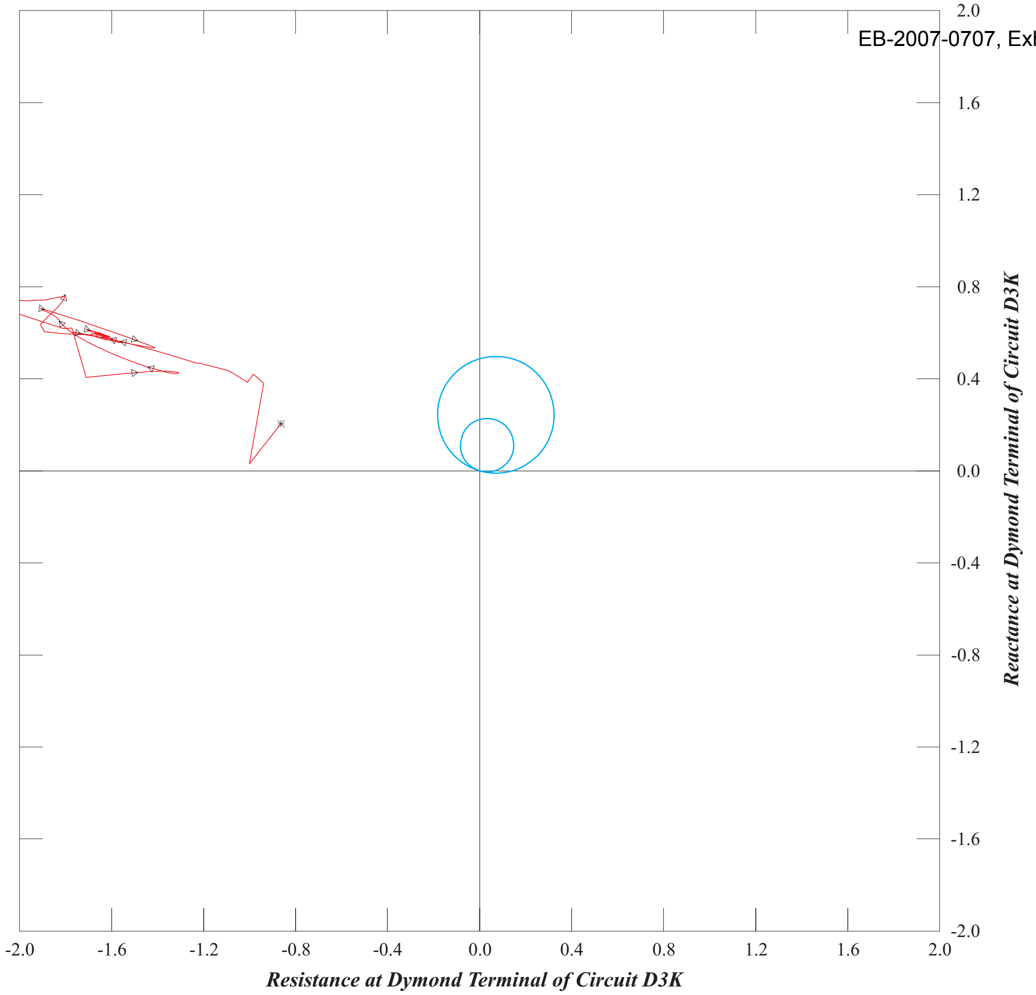
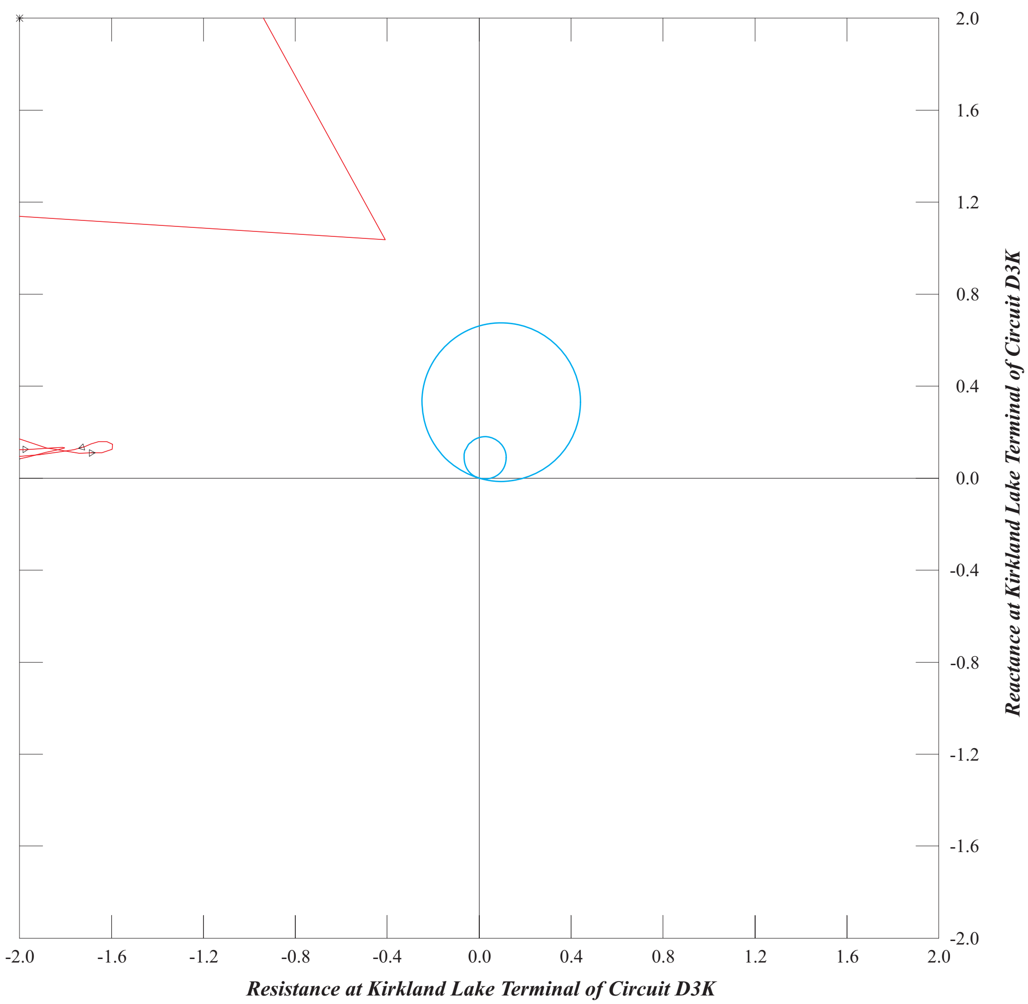


DIAGRAM 25

21st August 2006

SVC responses to a D501P contingency on an expanded time scale



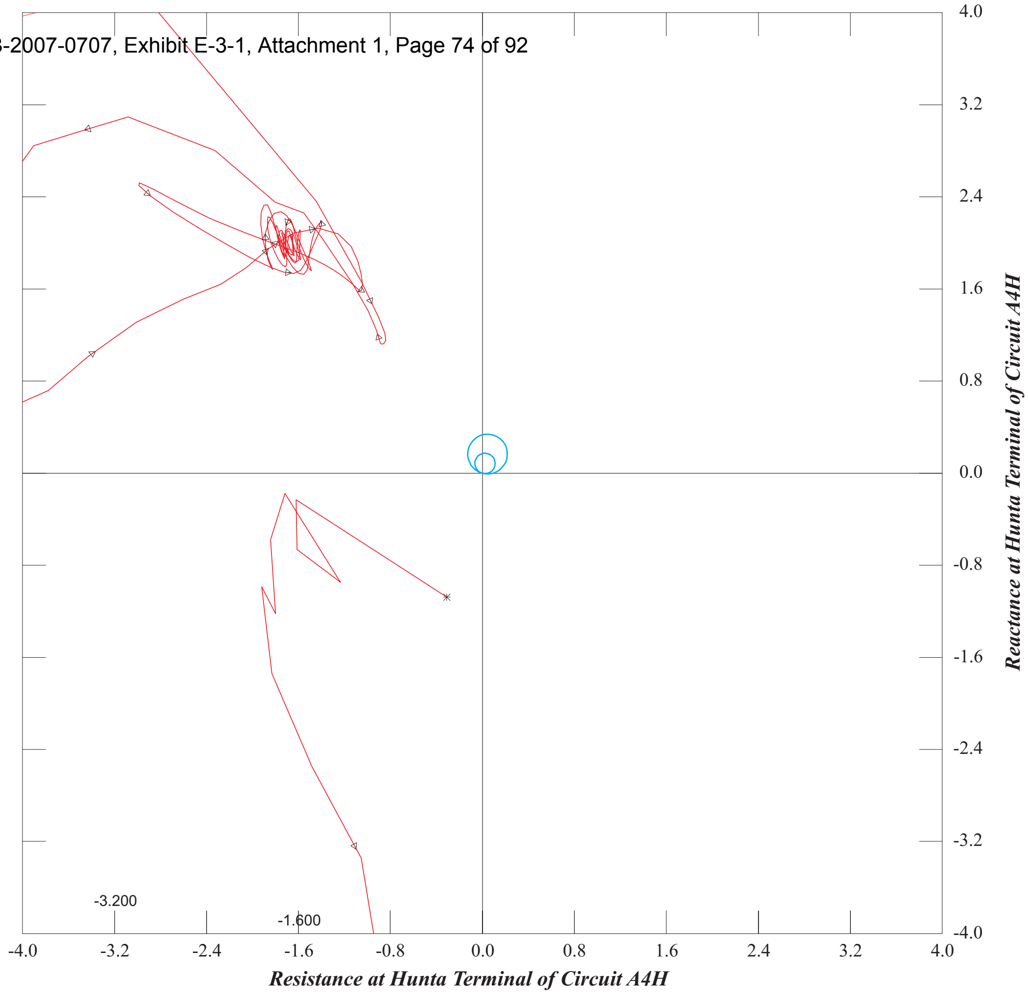


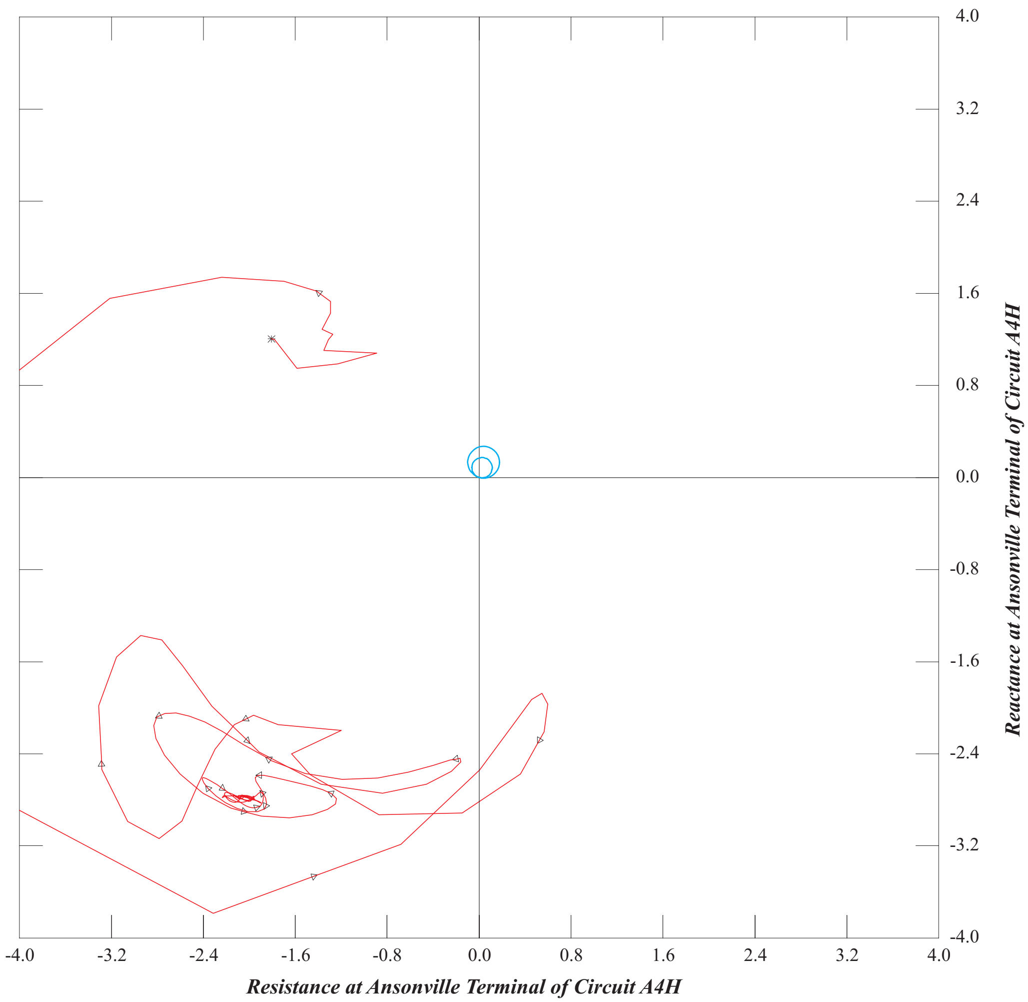
Apparent Impedance Loci
for 115kV circuit D3K

For a 500kV 3-phase fault on circuit D501P at Pinard TS

DIAGRAM 26

20th December 2006



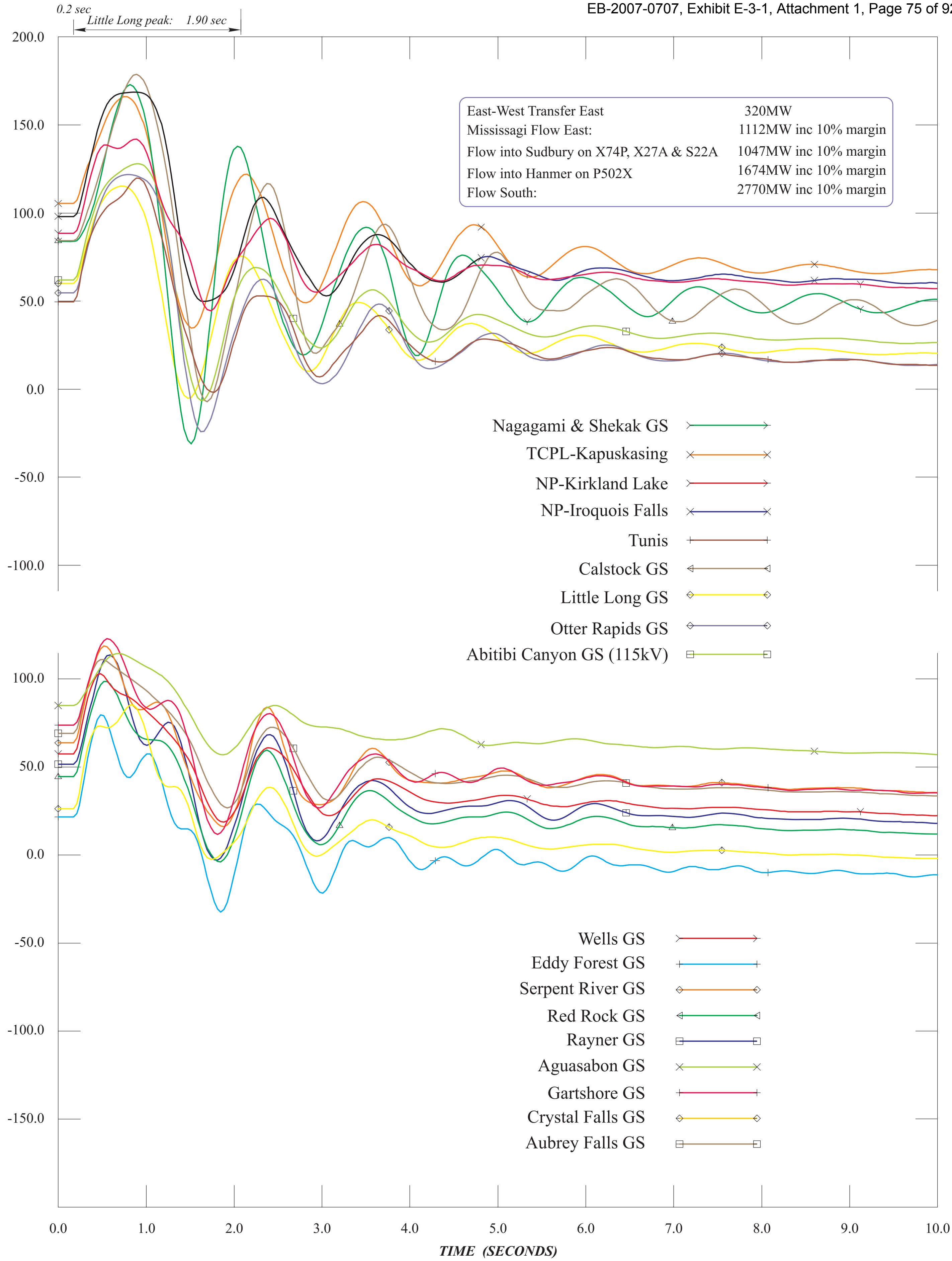


Apparent Impedance Loci for 115kV circuit A4H

For a 500kV 3-phase fault on circuit D501P at Porcupine TS

DIAGRAM 27

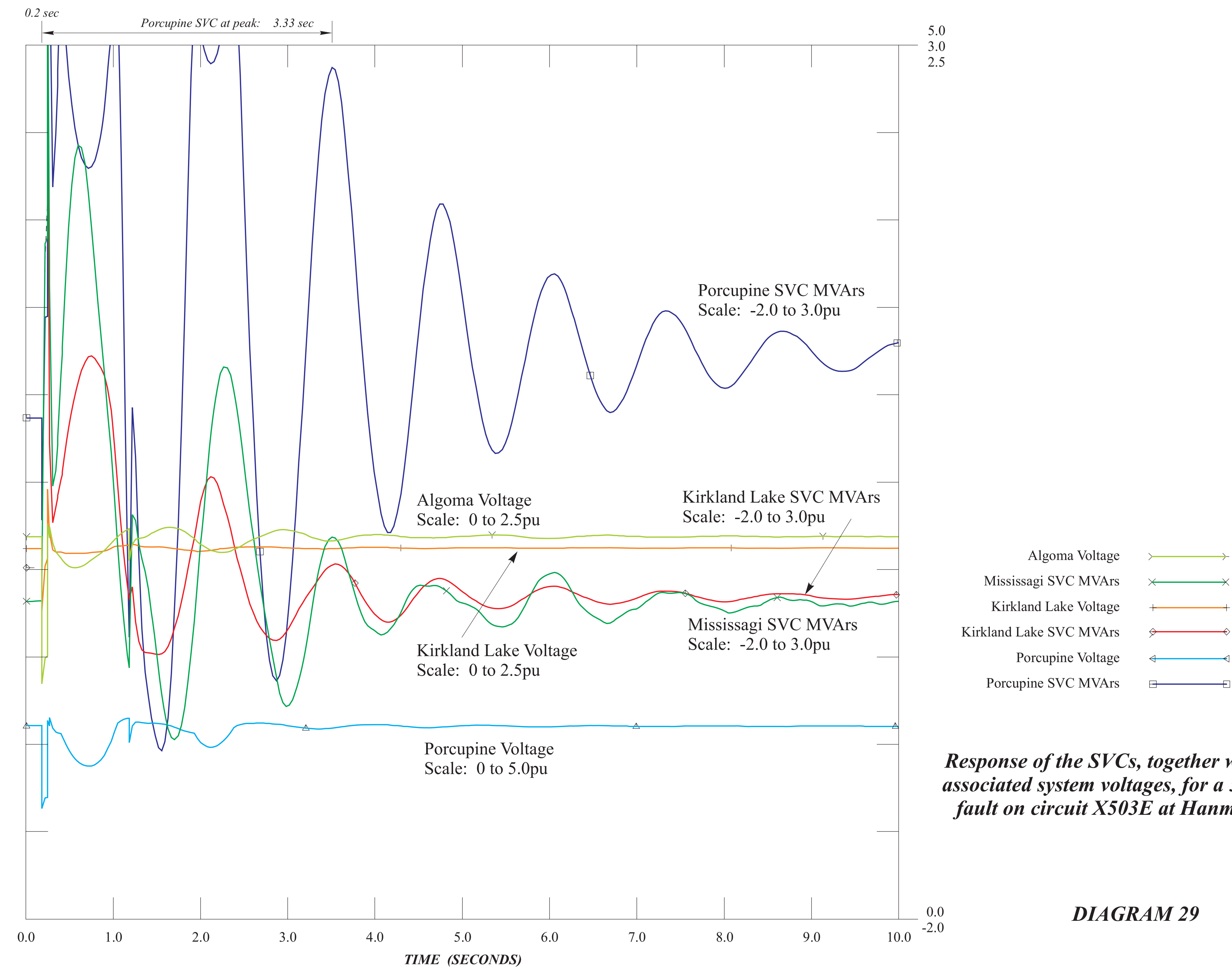
20th December 2006



Generator Rotor Angle Responses to a 3-Phase fault on circuit X503E at Hanmer TS

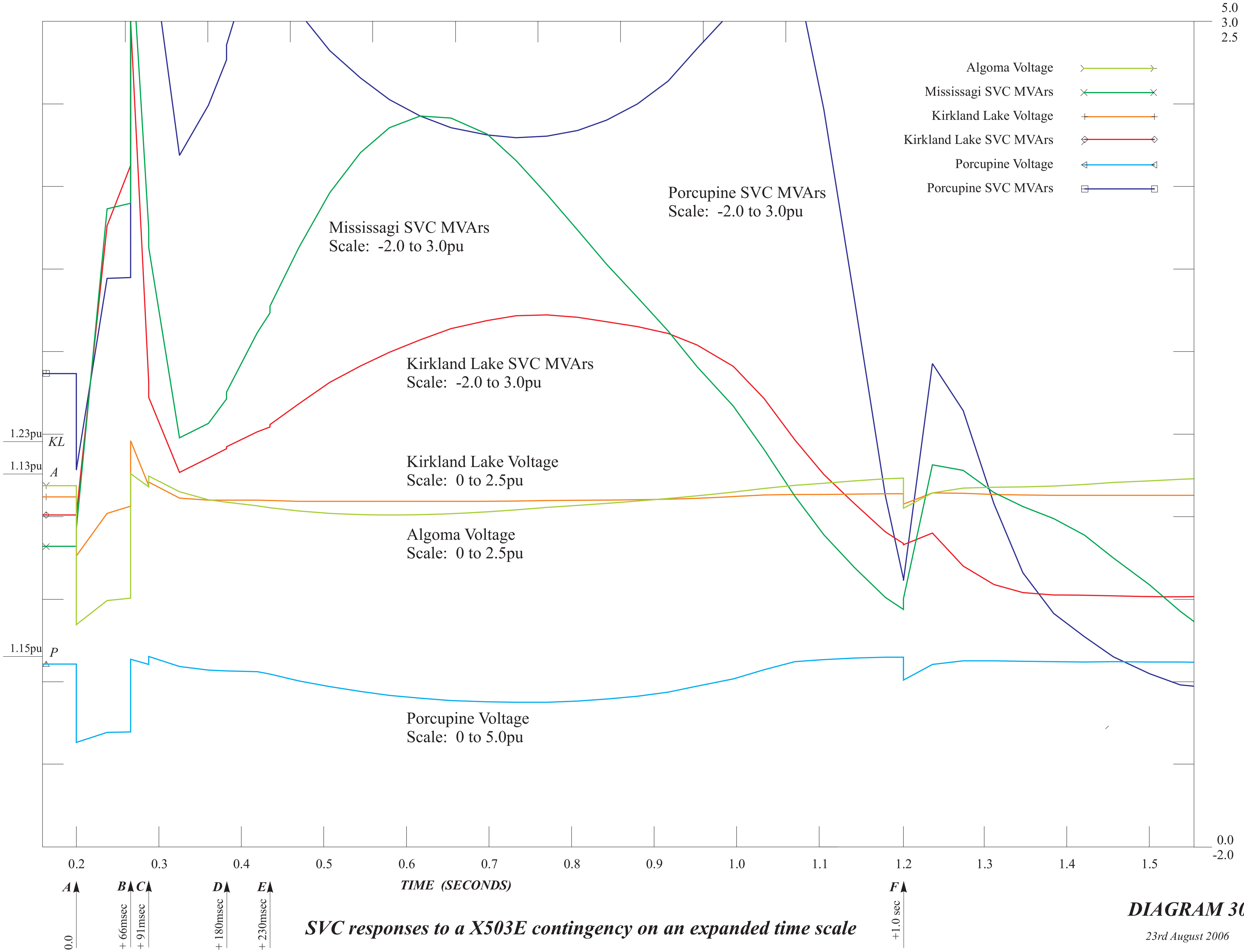
DIAGRAM 28

23rd August 2006



Response of the SVCs, together with the associated system voltages, for a 3-phase fault on circuit X503E at Hanmer TS

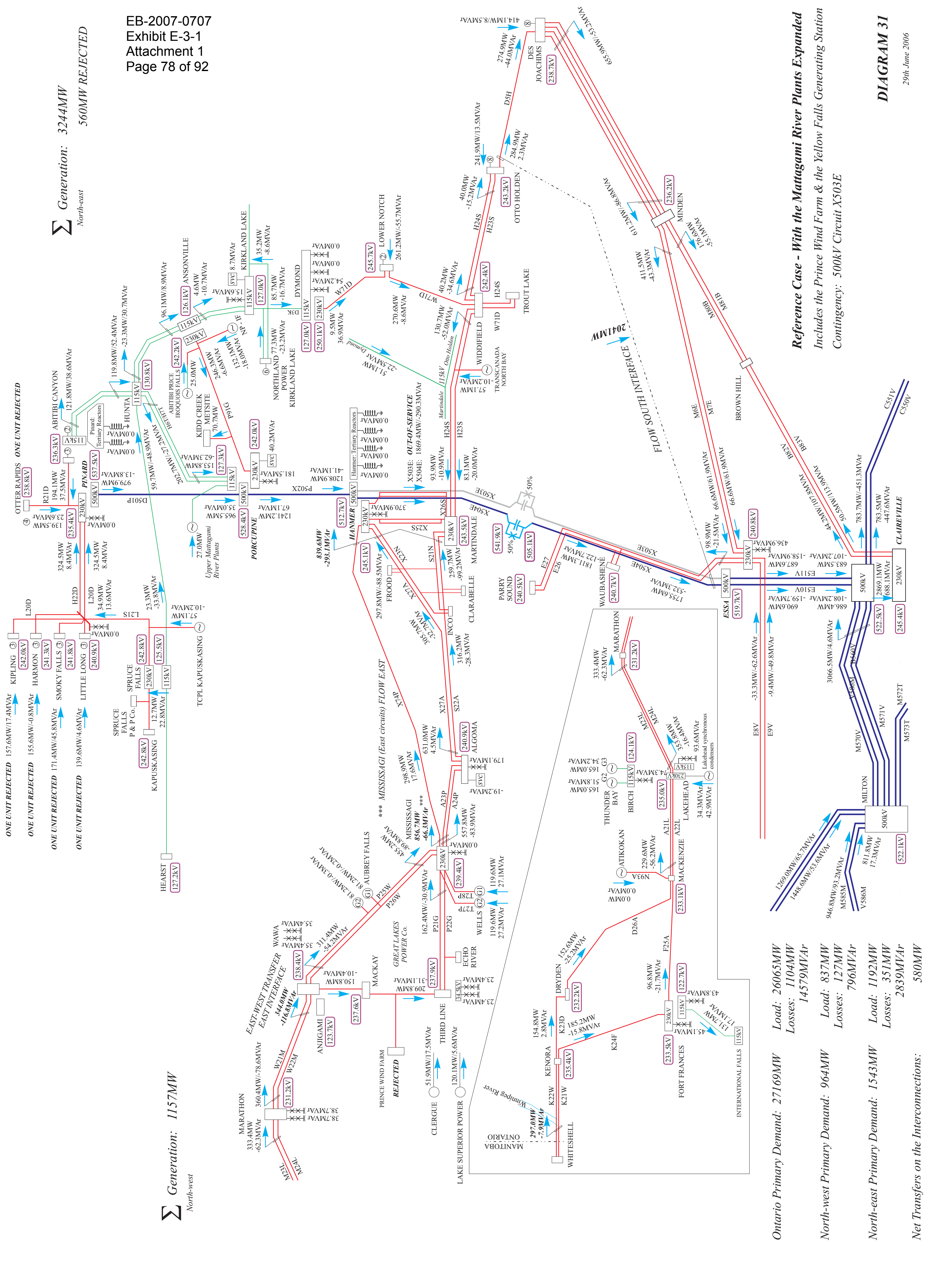
DIAGRAM 29



SVC responses to a X503E contingency on an expanded time scale

DIAGRAM 30

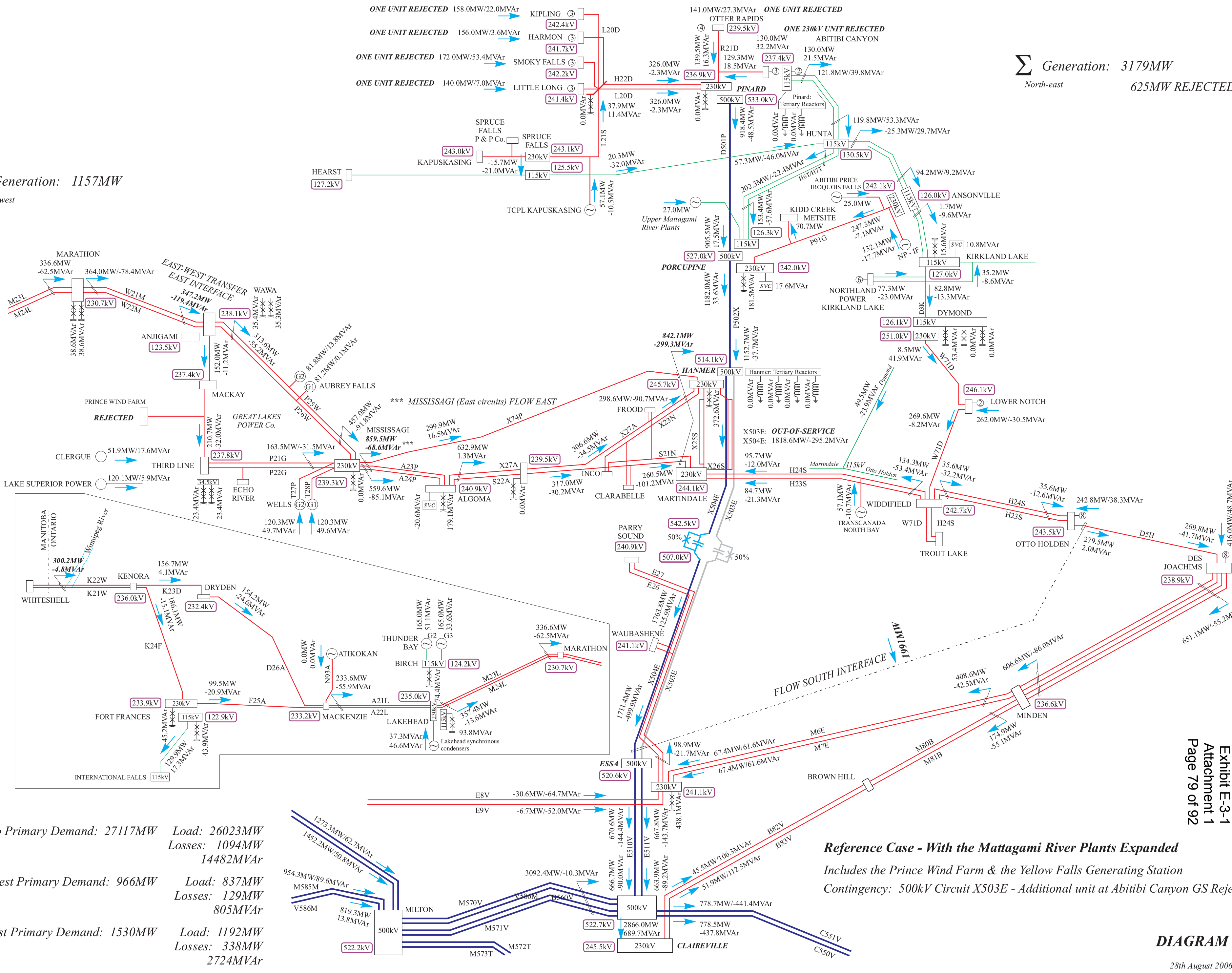
23rd August 2006


Reference Case - With the Mattagami River Plants Expanded
Includes the Prince Wind Farm & the Yellow Falls Generating Station
Contingency: 500kV Circuit X503E
DIAGRAM 31
29th June 2006
Σ Generation: 3244MW
North-east
560MW REJECTED
Σ Generation: 1157MW
North-west
FLOW SOUTH INTERFACE
2041MW
EAST-WEST TRANSFER
EAST INTERFACE
MISSISSAGI (East circuits) FLOW EAST
Ontario Primary Demand: 27169MW
Load: 26065MW
Losses: 1104MW
14579MVAr
North-west Primary Demand: 964MW
Load: 837MW
Losses: 127MW
796MVAr
North-east Primary Demand: 1543MW
Load: 1192MW
Losses: 351MW
2839MVAr
Net Transfers on the Interconnections: 580MW

Reference Case - With the Mattagami River Plants Expanded

Includes the Prince Wind Farm & the Yellow Falls Generating Station

Contingency: 500kV Circuit X503E - Additional unit at Abitibi Canyon GS Rejected



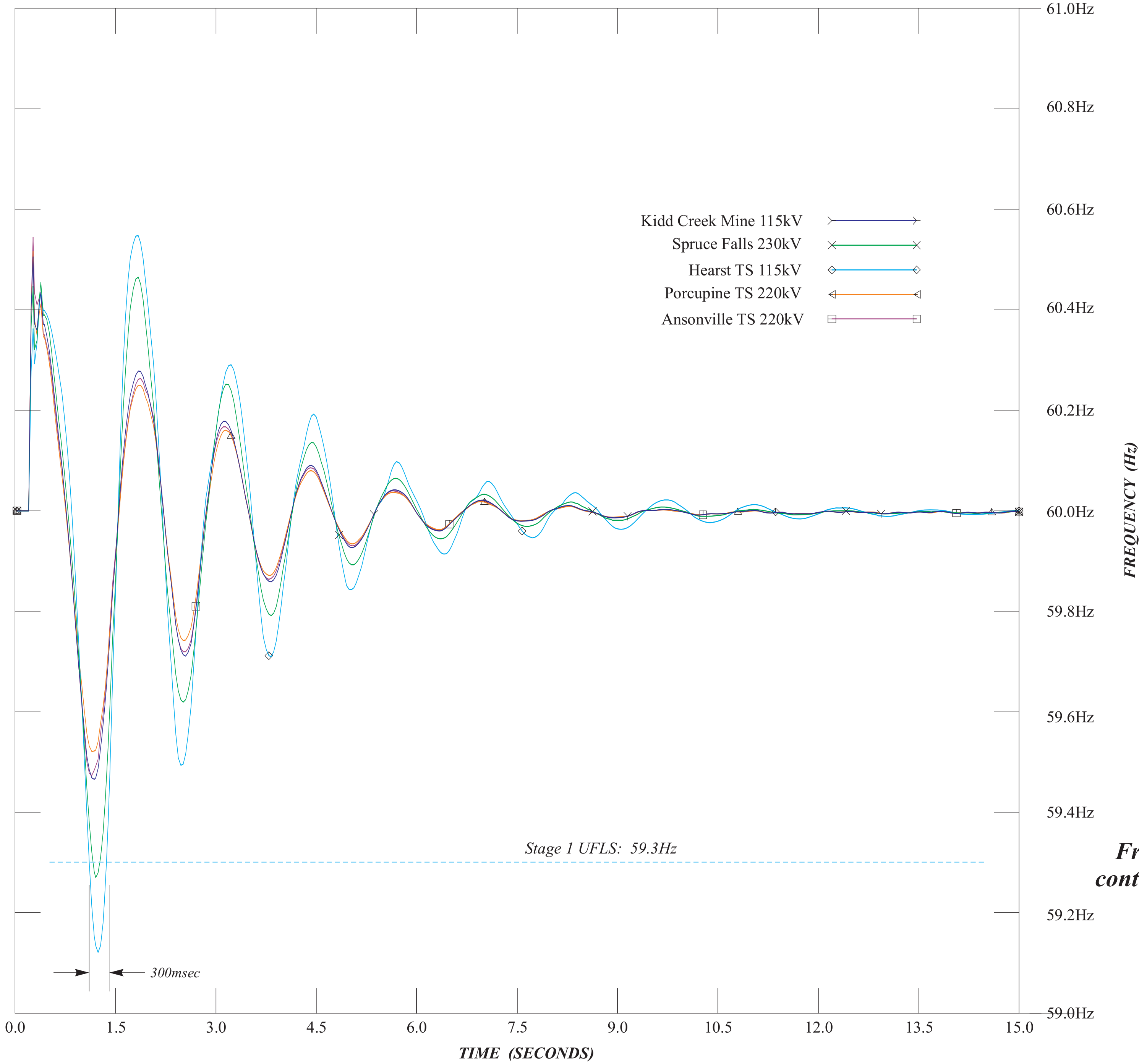
Ontario Primary Demand: 27117MW   Load: 26023MW
Losses: 1094MW
14482MVAr

North-west Primary Demand: 966MW   Load: 837MW
Losses: 129MW
805MVAr

North-east Primary Demand: 1530MW   Load: 1192MW
Losses: 338MW
2724MVAr

DIAGRAM 32

28th August 2006



Frequency Response following a contingency involving circuit X503E

DIAGRAM 33

7th September 2006

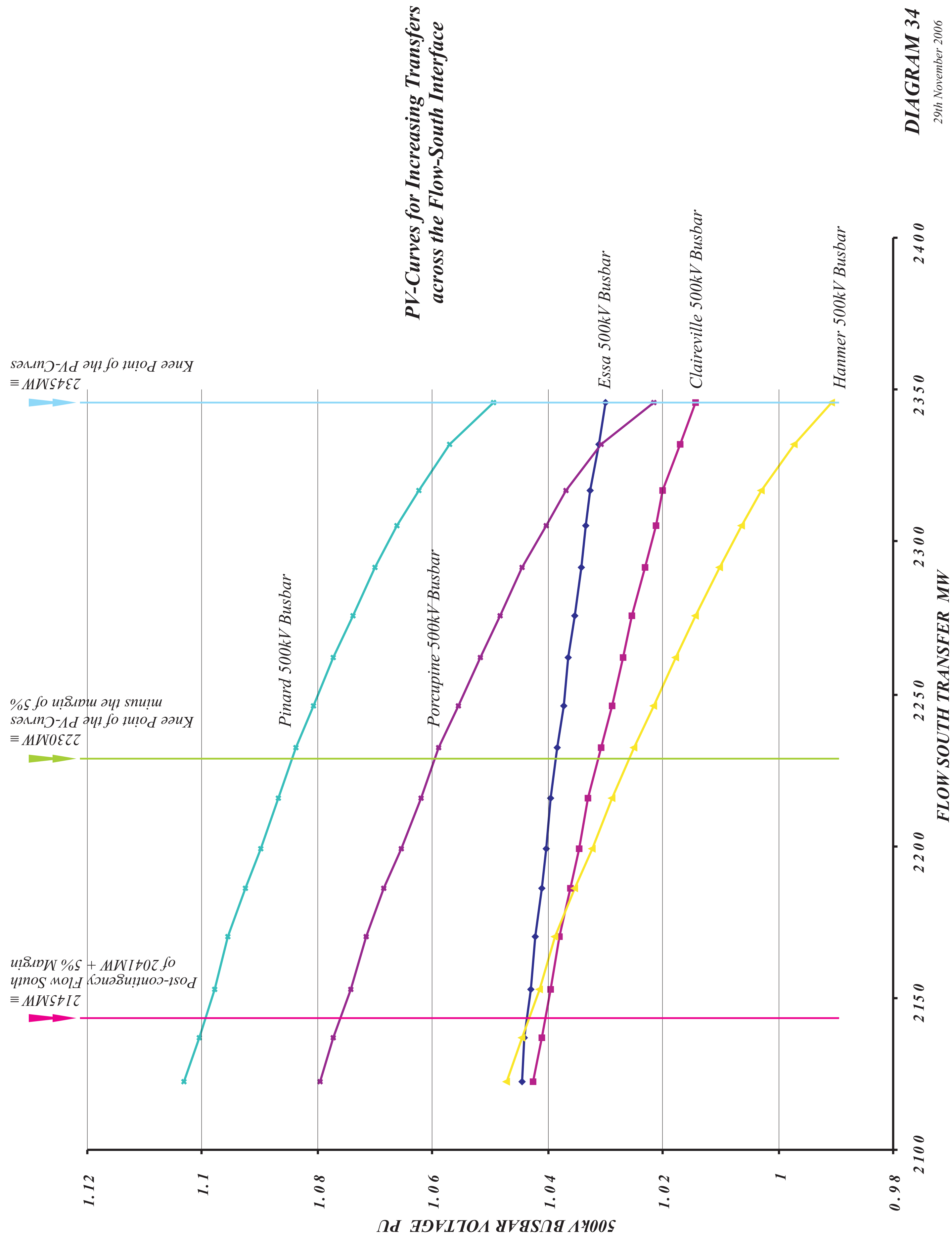
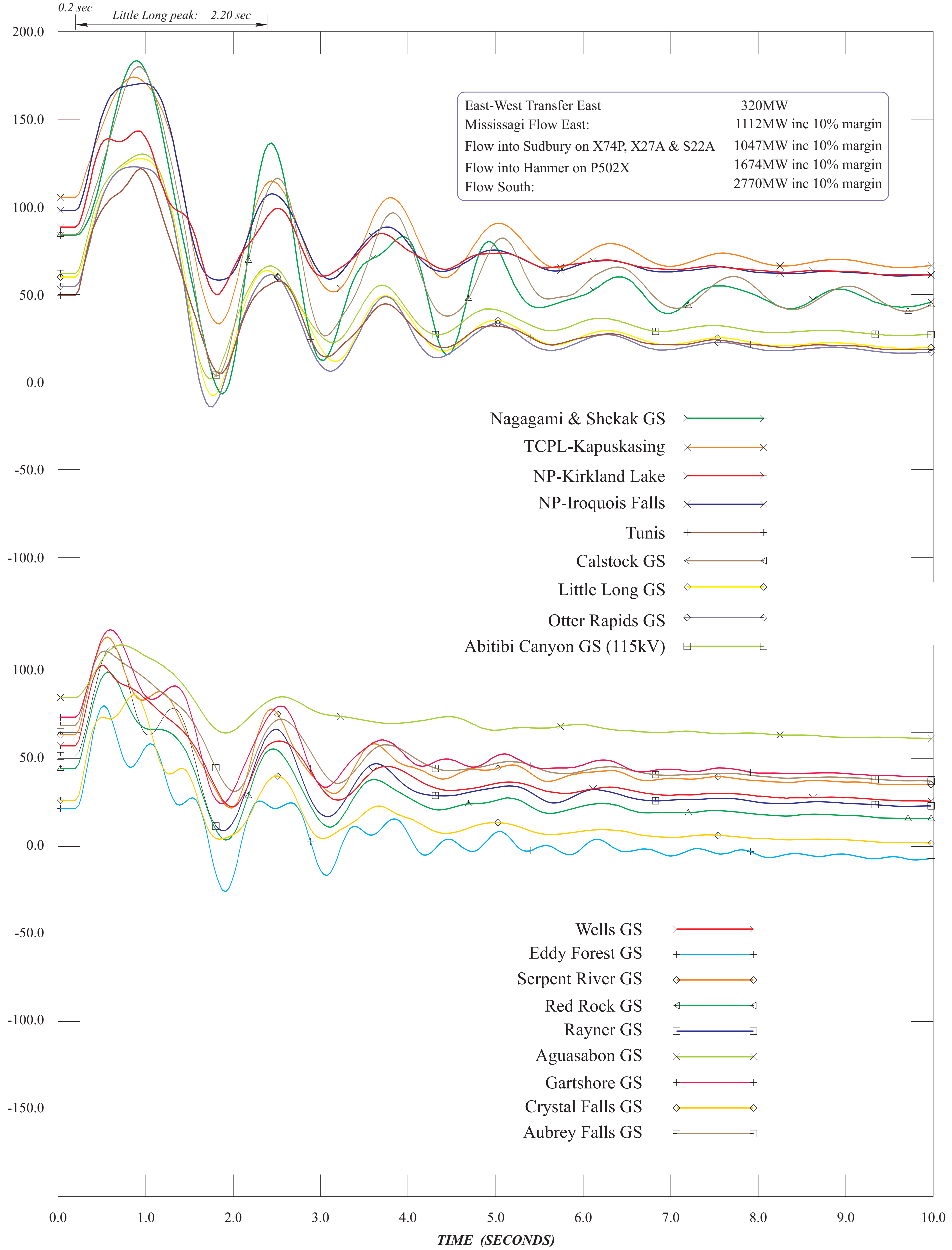


DIAGRAM 34
29th November 2006
PV-Curves for Increasing Transfers across the Flow-South Interface
Pinard 500kV Busbar
Porcupine 500kV Busbar
Essa 500kV Busbar
Claireville 500kV Busbar
Hanmer 500kV Busbar
2145MW ≡ Post-contingency Flow South of 2041MW + 5% Margin
2230MW ≡ Knee Point of the PV-Curves minus the margin of 5%
2345MW ≡ Knee Point of the PV-Curves
500kV BUSBAR VOLTAGE PU
1.12
1.1
1.08
1.06
1.04
1.02
1
0.98
FLOW SOUTH TRANSFER MW
2100
2150
2200
2250
2300
2350
2400

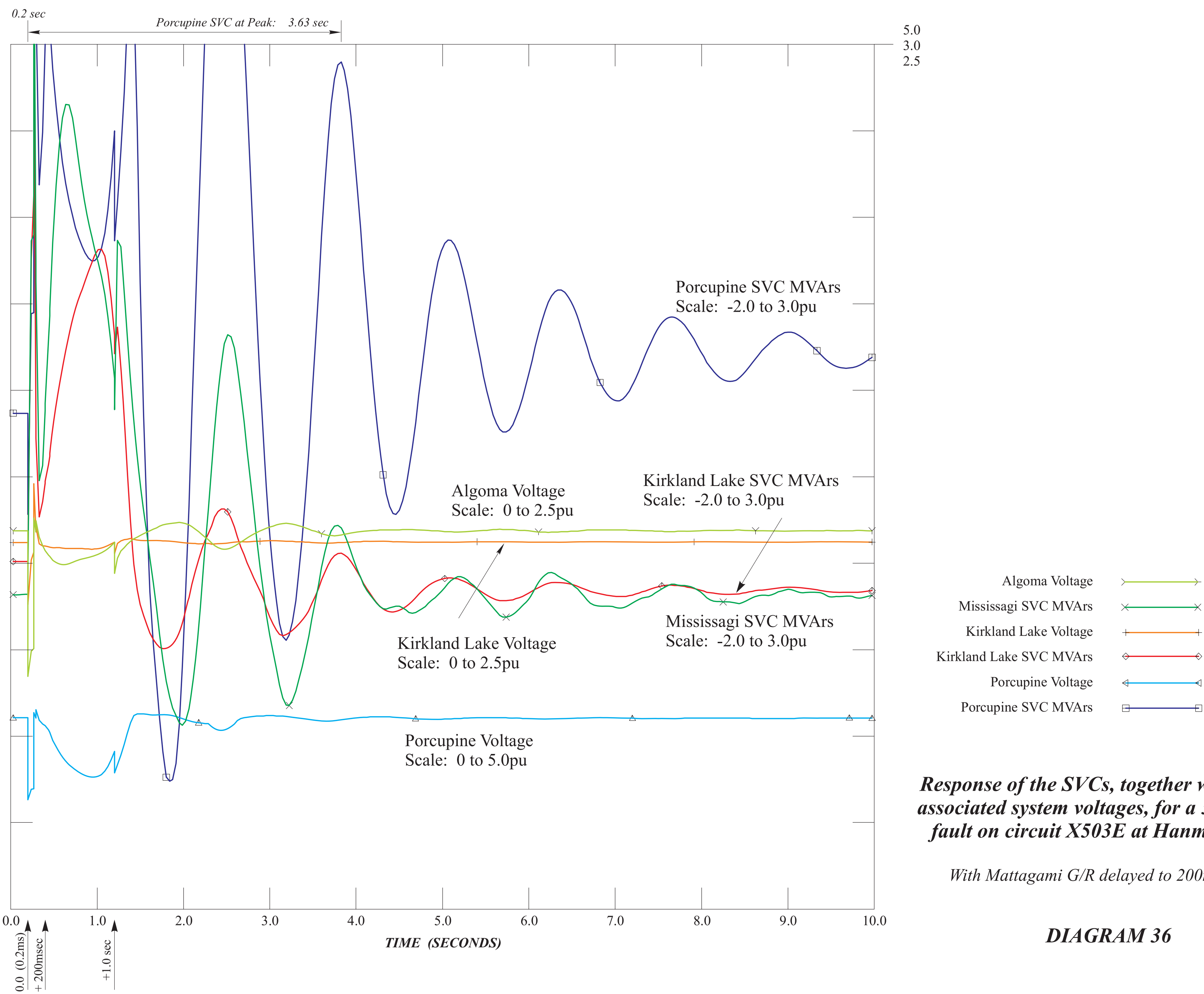


Generator Rotor Angle Responses to a 3-Phase fault on circuit X503E at Hanmer TS

(with the rejection time for the generation in the Moose River basin increased to 200msec)

DIAGRAM 35

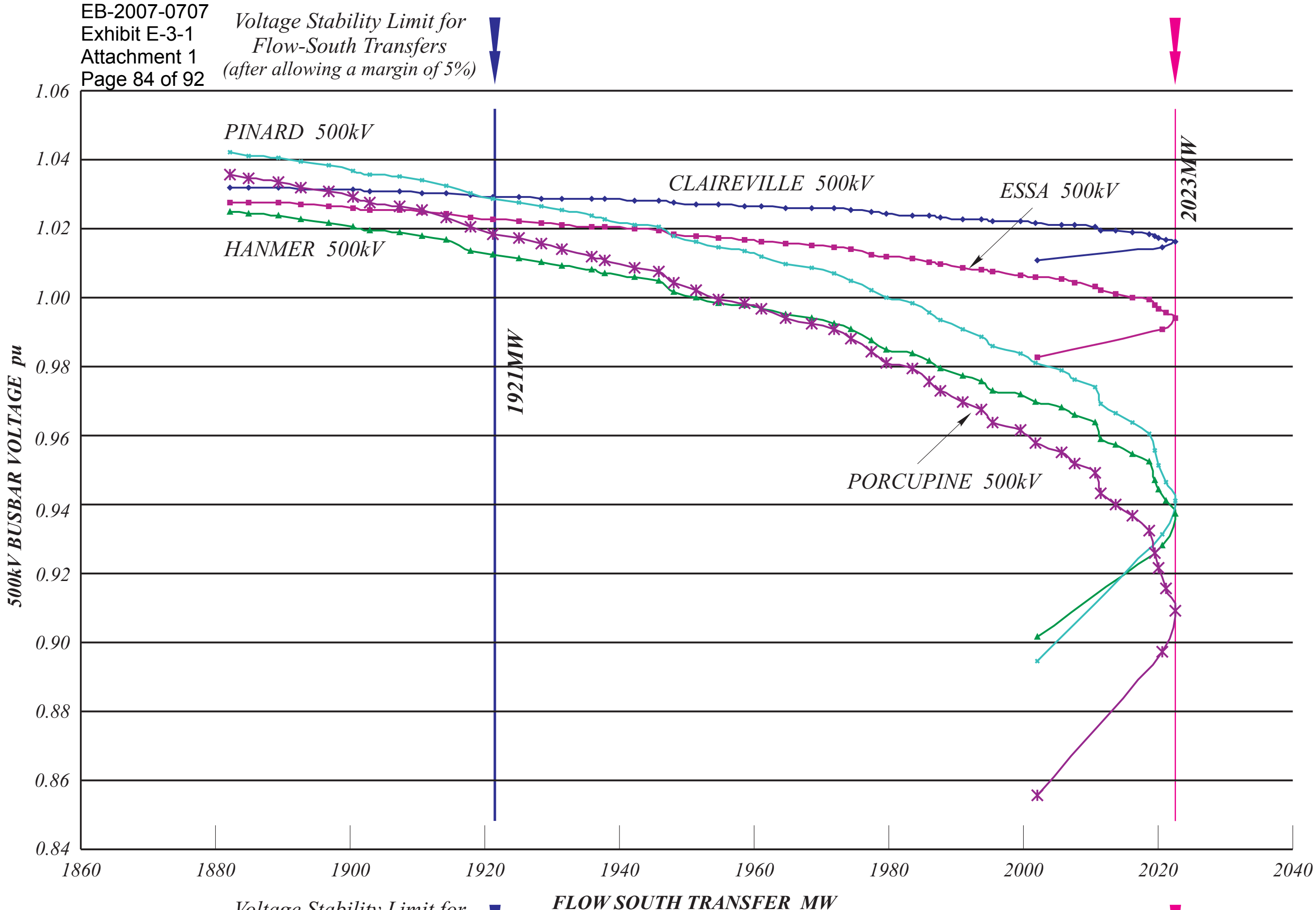
8th January 2007

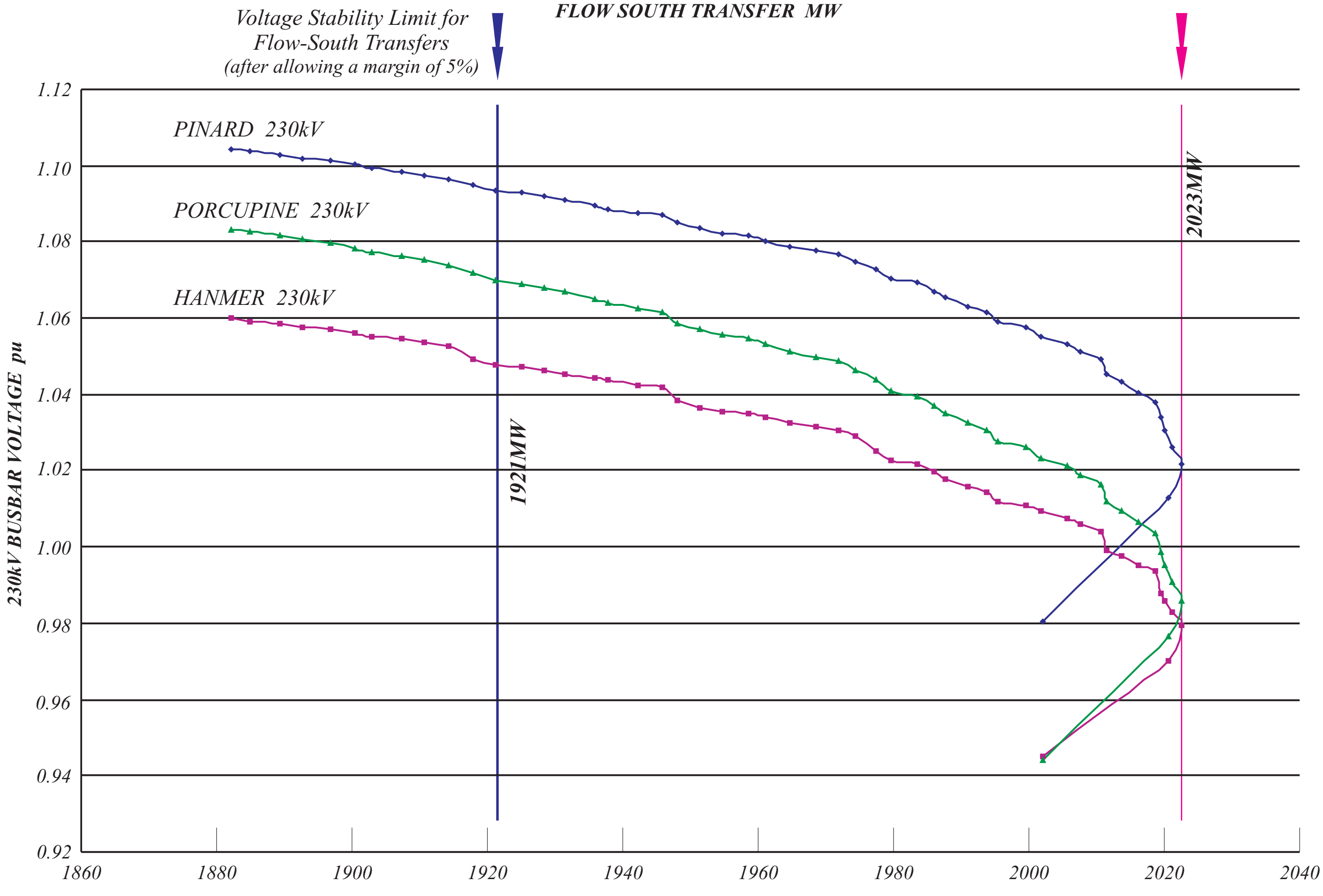


Response of the SVCs, together with the associated system voltages, for a 3-phase fault on circuit X503E at Hanmer TS

With Mattagami G/R delayed to 200msec

DIAGRAM 36

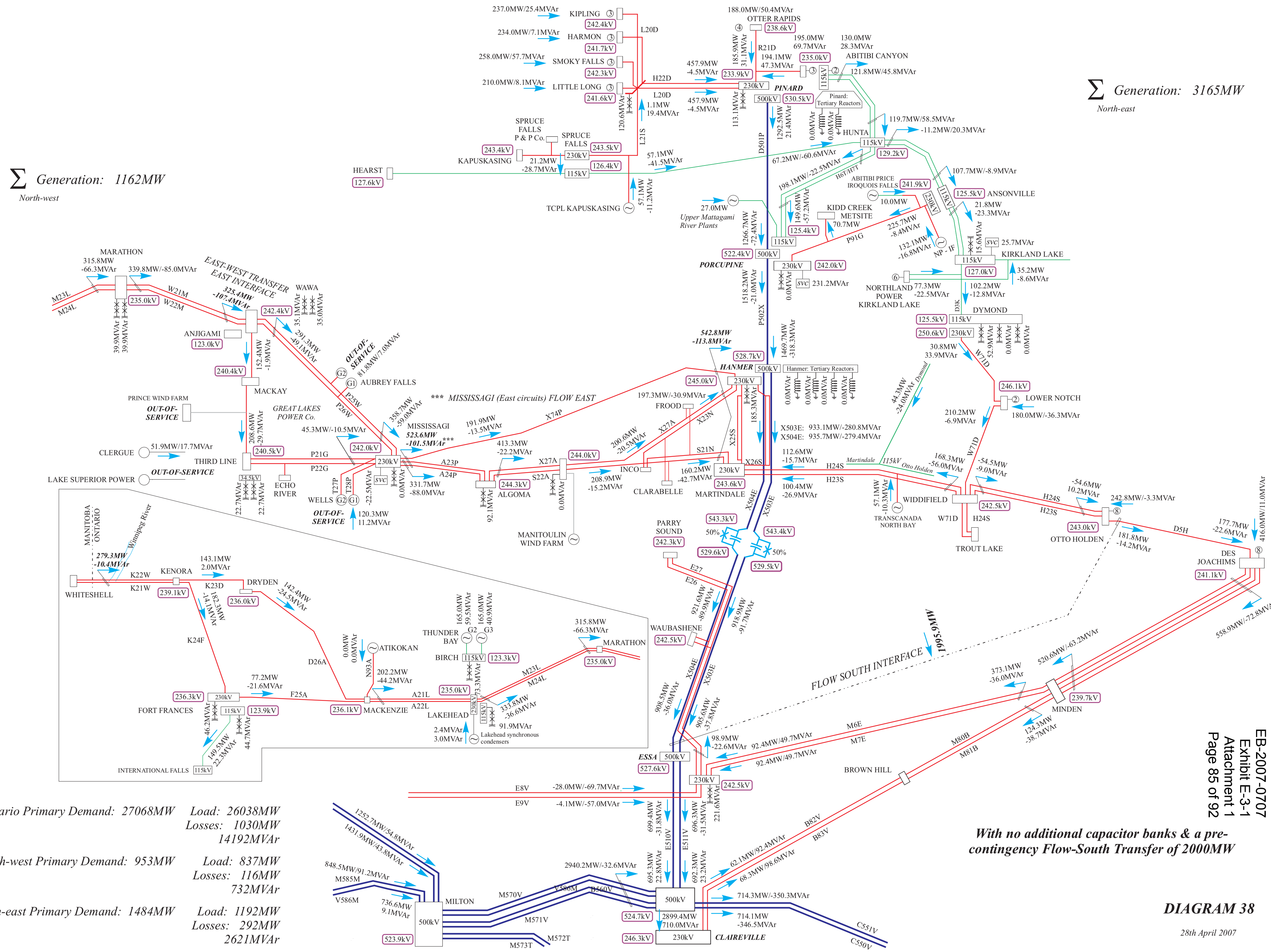




Post-Contingency PV-Curves for Increased Transfers across the Flow-South Interface

DIAGRAM 37

24th April 2007



Ontario Primary Demand: 27068MW Load: 26038MW Losses: 1030MW 14192MVAr

North-west Primary Demand: 953MW Load: 837MW Losses: 116MW 732MVAr

North-east Primary Demand: 1484MW Load: 1192MW Losses: 292MW 2621MVAr

With no additional capacitor banks & a pre-contingency Flow-South Transfer of 2000MW

DIAGRAM 38

28th April 2007

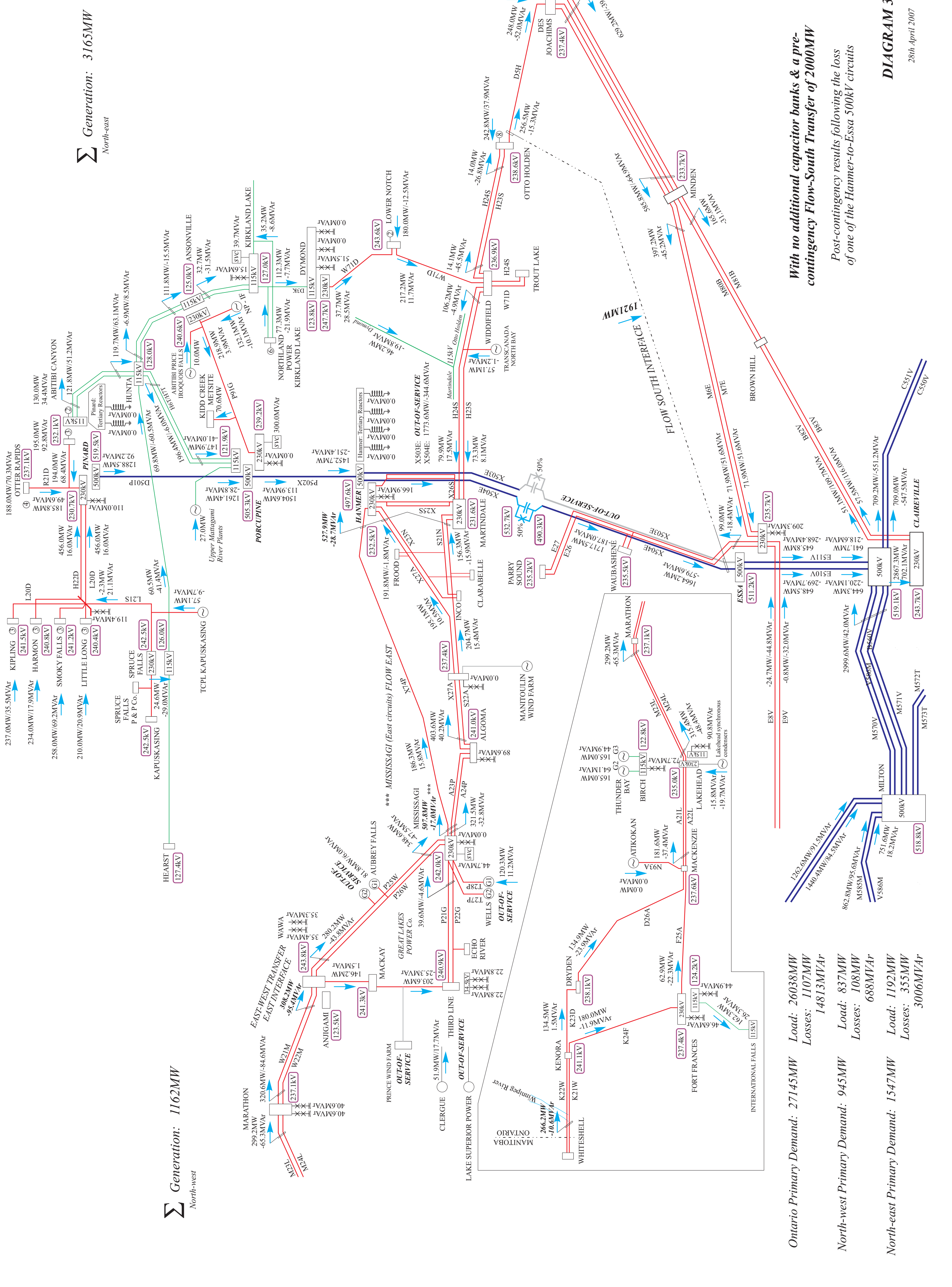
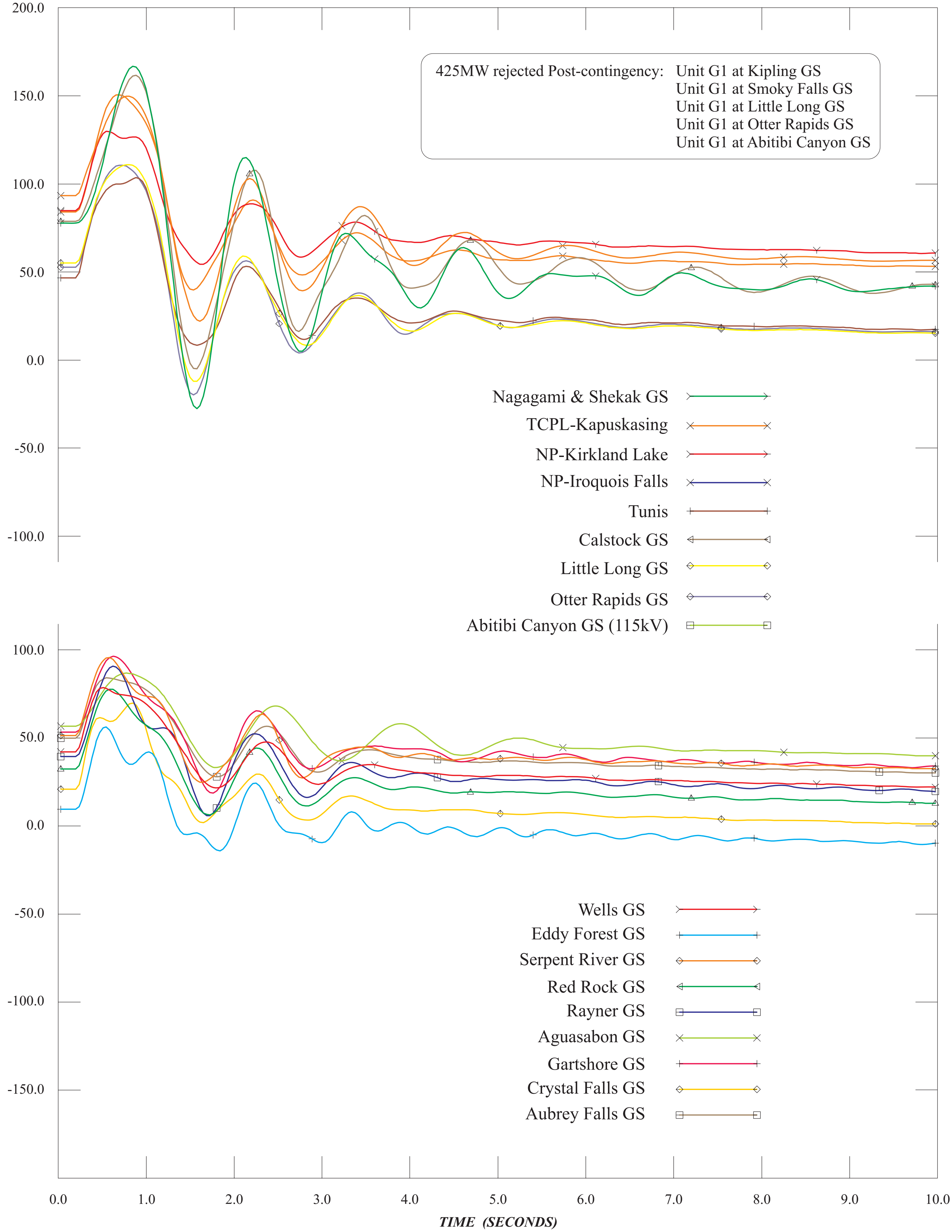


DIAGRAM 39
28th April 2007
With no additional capacitor banks & a pre-contingency Flow-South Transfer of 2000MW
Post-contingency results following the loss of one of the Hanmer-to-Essa 500kV circuits
Σ Generation: 3165MW North-east
Σ Generation: 1162MW North-west
FLOW SOUTH INTERFACE
1921MW
EAST-WEST TRANSFER EAST INTERFACE
308.2MW -95.4MVAr
*** MISSISSAGI (East circuits) FLOW EAST
MISSISSAGI 507.8MW -17.0MVAr ***
OUT-OF-SERVICE
HANMER
PORCUPINE
PINARD
ESSA
CLAIREVILLE
MILTON
DES JOACHIMS
OTTO HOLDEN
MINDEN
WIDDIFIELD
MARTINDALE
ALGOMA
WAWA
MACKAY
THIRD LINE
MARATHON
THUNDER BAY
LAKEHEAD
MACKENZIE
DRYDEN
KENORA
WHITESHELL
FORT FRANCES
MANITOBA
ONTARIO
Ontario Primary Demand: 27145MW
Load: 26038MW
Losses: 1107MW
14813MVAr
North-west Primary Demand: 945MW
Load: 837MW
Losses: 108MW
688MVAr
North-east Primary Demand: 1547MW
Load: 1192MW
Losses: 355MW
3006MVAr

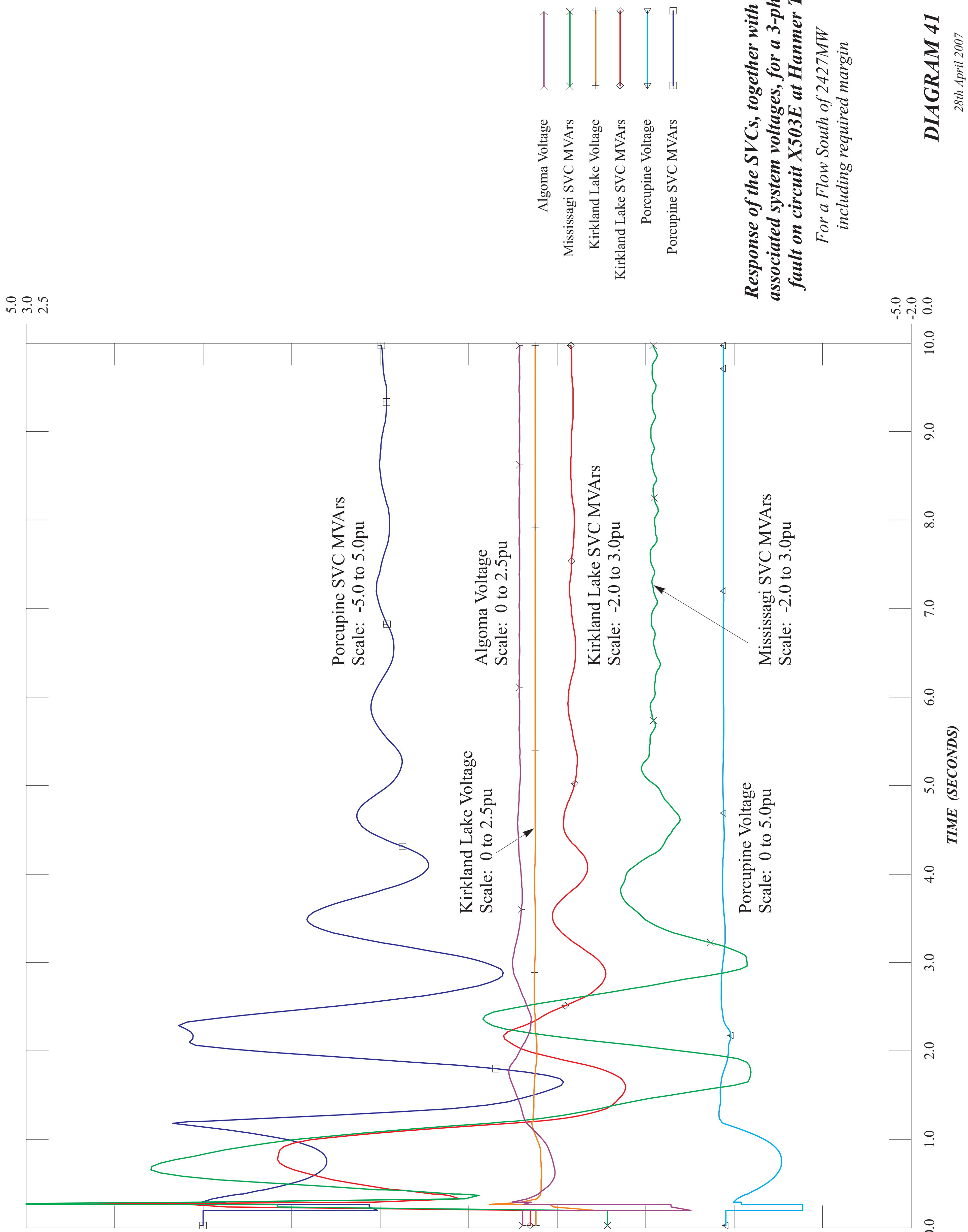


Generator Rotor Angle Responses to a 3-Phase fault on circuit X503E at Hanmer TS

For a Flow South of 2427MW including the required margin

DIAGRAM 40

28th April 2007

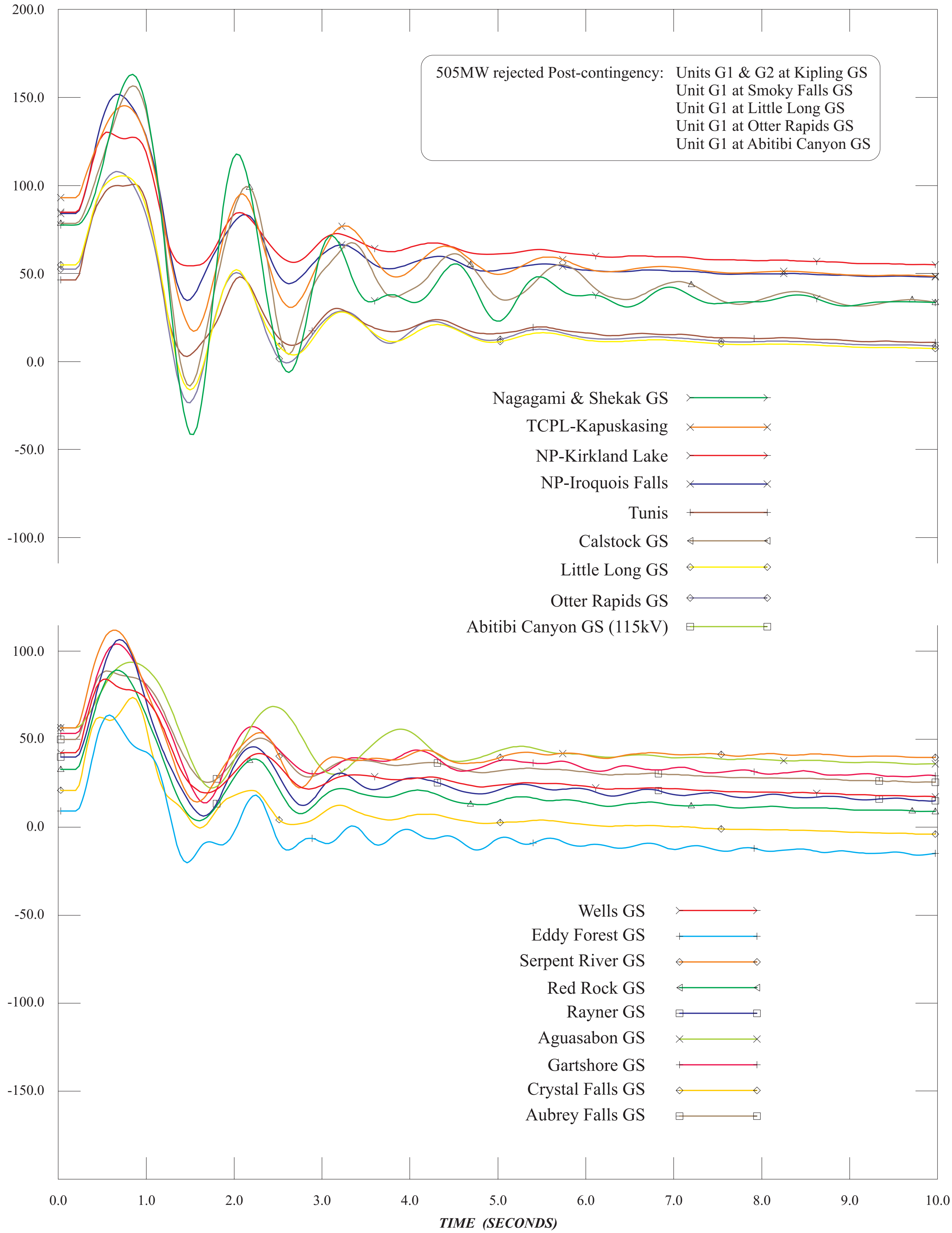


Response of the SVCs, together with the associated system voltages, for a 3-phase fault on circuit X503E at Hanmer TS

For a Flow South of 2427MW including required margin

DIAGRAM 41

28th April 2007

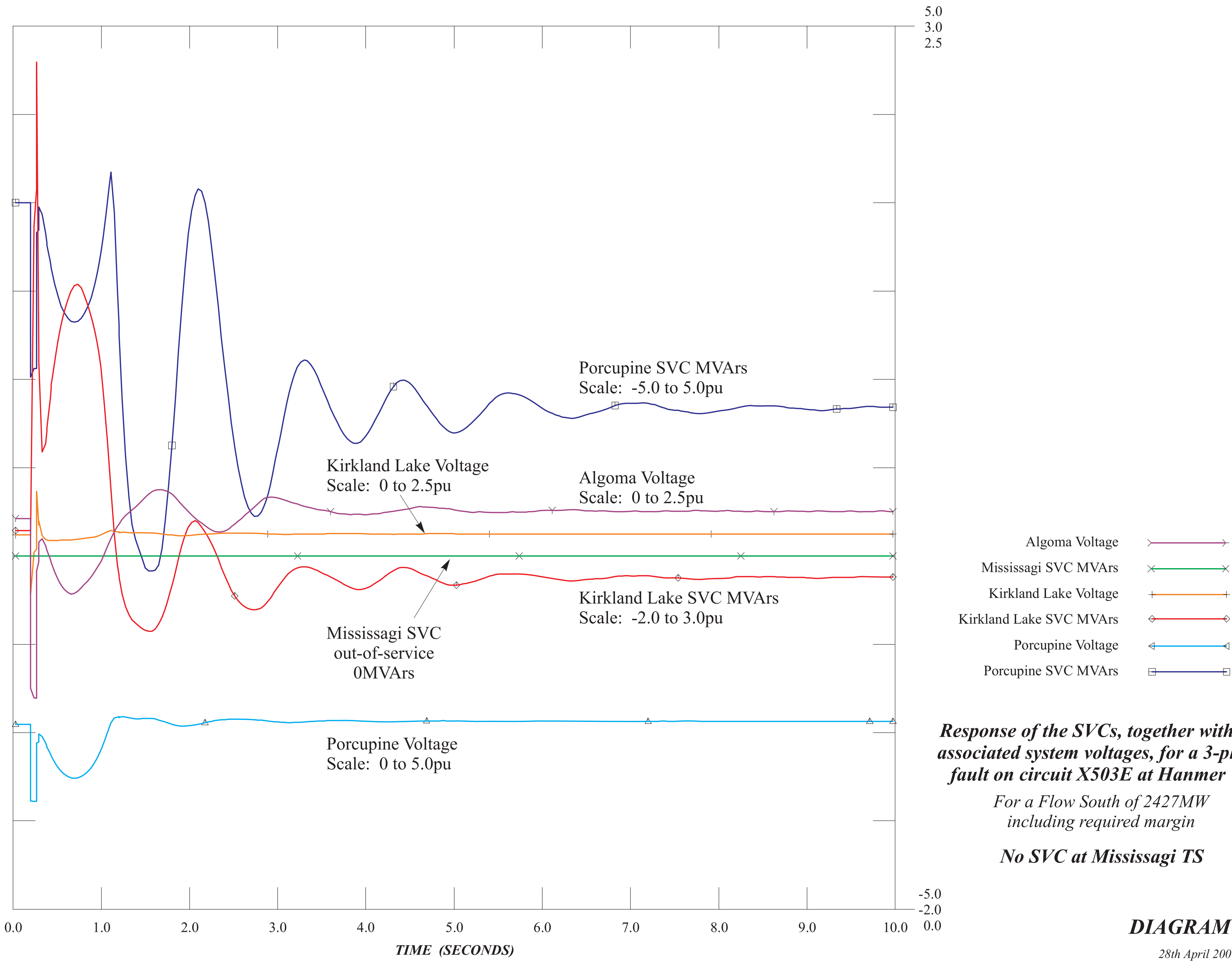


Generator Rotor Angle Responses to a 3-Phase fault on circuit X503E at Hanmer TS

With no SVC at Mississagi TS & a Flow South of 2427MW including the required margin

DIAGRAM 42

3rd May 2007



Response of the SVCs, together with the associated system voltages, for a 3-phase fault on circuit X503E at Hanmer TS

For a Flow South of 2427MW including required margin

No SVC at Mississagi TS

DIAGRAM 43

28th April 2007

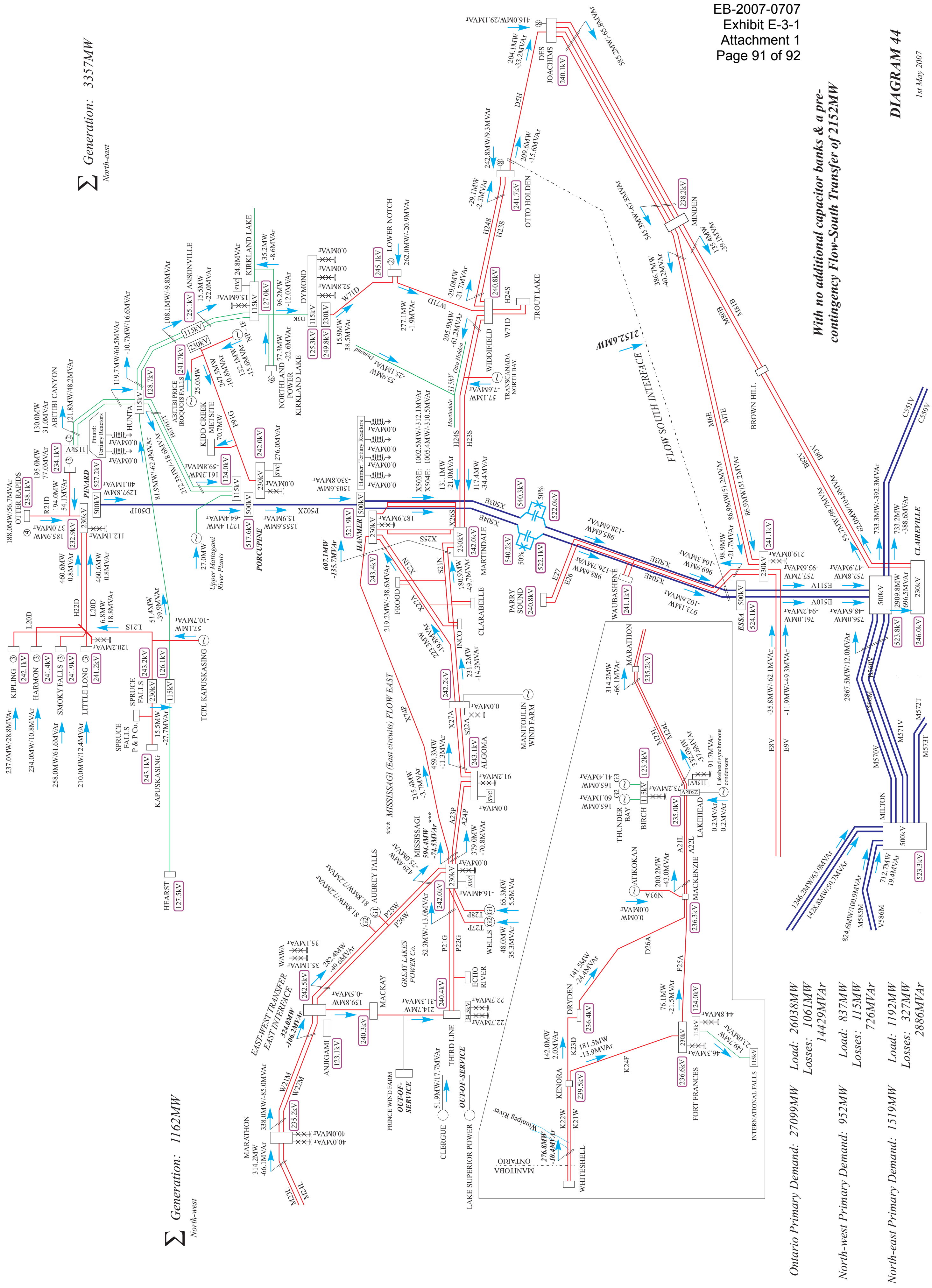
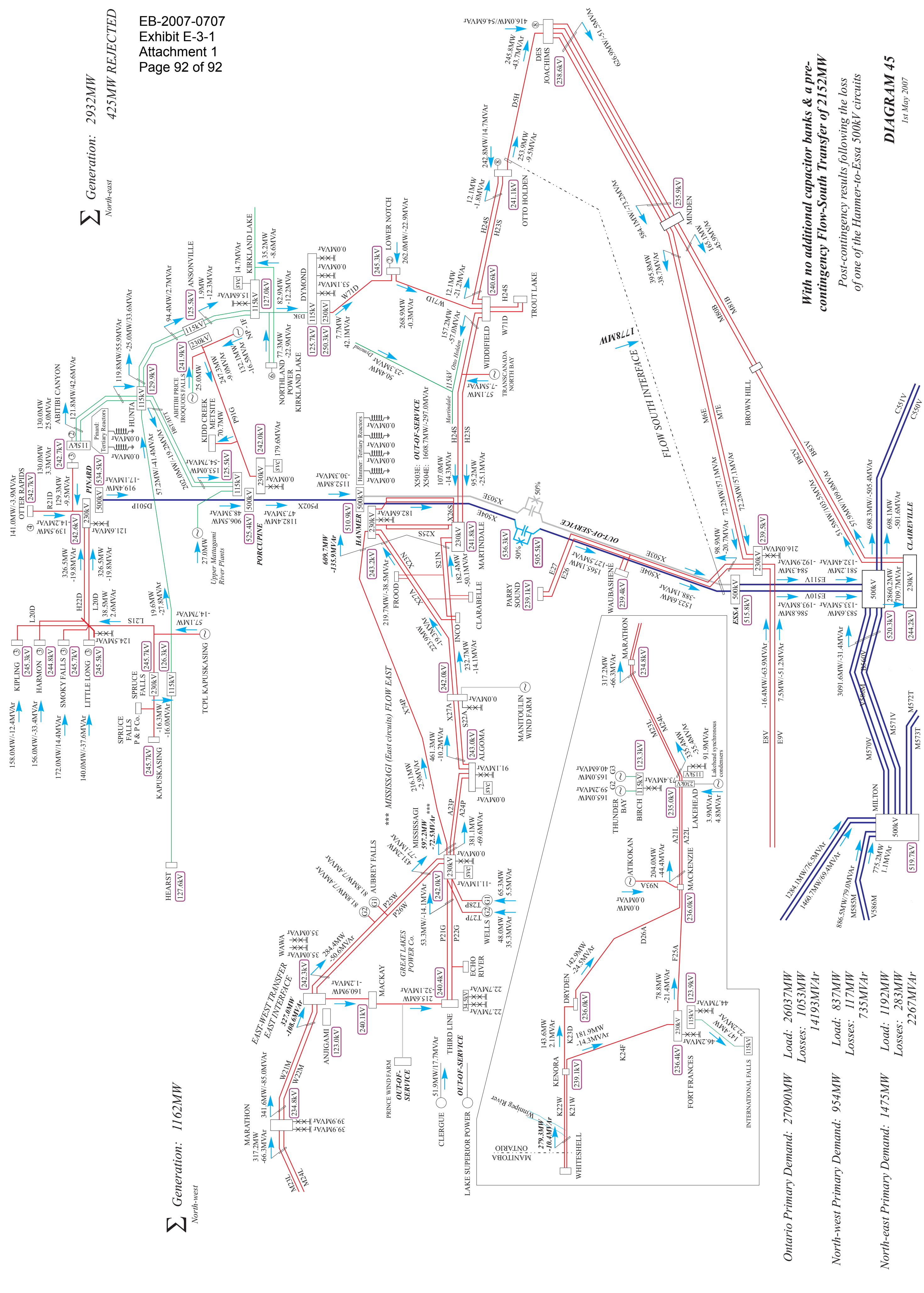


DIAGRAM 44
1st May 2007
With no additional capacitor banks & a pre-contingency Flow-South Transfer of 2152MW
Σ Generation: 3357MW
North-east
Σ Generation: 1162MW
North-west
Ontario Primary Demand: 27099MW
Load: 26038MW
Losses: 1061MW
14429MVAr
North-west Primary Demand: 952MW
Load: 837MW
Losses: 115MW
726MVAr
North-east Primary Demand: 1519MW
Load: 1192MW
Losses: 327MW
2886MVAr
FLOW SOUTH INTERFACE
2152.6MW
EAST-WEST TRANSFER EAST INTERFACE
324.0MW
-106.2MVAr
*** MISSISSAGI (East circuits) FLOW EAST
MISSISSAGI
594.4MW
-74.5MVAr ***
PORCUPINE
HANMER
PINARD
ESSA
CLAIREVILLE
MILTON
MINDEN
DES JOACHIMS
OTTO HOLDEN
WIDDIFIELD
MARTINDALE
MARATHON
WAWA
MACKAY
THIRD LINE
KENORA
DRYDEN
FORT FRANCES
MACKENZIE
LAKEHEAD
THUNDER BAY
BIRCH
WHITESHELL
MANITOBA
ONTARIO

EB-2007-0707
Exhibit E-3-1
Attachment 1
Page 92 of 92



Ontario Energy Board (Board Staff) INTERROGATORY #62 List 1

Interrogatory

Issue 4.1
Are the proposed 2009 and 2010 Sustaining and Development and Operations capital expenditures appropriate, including consideration of factors such as system reliability and asset condition?

Reference:
a) ExhD1/Tab3/Sched3/pp 17-18 / Project D9, D10, D11
b) Filing Requirements for Transmission and Distribution Applications, November 14, 2006 (EB-2006-0170)/Sec. 5.3.2/paragraph 3

Preamble:
Reference a) above indicate that the projects will only be implemented if the OPA so recommends.
Reference b) indicate that even though the net present value for a non-discretionary project need not be shown to be greater than zero, an evaluation of the economic benefits e.g., the evaluation of the reduced congestion on the system is appropriate.

Questions:
(i) are these projects included in the IPSP?
(ii) If the response to (i) is affirmative, is it reasonable to assume that the OPA will recommend implementation of these projects once its IPSP plan is approved by the OEB?
(iii) Please provide an estimate of the reduced congestion attributable to the three projects over an appropriate study horizon, and listing all assumptions.

Response

(i) No. The references refer to the projects to install shunt capacitor banks at Algoma TS, Mississagi TS and static var compensators at Mississagi TS. In its Integrated Power System Plan (IPSP) the Ontario Power Authority (OPA) considers these projects to be Near-Term Transmission Reinforcements and hence,"pre-IPSP". Pre-IPSP projects will be in-service prior to the facilities contemplated by the IPSP are required and hence are not part of the IPSP. For a discussion of these projects in the IPSP, please see EB-2007-0707, Exhibit E, Tab 3, Schedule 2.

(ii) Not applicable.

(iii) In the IPSP, the OPA estimates the reduced congestion at 130 MW. See EB-2007-0707, Exhibit E, Tab 3, Schedule 2, Page 7 for a discussion of the estimate for reduced congestion.

These documents are available on the OEB website (http://www.oeb.gov.on.ca/OEB/) under the Integrated Power System Plan (IPSP) Review. Copies of the documents are also attached to this interrogatory as Attachment 1:

EB-2007-0707 Exhibit E, Tab 3, Schedule 2

SUDBURY WEST TRANSMISSION REINFORCEMENT

1.0 EXECUTIVE SUMMARY

The purpose of this project is to meet the Directive's renewable goals by facilitating and enabling the development of renewable resources in the area from Sudbury to eastern Lake Superior including Manitoulin Island ("Sault/Algoma area"). This project will also reduce congestion on the transmission path from the Mississagi station to the Sudbury area from the west.

Most of the major northeastern Ontario wind resources included in the Plan are located in the Sault/Algoma area (over 1,000 MW of good wind potential has been identified in the east Lake Superior area and over 1,000 MW on Manitoulin Island). The Plan includes 1,000 MW of this over 2,000 MW total. To facilitate its development and integration into the Ontario grid, the adequacy of transmission capacity west of Sudbury was assessed and a plan was developed to stage reinforcements as required. In conjunction with this project, two other projects are also essential for developing the large renewable potential in the Sault/Algoma area. These are the Enabling Manitoulin Renewable Resource Development (Exhibit E-3-10) for enabling renewable developments on the Manitoulin Island, and the East Lake Superior Transmission Reinforcement project (Exhibit E-3-4) for enabling renewable developments along the eastern shore of Lake Superior.

Presently, the transfer capability west of Sudbury is about 670 MW. The near-term upgrades planned for the North-South Tie (Exhibit E-3-1, North-South Transmission Reinforcement) will provide an added benefit of increasing the transfer capability west of Sudbury by about 130 MW to about 800 MW. This capability is expected to be adequate for the near-term committed and planned generation developments west of Sudbury.

If moderate transmission capacity upgrades are warranted, a shunt capacitor bank at Algoma TS and a shunt capacitor bank and a static-var-compensator ("SVC") at Mississagi TS can be installed to obtain an increase of another 130 MW to about 930 MW.

These facilities can be placed in-service in two to three years and their commitment can wait to be coordinated with further resource development.

As noted, the Plan includes 1,000 MW of wind generation development potential in the Sault/Algoma area, beyond that committed and planned in the near-term. Major transmission reinforcement is required for this level of development. To meet this need, the OPA has recommended in the Plan a second Hanmer TS to Mississagi TS transmission line. This line would be built as a 500 kV line and operated initially as a 230 kV line. This would provide transmission capability of about 1,400 MW. If further capacity is required, this line and the existing companion line could be converted for operation at 500 kV. These reinforcements can be coordinated to match resource developments in the Sault/Algoma area.

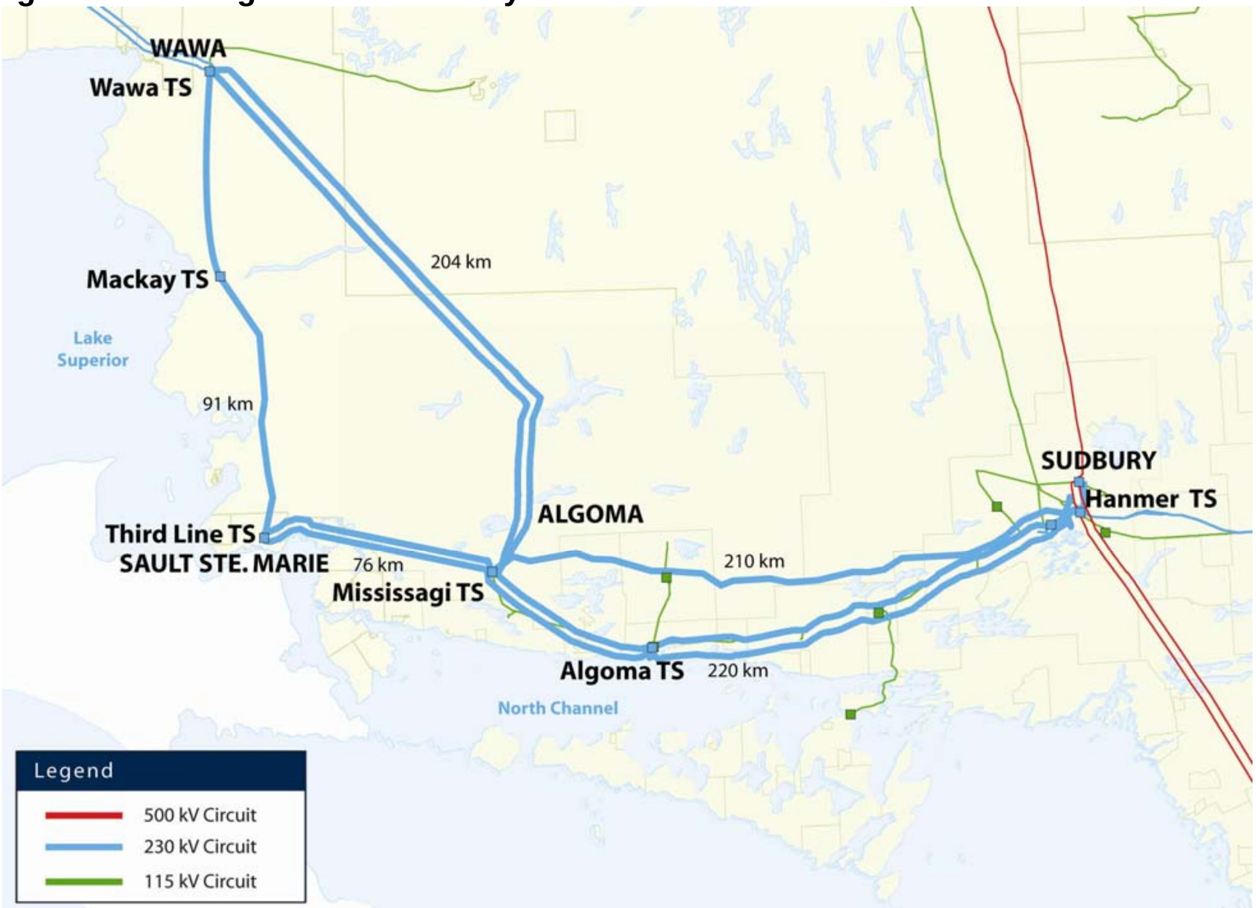
Ordinarily, development work would need to be initiated soon to meet the 2017 projected in-service date for this new line. However, there is already an approval under the *Environmental Assessment Act* (the “EA Act”) for the provision of a second 500 kV line on the existing Hanmer TS to Mississagi TS right-of-way. Therefore, subject to confirming that this EA approval continues to be valid (which the OPA understands to be the case), the main development work for this new line can likely wait until 2014 and can be coordinated with resource development in the area and other planned transmission reinforcements, including reinforcements to the North-South Tie. However, it is recommended that some preliminary work, including more detailed technical studies and early public consultation work, be initiated following the approval of the IPSP.

2.0 EXISTING FACILITIES IN THE SAULT/ALGOMA AREA

2.1 Transmission System

The transmission system in the Sault/Algoma area is shown in Figure 1 below.

Figure 1: Existing Transmission System



Source: Hydro One Networks and OPA

This transmission system between Wawa and Sudbury serves about 500 MW of load and about 1,100 MW of generation in the Sault/Algoma area. It also provides the capability to transfer generation surplus in the area, after supplying local loads, to the Sudbury area. As well, it provides a connection for power transfers, up to 300 MW, from or to northwestern Ontario through the East-West Tie (a 230 kV connection between northwestern Ontario and northeastern Ontario) at Wawa TS.

Mississagi TS is an important hub for the bulk transmission system in the Sault/Algoma area. There are two 230 kV circuits between Mississagi TS and Wawa TS, and two 230 kV circuits from Mississagi TS to Third Line TS in Sault Ste. Marie. A 230 kV circuit was recently added by Great Lakes Power between Third Line TS and Wawa TS.

To the east of Mississagi TS, there are three 230 kV circuits connecting it with the Sudbury area, one circuit to Hanmer TS and two to Martindale TS, a distance of approximately 200 km. These three circuits provide approximately 670 MW of transfer capability from Mississagi TS to Sudbury. There are near-term upgrades planned for the North-South Tie (Exhibit E-3-1) which will also increase the transfer capability to Sudbury from the west. Following their being brought into service in 2010, the transfer capability from Mississagi TS to the Sudbury area will be increased by about 130 MW, from 670 MW to 800 MW.

2.2 Load and Generation

Figure 2 shows the location of major load and generation centres in the Sault/Algoma area.

Figure 2: Generation and Load Centres

Source: Hydro One Networks and OPA

The generation in the area comprises three types - hydroelectric, gas-fired and wind - with a total installed capacity of about 1,100 MW as shown in Table 1.

Table 1: Generation in Sault/Algoma area west of Mississagi TS

Station	Type	Capacity (MW)
McPhail GS	hydro	11
High Falls GS	hydro	45
Scott GS	hydro	20
Steephill GS	hydro	15
Harris GS	hydro	11
Mission Falls GS	hydro	14
Gartshore GS	hydro	22
Hogg GS	hydro	15
Andrews GS	hydro	39
Hollingsworth GS	hydro	22
Mackay GS	hydro	45
Clergue GS	hydro	52
Aubrey GS	hydro	164
Wells GS	hydro	241
Rayner GS	hydro	47
Red Rock	hydro	42
Serpent River	hydro	7
Aux Sable GS	hydro	4
Lake Superior Power	gas	120
Prince I & II	wind	189
	Total	1125

Source: OPA

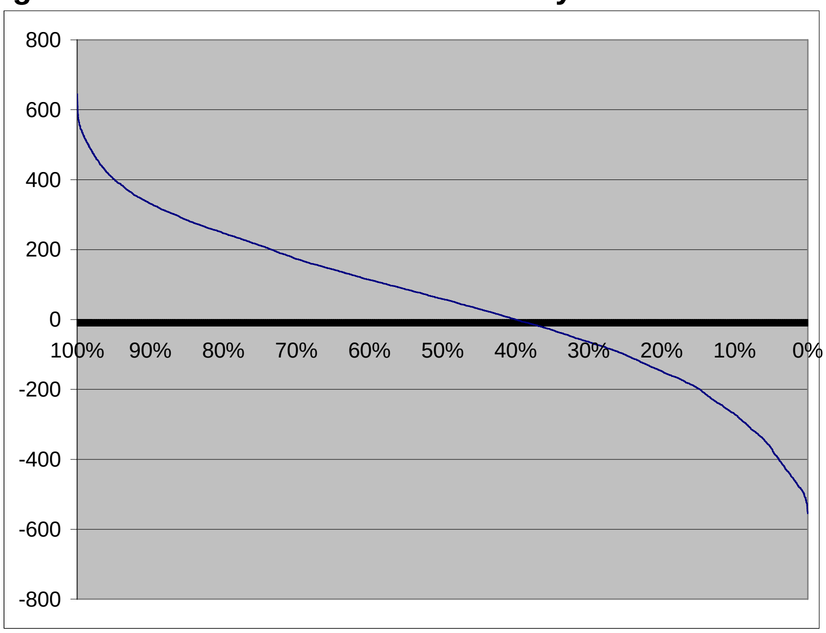
The loads in the Sault/Algoma area that impact on the power transfer from Mississagi TS to the Sudbury area are those located west of Mississagi TS and south of Wawa TS. These loads total about 400 MW, of which almost all of it is centered around the City of Sault Ste. Marie.

2.3 Sudbury West Transfers

Based on the installed capacity of the generation and local load in the Sault/Algoma area, and the potential inflow of 300 MW from northwestern Ontario, the westbound transfer from Mississagi TS to Sudbury can potentially reach 1,000 MW, which would exceed the 670 MW existing capacity. Actual transfers are, however, not as high. There are a number of factors that need to be considered in determining the transfer level west of Sudbury. They include: the operating pattern and water availability of the hydroelectric generation plants in the area, the variability of wind generation, the operation of coal generation in northwestern Ontario, and the operation of gas generation in Sault Ste. Marie. The diversity of the generation type and the temporal variation in their operation generally reduce the west of Sudbury transfers to a lower level than the 1,000 MW based on installed capacities.

The actual power transfers from Mississagi TS to Sudbury recorded in 2006, in a duration form, are shown in Figure 3. It shows that the maximum transfer level was under 600 MW.

Figure 3: Eastbound flow into Sudbury in 2006



Source: OPA

There are new and committed generation developments west of Sudbury, including those in northwestern Ontario that will increase the transfer level in the near future. These are shown in Table 2 below.

Table 2: Committed and planned near-term generation developments west of Sudbury

Type	Name	Capacity (MW)	Estimated In-service Date	Location
Hydro	RES I Umbata Falls - committed	23	2008	Northwest
Hydro	Lac Seul	13	2008	Northwest
Hydro	Cameron Falls	4	2008	Northwest
Hydro	Alexander	1	2008	Northwest
Hydro	Espanola	16	2008	Algoma
Gas	CHP Algoma - committed	63	2009	Algoma
Wind	RESOP - committed	140	2009	Algoma
Hydro	Pine Portage	2	2010	Northwest
Wind	Wind Northeast RESOP	100	2011	Algoma
Wind	Wind Northwest RESOP	10	2011	Northwest
Hydro	Ragged Chute	4	2011	Northwest
Hydro	At Highway 17	3	2011	Northwest
Hydro	Trowbrdige Falls	1	2012	Northwest
Hydro	Northern Thunder Bay	1	2012	Northwest
Hydro	Bentley Creek	2	2012	Northwest
Biomass	Biomass Atikokan	35	2012	Northwest
Biomass	Biomass northwest	10	2012	Northwest
Hydro	25.6 - 19.2 km from mouth	10	2012	Northwest
	Total	438		

Source: OPA

2.4 Near-Term Transmission Reinforcements

As noted earlier, there are near-term upgrades planned for the North-South Tie (Exhibit E-3-1) which will increase the transfer capability west of Sudbury by approximately 130 MW to about 800 MW. This capability increase is expected to be adequate for the above-mentioned near-term committed and planned generation developments.

Further moderate transmission upgrades can accommodate some additional generation development. The installation of a shunt capacitor bank at Algoma TS and a shunt capacitor and static-var-compensator at Mississagi TS could further increase transmission capacity by about 130 MW to about 930 MW. The installation of shunt capacitors and

SVCs involve typical lead-times of eighteen months for a shunt capacitor and two to three years for an SVC. The typical cost of shunt capacitor bank is about $5 million and $30 million for an SVC.

3.0 NEED FOR MAJOR TRANSMISSION REINFORCEMENT

The Plan includes 1,000 MW of potential wind generation in Sault/Algoma area. This is in addition to near-term committed and planned renewable resources. This 1,000 MW is required to meet the Directive's renewable goals.

The above-mentioned near-term transmission upgrades will increase the transmission capacity of the west of Sudbury transmission system to approximately 930 MW. However, this is not sufficient to enable the development of the 1,000 MW of planned wind generation in the Sault/Algoma area identified in the Plan. Additional transmission capacity of approximately 500 MW is required. The OPA believes that this is sufficient considering the operating nature of the wind resources and the diversity of generation type in this area.

This additional transmission capacity is needed in 2017 in coordination with the transmission reinforcement proposed for the North-South Tie.

4.0 ALTERNATIVES TO REINFORCING THE TRANSMISSION SYSTEM EAST OF MISSISSAGI TS

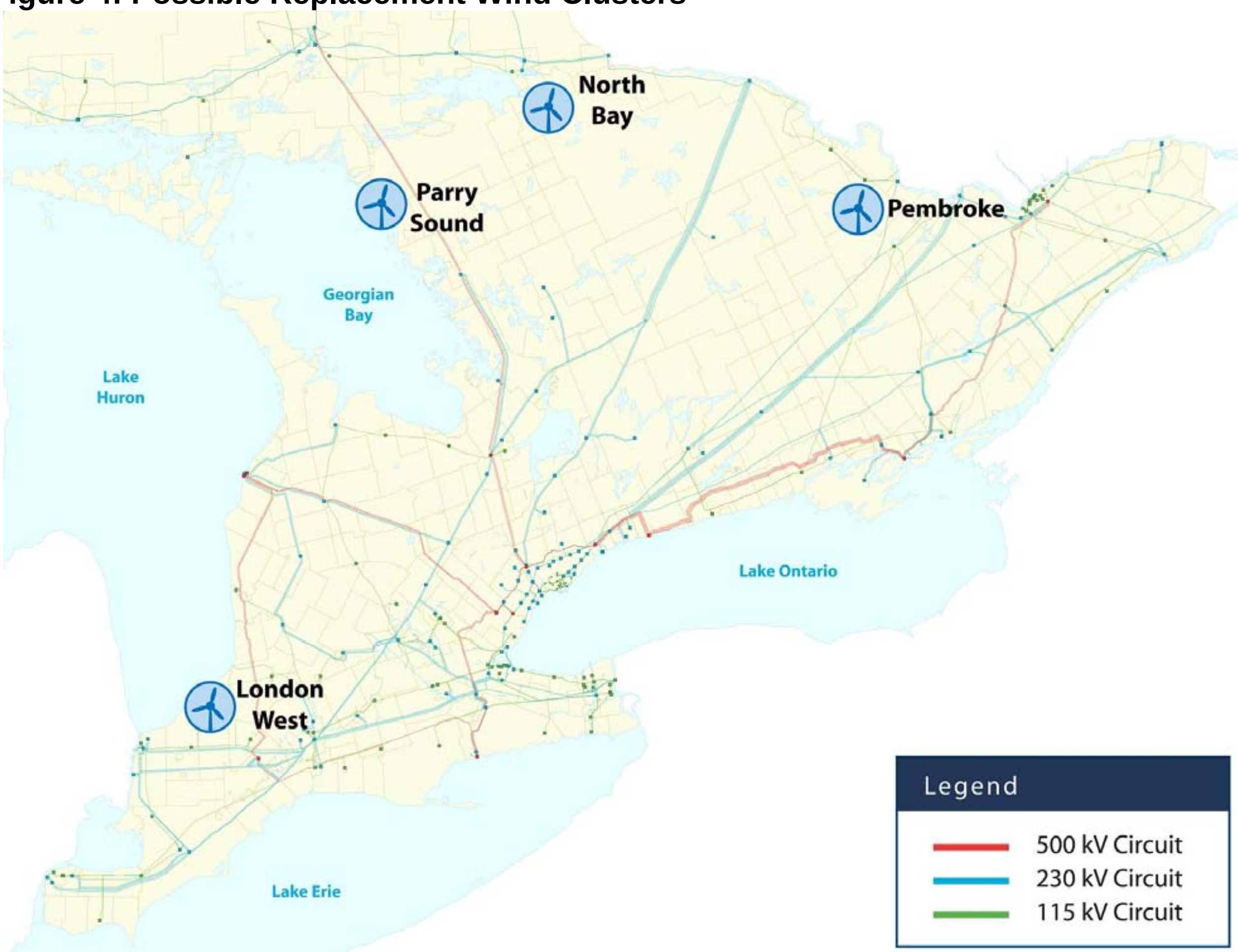
The alternative options to reinforcing the transmission system between Mississagi TS and Sudbury are:

- Option 1 - Development of wind projects in other parts of Ontario to meet the Directive's renewable target;
- Option 2 – Firm purchase of hydro power from Manitoba to meet the Directive's renewable target; and
- Option 3 - Firm purchase of hydro power from Québec or Labrador to meet the Directive's renewable target.

The recommended list of Large Wind generation developments to meet the renewable target in the Directive is shown in Exhibit D-5-1, Table 33, and is based on the all-inclusive LUEC analysis, described in Exhibit E-2-2.

Option 1 above would replace approximately 1,000 MW of Sault/Algoma wind development with a similar amount of other wind generation development located elsewhere in Ontario which have not been included in the Plan. Possible replacement clusters are in the North Bay area, Parry Sound area, in the area west of London, and in the Pembroke area, as shown in Figure 4.

Figure 4: Possible Replacement Wind Clusters



Source: Hydro One Networks and OPA

Table 3 shows the all-inclusive LUEC for the Manitoulin Island and the four replacement clusters, as well as the annual cost difference based on their respective LUECs, based on a production of 951 GWh a year.

Table 3: All Inclusive LUEC and Possible Replacement Wind Cluster – Cost Impact

Area	Capacity (MW)	All inclusive LUEC (¢/kwh)	Annual Cost Difference ($ mil)	% Increase in Annual Cost
Manitoulin	400	9.13		
Pembroke	207	9.59	4.4	5%
West of London	337	9.66	5.0	6%
Parry Sound	237	9.81	6.5	7%
North Bay	402	10.10	9.2	11%

Source: OPA

The results indicate that if the 400 MW of wind potential on Manitoulin Island were to be replaced by the Pembroke, London West, Parry Sound or North Bay clusters, the system cost would increase by an amount between $4.4 million and $9.2 million annually.

A similar comparison was carried out for the 600 MW East Lake Superior development. The cost was compared to the cost of replacement by the two best remaining clusters in southern Ontario: Pembroke and West of London. This comparison is shown in Table 4.

Table 4: All inclusive LUEC and possible replacement wind cluster – cost impact

	Capacity (MW)	All inclusive LUEC (¢/kwh)	Annual Cost Difference ($ mil)	% Increase in Annual Cost
East Lake Superior	600	9.13		
Pembroke and West of London	544	9.63	6.9	5%

Source: OPA

The results indicate that if the 600 MW of wind potential on Manitoulin Island were to be replaced by the Pembroke and London West Parry clusters, the system cost would increase by approximately $6.9 million annually.

Thus, Option 1 is not a cost effective option when compared with the Manitoulin Island wind generation development. Moreover, there are no other reasons (reliability, flexibility, feasibility) that would make higher cost wind preferable to wind generation development in Sault/Algoma area.

Options 2 and 3 are possible substitutes for Manitoulin wind. However, as described in Exhibits E-3-5 and E-3-6, there are significant uncertainties surrounding the feasibility and economics of these potential purchases. The OPA recommends further exploring purchases with Manitoba, Québec and Labrador, but due to the uncertainties involved, it is the OPA's view that it would be imprudent to include them in the Plan at this time.

5.0 TRANSMISSION ALTERNATIVES

A new transmission line connecting Mississagi TS to Hanmer TS in Sudbury will provide a significant increase in the transfer capability. Adding a fourth 230 kV circuit will increase the west of Sudbury transfer capacity to about 1,400 MW, sufficient for the wind development identified in the Plan for the Sault/Algoma area.

In the planning of the west of Sudbury system in the past, the need for two 500 kV lines between Hanmer TS in Sudbury and Mississagi TS was identified. The first line was built in the 1990s. The right-of-way for this line has sufficient space for a second line and the associated EA approval was granted for the construction of two 500 kV lines along this right-of-way. For this reason, building the second line along this existing right-of-way would most likely be the best alternative for reinforcing the west of Sudbury transmission system.

Since the existing line, although built for conversion to 500 kV, is currently operating at 230 kV, the initial stage development of the new line would also be operated at 230 kV. This is to minimize the cost of converting the existing line to 500 kV and providing 500/230 kV autotransformation at Mississagi. As indicated earlier, the capacity provided for this initial stage should be adequate for the 1,000 MW of wind generation development planned for this area. In the future, should more capacity be required, both the Hanmer TS to Mississagi TS lines could be converted to 500 kV operation.

The cost of building a second 500 kV line for initial operation at 230 kV is estimated at $210 million.

With the EA for the second Hanmer TS to Mississagi TS in hand, a three year lead time for developing this line is a reasonable estimate. For this reason and given that a number of moderate capacity increase options are available, there is sufficient time to monitor the development of resources in the Sault/Algoma area and the utilization of the west of Sudbury system before committing to major new transmission in this area.

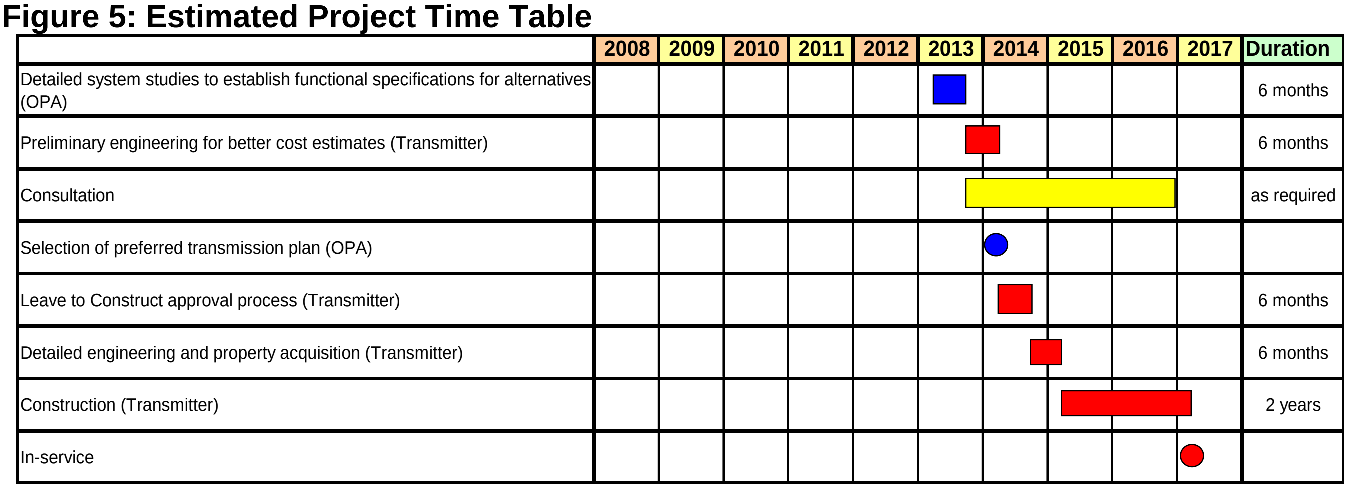
6.0 NEAR-TERM NEEDS

A new Mississagi TS to Hanmer TS transmission line is required by 2017. Ordinarily, development work would need to be initiated soon to meet the 2017 projected in-service date for this new line. However, there is already an approval under the EA Act for the provision of a second 500 kV line on the existing Hanmer TS to Mississagi TS right-of-way. Therefore, development work for this new line can likely wait until 2014 and can be coordinated with resource development in the area and other planned transmission reinforcements, including reinforcements to the North-South Tie. However, it is recommended that some preliminary work, including more detailed technical studies and early public consultation work, be initiated following the approval of the IPSP.

7.0 ESTIMATED PROJECT TIME TABLE FOR NEW TRANSMISSION

Figure 5 shows the estimated project time table for the construction of the second transmission line on the Hanmer TS to Mississagi TS right-of-way.

Figure 5: Estimated Project Time Table



Source: OPA

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

Interrogatory

Issue 4.1
Are the proposed 2009 and 2010 Sustaining and Development and Operations capital expenditures appropriate, including consideration of factors such as system reliability and asset condition?

Reference:
ExhD2/Tab2/Sched3/Invest.Summary/Ref.#D23, #D24, #D25, #D26, #D27, #D28, and #D29

Preamble:
Hydro One is seeking approval in this hearing for the seven "Load Customer Connection" projects whose in-service dates are within the two test years 2009/2010.

Request:
Please provide for each project a copy of the spread sheet depicting the economic evaluations, showing all assumptions including the discount rate..etc, pursuant to the requirements of the Transmission System Code (Section 6.3). Where for any project, more than a single customer is contributing capital, please provide the details of the study for each customer.

Response

Hydro One is in the process of seeking consent from the affected customers to release the requested information and will provide the requested evaluations once customer consent is obtained following the Board's confidentiality filing guidelines.

Ontario Energy Board (Board Staff) INTERROGATORY #64 List 1

Interrogatory

Issue 4.1
Are the proposed 2009 and 2010 Sustaining and Development and Operations capital expenditures appropriate, including consideration of factors such as system reliability and asset condition?

Reference: ExhD2/Tab2/Sched3/Invest.Summary/Ref.#D30, #D31, #D32, #D33, and #D34

Preamble:
Hydro One is seeking guidance in this hearing for the five "Load Customer Connection" projects whose in-service dates are beyond the two test years 2009/2010.

Request:
Please provide for each project a copy of the spread sheet depicting the economic evaluations, showing all assumptions including the discount rate …etc, pursuant to the requirements of the Transmission System Code (Section 6.3). Where for any project, more than a single customer is contributing capital, please provide the details of the study for each customer.

Response

Hydro One is in the process of seeking consent from the affected customers to release the requested information and will provide the requested evaluations once customer consent is obtained following the Board's confidentiality filing guidelines.

<u>Ontario Energy Board (Board Staff) INTERROGATORY #65 List 1</u>

Interrogatory

Issue 4.1
Are the proposed 2009 and 2010 Sustaining and Development and Operations capital expenditures appropriate, including consideration of factors such as system reliability and asset condition?

<u>Reference:</u> a) ExhD2/Tab2/Sched3/Ref.# O1
b) ExhD1/Tab3/Sched4/p 5/Table 2

<u>Preamble:</u>
In Reference a), the cost for the "Grid Operations Control Facility" is shown to be $ 27 million, while in Reference b), the investment for the two test years for that same investment is shown to be $15.1 million for 2009, and $9.8 million for 2010 i.e., a total of $ 24.9 million.

<u>Clarification:</u>
Please provide clarification in regard to the apparent discrepancy between the two amounts.

Response

There is no discrepancy between these two references.

Reference a) shows $27 million as the total gross cost (including expenditures outside the test years) for the NMS Upgrade, which is only one investment out of several included for the "Grid Operations Control Facility" component of the work. The figures quoted in Reference b) ($15.1 million for 2009, and $9.8 for 2010 i.e. a total of $24.09 million) are actually the sum of all Grid Operations Control Facility investments in the test years.

Ontario Energy Board (Board Staff) INTERROGATORY #66 List 1

Interrogatory

Issue 4.1
Are the proposed 2009 and 2010 Sustaining and Development and Operations capital expenditures appropriate, including consideration of factors such as system reliability and asset condition?

Reference: a) ExhD2/Tab2/Sched3/Ref.# O2
b) ExhD1/Tab3/Sched4/pp 10-13

Preamble:
In Reference a), the cost for the "Integrating Operating Infrastructure" is shown to be $ 11.4 million for the period up to mid 2010.

In Reference b), there are a number of investments listed as shown in the Table below:

Operating Infrastructure	2009	2010
Hub-Site End of Life Replacement	$3 million	$3 million
Telecom Wide Area Network		$13 million
Other Miscellaneous Projects	$0.1 million	$3.1 million

Clarification:
Please provide clarification in regard to the apparent discrepancy between the two sources in regard to the investment amounts.

Response

There are no discrepancies between these two references.

Reference a) shows $11.4 million as the total gross cost (including expenditures outside the test years) for the Hub Site EOL Replacement program, which is only one investment out of several for "Integrating Operating Infrastructure". The table provided by the OEB, which is derived from Reference b), is actually the sum of all investments for Integrating Operating Infrastructure during 2009 and 2010.

The investment for "Hub Site EOL Replacement" includes expenditures of $.2 million in 2007 and $5.2 million in 2008, in addition to the $3 million for 2009 and $3 million for 2010 for a total of $11.4 million.

Ontario Energy Board (Board Staff) INTERROGATORY #67 List 1

Interrogatory

Issue 4.1
Are the proposed 2009 and 2010 Sustaining and Development and Operations capital expenditures appropriate, including consideration of factors such as system reliability and asset condition?

Reference: a) Exh D1/Tab2/Sched 1/AttA

Preamble:

Tables 3-1, 3-2, 3-3 summarize the findings of the ACA Process Audit. In regard to report section 4.5 HV/LV Switches, the findings indicate that a reasonable data collection plan should be established.

Question:

Please indicate:
a) what is Hydro One's plan to address the issue of stale data?
b) what is the timeline?

Response

a) Hydro One temporarily suspended the switch maintenance to accommodate other priority work. This program was a source of data for the ACA process. Hydro One is restarting all the switch maintenance programs which will allow us to collect the required maintenance data.

b) Hydro One is restarting all the switch maintenance programs over the course of 2009 and 2010. The required maintenance data will be collected depending on the type of switch and switch maintenance frequency.

Ontario Energy Board (Board Staff) INTERROGATORY #68 List 1

Interrogatory

Issue 4.1
Are the proposed 2009 and 2010 Sustaining and Development and Operations capital expenditures appropriate, including consideration of factors such as system reliability and asset condition?

Reference: a) Exh D1/Tab2/Sched 1/AttA

Preamble:

Tables 3-1, 3-2, 3-3 summarize the findings of the ACA Process Audit. In regard to report section 4.9 Wood Poles, the findings indicate that the Health Index formulation is not an investment driver.

Question:

Does Hydro One intend to implement the auditor's recommendation of developing a health index in such a manner as to facilitate specific investment decisions?

Response

No. Hydro One's specific wood structure investments are based on end of life parameters rather than a numeric "health index" and as such Hydro One does not see a need to develop a "health index" for each structure to facilitate specific investments. Wood pole end of life is primarily based on the degree of rot/damage, external and internal, and for wood arms the end of life is based on a rating that is correlated to observed deterioration. Hydro One has assessed the majority of its wood pole structures, and continues to assess them on a regular basis to monitor deterioration. With the information available on wood pole structures, those involved in the asset condition assessment and planning processes have a good understanding of the requirements for future investments.

Ontario Energy Board (Board Staff) INTERROGATORY #69 List 1

Interrogatory

Issue 4.1
Are the proposed 2009 and 2010 Sustaining and Development and Operations capital expenditures appropriate, including consideration of factors such as system reliability and asset condition?

Reference: a) Exh D1/Tab2/Sched 1/AttA
Preamble:
Tables 3-1, 3-2, 3-3 summarize the findings of the ACA Process Audit. In regard to report section 4.11 Right of Way, the findings indicate that the Health Index is not generally used in making investment decisions.
Question:
What does Hydro One intend to do in this regard?

Response

A numeric "health index" is not necessary for vegetation management as the information collected from condition patrols is sufficient to make an appropriate investment decision. Condition patrols are carried out at about mid-cycle. Key information collected during a condition patrol includes brush/tree heights and an estimate of when work is required. These patrols are carried out by trained and experienced staff that record the data for further consideration and work planning. The work triggers are well understood by field staff and those planning the work and are therefore preferred over a numeric 'health index".

Ontario Energy Board (Board Staff) INTERROGATORY #70 List 1

Interrogatory

Issue 4.1
Are the proposed 2009 and 2010 Sustaining and Development and Operations capital expenditures appropriate, including consideration of factors such as system reliability and asset condition?

Reference: a) Exh D1/Tab2/Sched 1/AttA
Preamble:
Tables 3-1, 3-2, 3-3 summarize the findings of the ACA Process Audit for Priority 2 Assets. In regard to report sections 5.4, 5.8, 5.10, 5.14 and 5.15, the findings indicate various concerns.
Question:
Please indicate what Hydro One intend to do in each instance?

Response

Section 5.4 Power Line Carrier (PLC)

Hydro One believes a numeric "health index" is unnecessary to make investment decisions for PLC. As discussed in Exhibit D1, Schedule 2, Tab 3 on page 35, 67 of the 79 PLC systems which are more than 20 years old and experiencing increasing failure rates, lack of manufacturer support and lack of spare parts have now been replaced. The plan is to complete the remaining 12 by end of 2010. It is expect that a renewed PLC replacement program will not be required again until these replaced systems reach end of life.

Section 5.8 Station Cable and Potheads

Hydro One does not believe the Hatch report identifies a concern. In fact, page 40 of the report states that Hydro One's approach is "Consistent with Industry Best Practices".

Section 5.10 Station Grounding Systems

Hydro One does not believe the Hatch report identifies a concern. In fact, page 42 of the report states that Hydro One's approach continues "to be consistent with the practices of other leading electric utilities".

Section 5.14 Drainage and Geotechnical

Hydro One does not believe the Hatch report identifies a concern. Hydro One has sufficient data to make investment decisions for Drainage and Geotechnical at this time. Hydro One will collect addition data to update the health index when it is warranted by the business need.

Section 5.15 System Security

Hydro One does not believe the Hatch report identifies a concern. Hydro One has sufficient data to make investment decisions for System Security and Fire Protection Systems at this time. Hydro One will collect additional data when it is warranted to make investment decisions.

Ontario Energy Board (Board Staff) INTERROGATORY #71 List 1

Interrogatory

Issue 4.2
Are the proposed 2009 and 2010 levels of Shared Services and Other Capital expenditures appropriate?

Reference: a) ExhD1/Tab3/Sched5/p 3/Table 2
b) Proceeding EB-2005-0501, ExhD1/Tab3/Sched5/p 2/Table 2

Preamble:
The investment amounts allocated to Transmission in $ millions for various categories in Reference a) for the years 2007 and 2008 are not consistent with the corresponding amounts reported in Reference b). For convenience, the table below lists the information from the two references.

	Reference.a), EB-2008-0272		Reference.b), EB-2005-0501	
	2007	2008	2007	2008
	in $ million	in $ million	in $ million	in $ million
Information Technology	14.7	11.9	67.1	26.0
Facilities & Real Estate	3.2	5.4	4.0	4.2
Transport&Work Equipment	9.9	12.4	10.4	9.7
Service Equipment	3.4	5.3	3.1	2.8

Clarification:
Please provide explanation to the change in the investment between the forecasted amounts in Reference b), EB-2005-0501, and the amounts listed in the submission by Hydro One for this proceeding in Reference a), EB-2008-0272.

Response

At the time of the last transmission filing (EB-2005-0501), 2007 and 2008 were the test years, the figures shown were forecasts developed in 2006 based on the best information available at that time. In the current application (EB-2008-0272), 2007 data is actual, and 2008 data is based on a forecast developed close to mid-year. In general, increases in 2008 reflect a general upward pressure on these shared services by the overall increase in the work program.

In EB-2005-0501 Information Technology costs included Cornerstone. The following table presents information in the same format between the two filings.

$/million	**EB-2008-0272**		**EB-2005-0501**	
	2007	**2008**	**2007**	**2008**
Information Technology	$14.7	$11.9	$10.1	$10.2
Cornerstone	$33.8	$72.5	$57.0	$15.8

Information technology items contributing to differences between actual and projected costs in 2007 and 2008 include costs for software refresh and maintenance and minor fixed assets whose variance is described in Board Staff Interrogatories 72 and 73. Development projects variances are mainly attributable to lower CIS project costs and lower Mobile IT costs in 2007 and 2008. The CIS upgrade project was deferred pending a decision regarding the timing of Cornerstone Phase 4 and the timing and impact of integrating smart meters with the customer billing and information applications.

Cornerstone variances are described in the response to Board Staff Interrogatory 74.

For Transport & Work Equipment, Facilities & Real Estate and Service Equipment, differences between EB-2006-0501 and EB-2008-0272 predominantly reflect the need to support larger work programs, the impact of which is particularly noticeable for the year 2008.

For example, in the case of Service Equipment, the results are reflected in additional requirements for Schnabel car upgrades, degassifiers and AED devices. The overall increases are offset by select project delays, such as the case in Real Estate and Facilities, which experienced a project delay for Picton Service Centre.

Ontario Energy Board (Board Staff) INTERROGATORY #72 List 1

Interrogatory

Issue 4.2
Are the proposed 2009 and 2010 levels of Shared Services and Other Capital expenditures appropriate?

Reference: a) ExhD1/Tab3/Sched6/p 5/Table 3
b) Proceeding EB-2005-0501, ExhD1/Tab3/Sched5/p 8/Table 4

Preamble:
The investment amounts in $ millions (total amount before allocation to Transmission) for the "Software Refresh & Maintenance" and for the "Windows (O/S)" in Reference a) for the years 2007 and 2008 are not consistent with the corresponding amounts reported in Reference b). For convenience, the table below lists the information from the two references.

	Amounts of Investment before Allocation to Transmission			
	Reference.a), EB-2008-0272		**Reference.b), EB-2005-0501**	
	2007	2008	2007	2008
	in $ million	in $ million	in $ million	in $ million
Software Refresh & Maintenace	11.9	7.2	6.6	6.4
Windows (O/S)	-	-	-	1.9

Clarification:
Please provide explanation to the change in the investment between the forecasted amounts in Reference b), EB-2005-0501, and the amounts listed in the submission by Hydro One for this proceeding in Reference a), EB-2008-0272. *(NM)*

Response

2007 actual Software Refresh and Maintenance Program Capital Expenditures were $5.3 million greater than forecast in EB-2005-0501. Hydro One spent $1.6 million on the upgrade of the BEA (middleware) enterprise bus/ihub application (subsystem that transfers data between computer components inside a computer or between computers or applications). This had been budgeted at $0.6 million. The project scope was expanded to address the requirements of the smart meter project which will also use this service oriented application architecture in its technical solution. In addition $5.4 million was spent on the acquisition of Oracle database applications specific to database management, security, database audit trails to meet Bill 198 requirements, multiple database upgrades to support Oracle 10G platform and for encryption technology. Only a portion of this work had been budgeted ($2.3 million). The opportunity was taken to ensure the database environment would be consistent with the Cornerstone project requirements hence the additional applications were purchased. Investments were also made in security software and firewalls in the amount of $1.7 million which were deemed required and had not been budgeted originally .

The 2008 actual spend was $1.1 million less than that forecast in EB-2005-0201. In 2008, a number of projects were deferred or reprioritized in support of the Cornerstone project. For example some additional Oracle software has been acquired to support security requirements for the next phase of Cornerstone, and to provide additional database management tools to Inergi at an unbudgeted cost of $0.6 million. As well, to accommodate the architectural design for Cornerstone additional capacity was added to the BEA software solution at an unbudgeted cost of $0.4 million, however doing so resulted in budgeted savings of $0.5 million in costs related to a Citrix based solution. Costs of $0.5 million which had been budgeted for security applications were expended in 2007 (Oracle database applications) rather than in 2008. An additional amount of $0.5 million was spent on a server refresh related to the build out of the “warm” disaster recovery site which was established with the Cornerstone project development site. A decision has been made not to proceed with a Vista upgrade which was budgeted at $1.9 million.

Ontario Energy Board (Board Staff) INTERROGATORY #73 List 1

Interrogatory

Issue 4.2
Are the proposed 2009 and 2010 levels of Shared Services and Other Capital expenditures appropriate?

Reference: a) ExhD1/Tab3/Sched6/p 7/Table 4
b) Proceeding EB-2005-0501, ExhD1/Tab3/Sched5/p 10/Table 5

Preamble:
The investment amounts in $ millions (total amount before allocation to Transmission) for the three components comprising the "IT Minor Fixed Assets Program Capital Expenditures" in Reference a) for the years 2007 and 2008 are not consistent with the corresponding amounts reported in Reference b). For convenience, the table below lists the information from the two references.
Clarification:

	Amounts of Investment before Allocation to Transmission			
	Reference.a), EB-2008-0272		**Reference.b), EB-2005-0501**	
	2007	2008	2007	2008
	in $ million	in $ million	in $ million	in $ million
IT Mainframe, servers, and Storage Program	8.4	8.2	3.9	2.7
IT Desktops, Tablets, Printers & Plotters	4.8	4.0	3.9	3.9
TelecomNetworks& PBX/Voicemail	1.2	3.3	0.8	1.4
Total	**14.4**	**15.4**	**8.6**	**8.0**

Please provide explanation to the change in the investment between the forecasted amounts in Reference b), EB-2005-0501, and the amounts listed in the submission by Hydro One for this proceeding in Reference a), EB-2008-0272.

Response

Actual minor fixed assets were $5.8 million greater in 2007 and $7.4 million greater in 2008 than those forecast in EB-2005-0501.

Actual mainframe, servers and storage costs in 2007 include smart meters as well as OGCC servers totaling $4.5 million. In 2008, the amount related to these items was $6.9 million. Neither of these two amounts was included in the historic filed amounts for 2007 and 2008. In 2008, projected data storage capital of $600 thousand was not incurred as

Hydro One moved to a shared service data model provided by Capgemini. Costs for this shared services model are included in OM&A and are reflected in sustainment costs

Desktop costs increased in 2007 as a result of Hydro One hiring more staff, the commencement of the Cornerstone project which required computers for contract staff and for training, and the increased use by field staff of tablets for data collection and for use with GIS applications. While a normal refresh cycle had been budgeted these additional demands required the purchase of additional equipment.

Telecom Network costs are higher in 2007 and 2008 due to replacement of end of life Private Branch Exchange (PBX) switches which the manufacturer announced would be no longer supported, the move to VOIP supported telecom equipment, refresh and upgrades to the data communications network to support Cornerstone go live and the WEP application rollout. Budget assumptions for 2007 and 2008 had assumed similar to historic spending on these items.

Ontario Energy Board (Board Staff) INTERROGATORY #74 List 1

Interrogatory

Issue 4.2
Are the proposed 2009 and 2010 levels of Shared Services and Other Capital expenditures appropriate?

Reference:
a) ExhD1/Tab3/Sched7/pp 1-3 &Table 1(p 2)
b) Proceeding EB-2005-0501, ExhD1/Tab3/Sched5/pp 15-17&Table 6(p 15)

Preamble:

- In Reference a), Table 1(p 2), show the following "Total Capital Costs" in $ Millions for the Cornerstone project as shown below:

	Historic	Bridge	Test Years	
	2007	**2008**	**2009**	**2010**
Total Capital Cost in $ Millions	63.6	130.6	100.3	63.5

- In Reference a), p 1 (lines 11-14) it is also stated in part that: " ***Phase 1*** *(Completed June 2008)….*"

- In Reference b), Table 6 (p 15), showed a forecast for the Cornerstone project for the two Test years 2007, and 2008 as follows:

	Historic	Bridge	Test Years	
	2005	**2006**	**2007**	**2008**
Capital Expenditures in $ Millions	0	0	102	28

- In Reference b), page 17(lines 18-24), it is also stated in part that: *"**Phase 1** - …..The EAM initiative has an estimated capital cost of $130 million in the period from 2007 to 2008…"*

Questions:

(i) Please indicate what was the actual cost of "Phase 1" of the Cornerstone project, and provide an explanation of the variance between the actual cost and the forecasted cost of $ 130 Million as outlined in Reference b).

(ii) Please provide the forecast cost of Phase 2 and Phase 3 of the Cornerstone project as described in Reference a), p 1 where Phase 2 is expected to be in Service in Q3, 2009 and Phase 3 is expected to be in service in Q4, 2010.

Response

(i) Actual 2008 OM&A and capital costs will be provided in a mid-February, 2009 update to the EB-2008-0272 evidence.

The forecast total capital cost of the Cornerstone – Phase 1 project as provided in EB-2008-0272 is $112.4 million as shown in the table below. This is $17.6 million less than the forecast of $130 million as presented in EB-2006-0501 Exhibit D1, Tab3, Schedule 5, and is largely attributed to successful project management, tight scope control and timely roll-out of the project.

Capital Expenditures in $ Millions

	Historic 2007	Bridge 2008	Total	Tx Portion 2007	Tx Portion 2008	Total
Cornerstone Phase 1 (EB-2006-0501)	102	28	130	57.0	15.8	72.8
Cornerstone Phase 1 (EB-2008-0272)	63.6	48.8	112.4	35.2	27.2	62.4
Variance	**-38.4**	**20.8**	**-17.6**	**-21.8**	**11.4**	**-10.4**

(ii) The forecast capital costs for Cornerstone Phases 1, 2 and 3 that total to numbers shown in Reference a), Table 1(p 2), and provided in the Investment Summary Documents for Phases 2 and 3 in Exhibit D2, Tab2, Schedule 3 Pages 73-74, are shown in the table below.

Capital Expenditures in $ Millions

	Historic 2007	Bridge 2008	Test Years 2009	Test Years 2010	Total
Cornerstone Phase 1	63.6	48.8	0	0	112.4
Cornerstone Phase 2	0	54.6	82.1	42.7	179.4
Cornerstone Phase 3	0	27.2	18.2	20.8	66.2
Total	**63.6**	**130.6**	**100.3**	**63.5**	**358.0**

Ontario Energy Board (Board Staff) INTERROGATORY #75 List 1

Interrogatory

Issue 4.3
Are the amounts proposed for rate base in 2009 and 2010 appropriate?

Reference: a) ExhD1/Tab3/Sched3/pp 33-35/Table2, Table 3 &Table 4
b) ExhD1/Tab1/Sched2/p 1/Table 1

Preamble:
There is need to reconcile the results in Reference a) with those presented in Reference b) for the "Development Capital Additions".

From Reference a), the Table below lists those "Development" projects that are categorized as either Category 1 or Category 2 and identifies the amount of investment that, once approved by the Board, can be included in the Rate Base in 2009 and 2010.

			Development Capital in $ Millions		
		In-Service	Gross	Rate Base Amounts	
Item #	Investment Description for Categories 1 & 2	Year	Total Cost	2009	2010
D1	Hydro One-Hydro Quebec	Mid 2009	122.8	122.8	0
D2	500 kV Bruce-Milton	Mid/09-Late/11	619.8	0.0	0
D3	Seven Cap.Banks-Southwestern Ontario	Late 2009	56.5	56.5	0
D4	Bruce Special Protection System	Mid 2010	5.8	0.0	5.8
D5	Cherrywood x Claireville - 500 kV Unbundle	Late 2010	107.3	0.0	107.3
D6	Static Var Compen.-Lakehead TS	Late 2010	22.5	0.0	22.5
D7	Static Var Compens.-Porcupine&Kirkland Lake	Late 2010	108.6	0.0	108.6
D8	Series Capacitors at Noble TS	Late 2010	47.2	0.0	47.2
D9	100 Mvar Shunt Capacitors - Algoma TS	Late 2010	9.7	0.0	9.7
D10	Two 75 Mvar Shunt Capacitors - Mississaugi TS	Late 2010	10.3	0.0	10.3
D15	Southern Beorgian Bay Trans. Reinforcement	Mid 2009	88	11.0	0
D16	Hurontario Station and Trans. Reinforcement	Mid 2010	43.5	0.0	43.5
D17	Trans.Reinforcement - Jim Yarrow TS	Mid 2011	49.1	0.0	0
D18	Woodstock Area Trans. Reinforcement	Mid 2011	69.8	0.0	0
D23	Kingston Gardiner TS (Add Capacity)	Late/08-Mid/09	8.5	8.5	0
D24	Holland TS (Build new TS & Line Connection)	Mid 2009	26.2	26.2	0
D25	Goreway TS (New Second DESN in the TS)	Mid 2010	14.8	0.0	14.8
D26	Vansickle TS (Increase Capacity)	Mid 2010	4.7	0.0	4.7
D27	Churchill MeadowTS-New TS&Line Connection	Late 2010	21.3	0.0	21.3
D28	Glendale TS(Increase Capacity)	Late 2010	3.2	0.0	3.2
D29	Dunnville TS (Increase Capacity	Late 2010	0.8	0.0	0.8
	TOTAL		1440.4	225.0	399.7

Clarification:

Please review the Table above, and provide explanation in regard to the variances for the Development Capital category that are eligible to be added to Rate Base for the two years 2009 and 2010 between the two References:

- the amount of $ 225.0 Million for 2009 and $ 399.7 Millions for 2010 in the above Table (Extracted from Reference a); and
- the amounts from Reference b) which show $347.9 Million for 2009 and $527.6 Million for 2010.

Response

Hydro One has made corrections to the table provided. Please see the corrected table below with the corrections highlighted.

			Development Capital in $Million		
		In-Service		Rate Based Amount	
Item #	Investment Description for Categories 1 & 2	Year	Gross Total Cost	2009	2010
D1	Hydro One-Hydro Quebec	Mid 2009	$122.8	$122.8	$0
D2	500 kV Bruce-Milton	Mid/10-Late/11	619.8	0	100.0
D3	Seven Cap.Banks-Southwestern Ontario	Late 2009	56.5	56.5	0
D4	Bruce Special Protection System	Mid 2010	5.8	0	5.8
D5	Cherrywood x Claireville - 500 kV Unbundle	Late 2010	107.3	0	107.3
D6	Static Var Compen.-Lakehead TS	Late 2010	22.5	0	22.5
D7	Static Var Compens.-Porcupine&Kirkland Lake	Late 2010	108.6	0	108.6
D8	Series Capacitors at Noble TS	Late 2010	47.2	0	47.2
D9	100 Mvar Shunt Capacitors - Algoma TS	Late 2010	9.7	0	9.7
D10	Two 75 Mvar Shunt Capacitors - Mississaugi TS	Late 2010	10.3	0	10.3
D15	Southern Georgian Bay Trans. Reinforcement	Mid 2009	88	88	0

			Development Capital in $Million		
		In-Service		Rate Based Amount	
Item #	Investment Description for Categories 1 & 2	Year	Gross Total Cost	2009	2010
D16	Hurontario Station and Trans. Reinforcement	Mid 2010	43.5	0	43.5
D17	Trans.Reinforcement - Jim Yarrow TS	Mid 2011	49.1	0	0
D18	Woodstock Area Trans. Reinforcement	Mid 2011	69.8	0	0
D23	Kingston Gardiner TS (Add Capacity)	Late/08-Mid/09	14.3	8.5	0
D24	Holland TS (Build new TS & Line Connection)	Mid 2009	26.2	26.2	0
D25	Goreway TS (New Second DESN in the TS)	Mid 2010	24.6	0	14.8
D26	Vansickle TS (Increase Capacity)	Mid 2010	16.3	0	4.7
D27	Churchill MeadowTS-New TS&Line Connection	Late 2010	24	0	21.3
D28	Glendale TS(Increase Capacity)	Late 2010	13.2	0	3.2
D29	Dunnville TS (Increase Capacity	Late 2010	8.6	0	0.8
	Total		$1,488.1	$302.0	$499.7

The 2009 and 2010 totals of $302 million and $499.7 million respectively shown in the table above consist of capital projects in excess of $3M, whereas the 2009 and 2010 in-service additions of $347.9 million and $527.6 million shown in Reference b) (Table 1 in Exhibit D1, Tab 1, Schedule 2) reflects all capital projects, regardless of size.

As a further note of clarification with respect to the corrected table above, please note that the Total Gross Cost of $1,488.1 is obtained by:

• Adding Rate Base Amount 2009	302.0
• Adding Rate Base Amount 2010	499.7
• Adding Rate Base Amount 2011	638.7 (not shown above)
• Adding back Capital Contributions	47.7
• Total Gross Cost	1,488.1

Ontario Energy Board (Board Staff) INTERROGATORY #76 List 1

Interrogatory

Issue 4.3
Are the amounts proposed for rate base in 2009 and 2010 appropriate?

Reference: a) ExhD2/Tab2/Sched1/p.1
b) ExhD1/Tab1/Sched2/p 1/Table 1

Preamble:
There is a need to reconcile the results in Reference a) with those presented in Reference b) for the "Sustaining Capital Additions".

Clarification:
Please provide explanation in regard to the variance for the Sustainment Capital category to be added to Rate Base for the two years 2009 and 2010 between the two References:

- the amount of $ 279.9 Million for 2009 and $ 321.6 Millions for 2010 as shown in Reference a); and
- the amounts from Reference b) which show $315.7 Million for 2009 and $319.5 Million for 2010.

Response

The information contained in the two references present two very different sets of information such that a calculation and discussion of "variances" between the two is not meaningful.

Exhibit D2-2-1 (Reference (a)) presents the capital expenditures view of capital programs and projects. Some of these programs and projects will be completed in the same year as the expenditure shown while others will be completed in future years.

Exhibit D1-1-2 (Reference (b)) presents the capital in-service additions view of capital programs and projects. In any particular year, capital additions consist of those programs and projects begun and finished in that year, as well as those started in previous years, accumulated as Work in Progress over the years, and completed in the year under consideration resulting in the multi-year accumulated costs being placed in-service, capitalized and added to Rate Base.

Ontario Energy Board (Board Staff) INTERROGATORY #77 List 1

Interrogatory

Issue 4.3
Are the amounts proposed for rate base in 2009 and 2010 appropriate?

Reference: a) ExhD2/Tab2/Sched1/p.2
b) ExhD1/Tab1/Sched2/p 1/Table 1

Preamble:
There is need to reconcile the results in Reference a) with those presented in Reference b) for the "Operations Capital Additions".

Clarification:
Please provide explanation in regard to the variance for the Operations Capital category to be added to Rate Base for the two years 2009 and 2010 between the two References:

- the amount of $ 18.2 Million for 2009 and $ 28.9 Millions for 2010 as shown in Reference a); and
- the amounts from Reference b) which show $19.6 Million for 2009 and $24.2 Million for 2010.

Response

The information contained in the two references present two very different sets of information such that a calculation and discussion of "variances" between the two is not meaningful.

Exhibit D2-2-1 (Reference (a)) presents the capital expenditures view of capital programs and projects. Some of these programs and projects will be completed in the same year as the expenditure shown while others will be completed in future years.

Exhibit D1-1-2 (Reference (b)) presents the capital in-service additions view of capital programs and projects. In any particular year, capital additions consist of those programs and projects begun and finished in that year, as well as those started in previous years, accumulated as Work in Progress over the years, and completed in the year under consideration resulting in the multi-year accumulated costs being placed in-service, capitalized and added to Rate Base.

Ontario Energy Board (Board Staff) INTERROGATORY #78 List 1

Interrogatory

Issue 4.3
Are the amounts proposed for rate base in 2009 and 2010 appropriate?

Reference: a) ExhD2/Tab2/Sched1/p.2
b) ExhD1/Tab1/Sched2/p 1/Table 1

Preamble:
There is need to reconcile the results in Reference a) with those presented in Reference b) for the "Shared Services and Other Costs".
It is noted that:

- In Reference a) the capital investment categorized as "Shared Services and Other Costs" is $ 92.4 Million in 2009 and 64.9 Million in 2010; and
- In Reference b), there is a category named "Other" which list $ 110.8 Million for 2009 and 90.5 Million for 2010.

Clarification:

(i) Please clarify whether the two categories outlined above are the same
(ii) If the response to (i) indicates that they are the same, please provide explanations of the variances outlined above for the two years, 2009 and 2010.
(iii) If the response to (i) indicates that the two categories are different, please provide where in the submission is the "In-service Capital Additions" for "Shared Services and Other Costs" is included.

Response

(i) The two categories are the same, in that they both refer to the same set of projects.

(ii) The information contained in the two references present two very different sets of information about this category such that a calculation and discussion of "variances" between the two is not meaningful.

Exhibit D2-2-1 (Reference (a)) presents the capital expenditures view of capital programs and projects. Some of these programs and projects will be completed in the same year as the expenditure shown while others will be completed in future years.

Exhibit D1-1-2 (Reference (b)) presents the capital in-service additions view of capital programs and projects. In any particular year, capital additions consist of those programs and project begun and finished in that year, as well as those started in previous years, accumulated as Work in Progress over the years, and completed in the year under consideration resulting in the multi-year accumulated costs being placed in-service, capitalized and added to Rate Base.

(iii) Not Applicable

Ontario Energy Board (Board Staff) INTERROGATORY #79 List 1

Interrogatory

Issue 5.1
Are the proposed amounts and disposition for each of the deferral and variance accounts appropriate?

Reference: Ref: ExhF1/Tab1/Sch1/p3
Preamble:
Hydro One indicates that the OEB Cost Assessment Differential Account was "established based on the Board's Decision on Hydro One's Transmission Rate for 2007 and 2008 (EB-2006-0501) which accepted the establishment of the OEB Cost Assessment Differential Account."
Question:
Please provide the specific reference from the EB-2006-0501 decision that showed the acceptance of the establishment of this account.

Response

The OEB Cost Assessment Differential Account was one of the four Variance Accounts requested in EB-2006-0501, Exhibit F1, Tab 3, Schedule 1 (along with Tax Rate Changes, Transmission System Code Changes and Pension Cost Differential variance accounts).

In the Settlement Proposal Decision for EB-2006-0501 dated April 18, 2007, page 6, the Board accepted the settlement proposal to establish four new variance accounts. Therefore, based on this decision Hydro One Transmission established the OEB Cost Assessment Differential variance account.

Ontario Energy Board (Board Staff) INTERROGATORY #80 List 1

Interrogatory

Issue 5.1
Are the proposed amounts and disposition for each of the deferral and variance accounts appropriate?

Reference: Ref: ExhF1/Tab1/Sch1
Hydro One is applying for disposition of three deferral and variance accounts. Provide the information as shown in the attached continuity schedule for these accounts. In the continuity schedule, please breakout the sub-accounts for 1508. Please note that forecasting principal transactions beyond December 31, 2007 and the accrued interest on these forecasted balances and including them in the attached continuity schedule is optional.

[Note: Excel spreadsheet continuity schedule attached]

Response

Please see the attached Excel spreadsheet.

SHEET 1 - Regulatory Assets - Continuity Schedule

NAME OF UTILITY		**LICENCE NUMBER**	ED-XXXX-XXXX
NAME OF CONTACT		**DOCID NUMBER**	EB-200X-XXXX
E-mail Address			
VERSION NUMBER	v3.0	**PHONE NUMBER**	
Date		**(extension)**	

Enter appropriate data in cells which are highlighted in yellow only.
Enter the total applied for Regulatory Asset amounts for each account in the appropriate cells below:
Debits should be recorded as positive numbers and credits should be recorded as negative numbers.
Repeat cells going across as necessary for each year in application

		2006									2007										
Account Description	**Account Number**	**Opening Principal Amounts as of Jan-1-06** [1]	**Transactions (additions) during 2006, excluding interest and adjustments** [6]	**Transactions (reductions) during 2006, excluding interest and adjustments** [6]	**Adjustments during 2006 - instructed by Board** [2]	**Adjustments during 2006 - other** [3]	**Closing Principal Balance as of Dec-31-06**	**Opening Interest Amounts as of Jan-1-06**	**Interest Jan-1 to Dec31-06**	**Closing Interest Amounts as of Dec-31-06**	**Opening Principal Amounts as of Jan-1-07**	**Transactions (additions) during 2007, excluding interest and adjustments** [6]	**Transactions (reductions) during 2007, excluding interest and adjustments** [6]	**Adjustments during 2007 - instructed by Board** [2]	**Adjustments during 2007 - other** [3]	**Transfer of Board-approved amounts (if applicable)**	**Closing Principal Balance as of Dec-31-07**	**Opening Interest Amounts as of Jan-1-07**	**Interest Jan-1 to Dec31-07**	**Transfer of Board-approved amounts (if applicable)**	**Closing Interest Amounts as of Dec-31-07**
Tax Rate changes	1592						$ -			$ -	$ -	$ (3,483,600)					$ (3,483,600)	$ -	$ (1,982)		$ (1,982)
OEB Cost Assessment Differential	1508						$ -			$ -	$ -	$ (922,696)					$ (922,696)	$ -	$ (22,070)		$ (22,070)
Pension Cost Differential	2405						$ -			$ -	$ -	$ (1,285,001)					$ (1,285,001)	$ -	$ (19,024)		$ (19,024)
							$ -			$ -	$ -						$ -	$ -			$ -
Totals		$ -	$ -		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (5,691,297)		$ -	$ -	$ -	$ (5,691,297)	$ -	$ (43,076)	$ -	$ (43,076)

SHEET 1 - Regulatory Assets - Continuity Schedule

NAME OF UTILITY
NAME OF CONTACT
E-mail Address
VERSION NUMBER v3.0
Date

		2008 Projected									2009 Projected						
Account Description	**Account Number**	**Opening Principal Amounts as of Jan-1-08**	**Transactions (additions) during 2008, excluding interest and adjustments [6]**	**Transactions (reductions) during 2008, excluding interest and adjustments [6]**	**Adjustments during 2008 - instructed by Board [2]**	**Adjustments during 2008 - other [3]**	**Closing Principal Balance as of Dec-31-08**	**Opening Interest Amounts as of Jan-1-08**	**Interest Jan-1 to Dec31-08**	**Closing Interest Amounts as of Dec-31-08**		**Projected Interest on Dec 31 -08 balance from Jan 1, 2009 to June 30, 2009 [9]**	**Claim before Forecasted Transactions**		**Forecasted Transactions, Excluding Interest from Jan 1, 2009 to June 30, 2009**		**Projected Interest from Jan 1, 2009 to June 30, 2009 on Forecasted Transx (Excl Interest) from Jan 1, 2009 to June 30, 2009**
Tax Rate changes	1592	$ (3,483,600)	$ (6,221,004)				$ (9,704,604)	$ (1,982)	$ (241,012)	$ (242,994)		$ (162,107)	$ (10,109,705)		$ (3,715,498)		$ (25,477)
OEB Cost Assessment Differential	1508	$ (922,696)	$ (2,041,901)				$ (2,964,597)	$ (22,070)	$ (74,631)	$ (96,701)		$ (49,521)	$ (3,110,819)		$ (1,097,410)		$ (10,676)
Pension Cost Differential	2405	$ (1,285,001)	$ 1,159,024				$ (125,977)	$ (19,024)	$ (70,137)	$ (89,161)		$ (2,409)	$ (217,547)		$ -		$ -
		$ -					$ -	$ -		$ -			$ -				
Totals		$ (5,691,297)	$ (7,103,881)		$ -	$ -	$ (12,795,178)	$ (43,076)	$ (385,780)	$ (428,856)	$ -	$ (214,037)	$ (13,438,071)	$ -	$ (4,812,908)	$ -	$ (36,153)

Ontario Energy Board (Board Staff) INTERROGATORY #81 List 1

Interrogatory

Issue 5.1
Are the proposed amounts and disposition for each of the deferral and variance accounts appropriate?

Reference: Ref: ExF1/Tab1/Sch1
Questions:

Regarding the Tax Rate Changes Account, did Hydro One include the impact of the repeal of the Large Corporation Tax (LCT) in this account? If not, why not? To what account did Hydro One book these amounts in the period January 1st 2006 to the repeal of the LCT?

Response

In 2006 Hydro did not book the impact of the repeal of the Large Corporation Tax (LCT) in a deferred account.

In the OEB's Transmission Decision with Reason for EB-2006-0501 any earnings over the approved return was subject to an earnings sharing mechanism. Any variances due to tax rate changes, such as the LCT rate change were reflected in the earnings subject to the revenue sharing mechanism, and 50% of the benefit was returned to customers

Any changes to the LCT or other federal taxes occurring in 2007 and onwards, that are not included in the revenue requirement calculation are tracked in the Tax Rate Changes variance account.

Ontario Energy Board (Board Staff) INTERROGATORY #82 List 1

Interrogatory

Issue 5.1
Are the proposed amounts and disposition for each of the deferral and variance accounts appropriate?

Reference: Ref: ExhF1/Tab1/Sch1
Preamble: Usual practice in the electricity sector is to use audited numbers for the last fiscal year as the basis for balances in the deferral and variance accounts for disposition, with interest forecasted up to the start of the new rate year.
Questions:

a) Please provide the regulatory precedent for principal transactions being forecasted beyond December 31, 2007 for accounts requested for disposition.
b) Please recalculate the appropriate rate rider schedules using the December 31, 2007 balances with interest forecasted to June 30, 2009.

Response

a) The regulatory precedent for principal transactions being forecast can be found in RP-2005-0020 (EB-2005-0378) Hydro One Networks Inc., Electricity Distribution Rates 2006. In the Hydro One Distribution submitted evidence, Regulatory Asset balances were projected to April 30, 2006. Those projected balances were approved by the Board on April 12, 2006 (subject to interest rate changes).

b) Hydro One is not requesting a rate rider but is deducting the amount from our Revenue Requirement as noted on Exhibit E1, Tab1, Schedule 1, Table 2, line 8.

The following schedule shows the actual December 31, 2007 balances of the deferral and variance accounts with December 31, 2008 and to June 30, 2009 forecast interest added. Interest is calculated at the OEB prescribed interest rate:

in $M	**Dec. 31, 2007**	**Dec. 31, 2008**	**June 30, 2009**
Tax Rate Changes	(3.5)	(3.6)	(3.7)
OEB Cost Assessment Differential	(0.9)	(1.0)	(1.0)
Pension Cost Differential	(1.3)	(1.4)	(1.4)
Total Regulatory Assets for Approval	**(5.7)**	**(6.0)**	**(6.1)**

The following schedule shows the disposition of the December 31, 2007 actual balances with interest forecast to June 30, 2009 at the applicable prescribed OEB Interest Rates:

in $M	**2009**	**2010**	**2011**	**2012**	**2013**	**Total**
Revenue reduction per above	(0.8)	(1.5)	(1.5)	(1.5)	(0.8)	(6.1)
Requested Revenue Reduction per F2 -1 -2	(2.3)	(4.6)	(4.6)	(4.6)	(2.3)	(18.3)
Increased Rates Revenue Requirement	1.5	3.1	3.1	3.1	1.5	12.2

Ontario Energy Board (Board Staff) INTERROGATORY #83 List 1

Interrogatory

Issue 5.1
Are the proposed amounts and disposition for each of the deferral and variance accounts appropriate?

Reference: Ref: ExhF1/Tab2/Sch1
Preamble: Hydro One is proposing to refund the deferral and variance accounts to customers over a period of 4 years.
Question:

a) Why is Hydro One proposing a four year recovery period, seeing as the company may be rebased with new rates in place in January 2011?

b) Please provide a schedule identifying the rate riders associated with the disposition of the deferral and variance accounts over a one, two and three year periods. Please show all relevant calculations.

Response

a) Hydro One Transmission is proposing a four year recovery period to maintain consistency with recovery periods approved for other Regulatory Accounts within the Company's electricity Transmission and Distribution businesses, such as the 2007-2008 Transmission Rate Proceeding (EB-2006-0501), the 2006 Distribution Rate Proceeding (RP-2005-0020/ EB-2005-0378) and the 2004 Regulatory Assets Review Proceeding (RP-2004-0117/0118). A four year recovery helps to smooth the customer impact and interest is applied to the principle balance to appropriately reflect the time value of money for the customer and the Company.

b) The following schedule shows the disposition over a one, two and three year period, with the first and final years covering a six month period only:

in $M	**2009** (July – Dec)	**2010** (Jan – Dec)	**2011** (Jan – Dec)	**2012** (Jan – June)	**Total**
1 year disposition period *	(9.2)	(9.1)			(18.3)
2 year disposition period **	(4.6)	(9.2)	(4.5)		(18.3)
3 year disposition period ***	(3.1)	(6.1)	(6.1)	(3.0)	(18.3)

* (18.3)M / 12 months * 6 months
** (18.3)M / 24 months * 6 months or 12 months as appropriate
*** (18.3)M / 36 months * 6 months or 12 months as appropriate

Ontario Energy Board (Board Staff) INTERROGATORY #84 List 1

Interrogatory

Issue 5.2: Is the proposed continuation of the deferral/variance accounts appropriate?

Reference: Ref: ExhF1/Tab1/Sch2
Preamble: Hydro One proposes to continue the Pension Cost Deferral Account but does not mention the OEB Cost Assessment Differential Account or Tax Rate Changes Account.
Question:
Does Hydro One also propose to continue the latter two accounts? If so, please provide justification, and details of the accounts such as the proposed journal entries to be recorded.

Response

The OEB Cost Assessment Differential Account and the Tax Rate Changes Account were two of the four Variance Accounts Requested in EB-2006-0501, Exhibit F1, Tab 3, Schedule 1 (along with Transmission System Code Changes and Pension Cost Differential variance accounts).

In the Settlement Proposal Decision for EB-2006-0501 dated April 18, 2007, page 6, the Board accepted establishment of four new variance accounts. Therefore, based on this decision Hydro One Transmission established the OEB Cost Assessment Differential variance account and the Tax Rate Changes Account. Specific end dates for these accounts were not identified when the creation of these accounts was requested. Hydro One Transmission does propose to continue these two accounts with the details of the accounts as follows:

OEB Cost Assessment Differential Account: This account will track the difference between the annual OEB Cost Assessment and the amount for this expenditure approved by the OEB as part of the current Revenue Requirement.

Illustrative journal entries to be posted on a quarterly basis are as follows:

Debit Revenue		XX	
	Credit OEB Cost Assessment variance		XX

(To record the variance between the OEB Cost Assessment and OEB costs in the approved revenue requirement if assessment is less than amount in approved budget.)

Tax Changes Account: Consistent with the Board communiqué of December 2005 (to LDC's), the Tax Changes account will capture the tax impact of the following differences:

- differences that result from a legislative or regulatory change to the tax rates or rules, and
- differences that result from a change in, or a disclosure of, a new assessing or administrative policy that is published in the public tax administration or interpretation bulletins by relevant federal or provincial tax authorities.

The proposed journal entries done on a monthly basis are as follows:

Debit	Revenue		XX	
	Credit	Tax changes variance		XX

(To record a variance for the tax impact arising from changes in tax rates and regulations from those included in the approved revenue requirement.)

Ontario Energy Board (Board Staff) INTERROGATORY #85 List 1

Interrogatory

Issue 5.3 Are the proposed new Deferral/Variance Accounts appropriate?

Reference: Ref: ExhF1/Tab1/Sch2/p4
Preamble: Hydro One indicates that the Transmission System Code and Cost Responsibility Changes Account was previously approved by the Board.
Question:
Please provide the specific reference of this Board decision that showed the approval of this account.

Response

The Transmission System Code and Cost Responsibility Changes Account was one of the four Variance Accounts Requested in EB-2006-0501, Exhibit F1 Tab 3 Schedule 1 (along with Tax Rate Changes, OEB Cost Differential and Pension Cost Differential variance accounts).

In the Settlement Proposal Decision for EB-2006-0501 dated April 18, 2007, page 6, the Board accepted the settlement proposal to establish four new variance accounts. Therefore, based on this decision Hydro One Transmission established the Transmission System Code and Cost Responsibility Changes variance account.

Ontario Energy Board (Board Staff) INTERROGATORY #86 List 1

Interrogatory

Issue 5.3 Are the proposed new Deferral/Variance Accounts appropriate?

Reference: Ref: ExhF1/Tab1/Sch2
Preamble: Hydro One is requesting for new deferral/variance accounts related to the IPSP and Other Preliminary Planning Costs and related to Transmission System Code and Cost Responsibility Changes.
Questions:

a) What is the regulatory precedent for the collection of each of the identified costs proposed to be included in these deferral accounts?
b) What account numbers does Hydro One propose to use in the USoA?
c) Can Hydro One provide the expected journal entries to be recorded?
e) If the costs or fees are not known, what would be the basis of the approval to record these amounts in a deferral account?
f) What new or additional information is available that would improve the Board's ability to make a decision on this request?

Response

Please note that there is no part d)

a) Hydro One can provide the following regulatory precedents for these requests:

IPSP AND OTHER PRELIMINARY PLANNING COSTS

On August 13, 2004, in Decision 2004-067, the Alberta Utilities Commission ("AUC") authorized (then) EPCOR Distribution Inc. ("EDI") to establish a deferral account for the 2004 test year, to track costs incurred in respect of the Alberta Electric System Operator ("AESO"). Such costs include EDI's operating and/or capital costs relating to AESO system initiatives, which EDI had argued were undefined and uncertain. Accordingly, the company was unable to forecast on a reasonable basis, the amount of AESO-directed capital projects it would undertake during the test years. The AUC considered it "appropriate to establish a deferral account for these costs since they are outside the control of EDI management and may be significant and difficult to forecast" (Decision 2004-067, page 86).

In subsequent proceedings, EDI (later EPCOR Distribution and Transmission Inc., or "EDTI") stated that it continued to have little, if any control over expansion or enhancement projects which result from the AESO's transmission planning process. The AUC accepted this reasoning and in Decision 2006-054 (June 15, 2006), authorized EDTI to retain this deferral account for 2005 and 2006 test years to capture the difference between forecast and actual expenditures on projects which are directed by the AESO. In Decision 2008-125 (Dec. 3, 2008), the AUC again approved the continuation of this deferral account, having found no material change in circumstances which would necessitate its removal. As a result, this account will continue through the company's 2009 rate year.

Hydro One's under a similar construct in its role as a transmitter when delivering projects that are identified, planned and required by the Ontario Power Authority ("OPA"), as EDTI has with the AESO. Hydro One is currently undertaking preliminary work, which is identified in the IPSP but is yet to be approved. The company believes that it is prudent to undertake this work to meet the required in-service dates identified by the OPA, but, it faces risks that are arguably greater than those faced by EDTI, as the in-service dates are contingent on a yet uncertain IPSP approval. In the event that approval of individual projects in the IPSP may take some time or not be given at all, Hydro One would face a revenue loss. The deferral account is intended to mitigate this risk.

TRANSMISSION SYSTEM CODE AND COST RESPONSIBILITY COSTS

Hydro One wishes to clarify that its request in Exhibit F1, Tab 1, Schedule 2, Item 4.0, is not for a new account, but rather to *continue* the deferral account related to the Transmission System Code.

The most relevant regulatory precedent was established when this deferral account was originally approved by the Board's Decision on Hydro One's 2007-2008 Transmission rates (EB-2006-0651, dated August 16, 2007). The Company in its submission, had stated that, as new connection procedures were reviewed and approved by the Board, previous interpretations of the Code would be questioned. In its Decision, the Board accepted Hydro One's position that it needed the ability to recover through rates, costs that may be shifted from customers to the Company as a result of the Board's changes in interpretation of the Code.

Another precedent is the Ontario Energy Board's February 1995 approval of the establishment of the Class Action Suit Deferral Account ("CASDA"), on behalf of Enbridge Gas Distribution Inc. ("Enbridge"). In this case the Board has acted to hold a utility harmless where a practice that the utility had established pursuant to a Board order is overturned by a subsequent decision, resulting in financial consequences to the company. The CASDA was implemented to record costs arising from the company's defence in a class action suit respecting late payment penalties. Enbridge had argued that such costs should be recoverable from rate-payers, as they were incurred when defending late payment penalties established by Board orders, which were subsequently found invalid. The Board agreed with Enbridge's argument. Since the establishment of this account, the Board approved its continuation and the clearance of balances on several occasions. Its most recent authorization to clear the account was given on February 4, 2008, in Decision EB-2007-0731. Similarly, Hydro One's deferral account is intended to ensure that the changes to cost responsibility policies do not adversely impact the company's financial results.

Subsequent to this Decision and through the remainder of 2007 and 2008, Hydro One did not incur any costs related to changes in connection procedures, so the account was not opened. The need for this account still exists, however, and may in fact be greater. For example, the Board is now reviewing the Code's provisions for assigning cost responsibility for enabler lines. The Board's proposal may involve transmitters making investments as part of the Transmitter Designation process, and the mechanism for recovery of such costs is not yet clear. Furthermore, policy reviews of cost responsibility for transmission facilities related to load connections and distribution-connected generation also will be undertaken. Hydro One continues to have a concern that re-interpretations of the Code will reduce its capability to recover future costs either directly or through capital contributions from customers. It is also concerned that re-interpretations could result in potential refunds of past contributions, which could be significant.

b) Hydro One proposes to record its expenditures related to both these deferral accounts in new sub-accounts to be established within USofA 1508 "Other Regulatory Assets."

c) The following journal entries are illustrative -

Re. IPSP planning costs:

<u>Entry 1</u>

Dr. OM&A	XX	
Cr. A/P		XX

Initial entry to record incurrence of planning costs.

<u>Entry 2</u>

Dr. Deferred IPSP expenditures	XX	
Cr. OM&A		XX

To reclassify expense to deferral account.

Re. Transmission System Code & Cost Responsibility Changes

<u>Entry 1</u>

Dr.	Contributed capital	XX	
	Cr. Cash		XX

To record refund of contributed capital due to change in TSC or change in cost responsibility

Entry 2

Dr.	TSC & cost responsibility variance	XX	
	Cr. TSC & cost responsibility variance - contra		XX

To record revenue requirement impact of refund in a variance account

e) Hydro One has estimated that costs of $19.2 million will be incurred for the IPSP pre-planning work during the test years, as noted in Exhibit F1, Tab 1, Schedule 2, page 1, line 26. Hydro One believes that all incremental costs associated with projects identified in the IPSP should be recorded in the deferral account.

The Company does not yet have an estimate of the amounts which would be incurred as a result of the review by the Board or its staff of the relevant portions of the Transmission System Code and their application by Hydro One. It believes that in potential cases where capital contributions must be refunded as a result of re-interpretations of the Code, the amount recorded in deferral accounts should allow for recovery of all of the revenue retroactive to the date when the capital contribution should have been applied to rate base.

f) As noted in a) above, Hydro One wishes to clarify its request for a deferral account for Transmission System Code and Cost Responsibility Costs. This is a request to continue the current approved account, not create a new one.

Hydro One does not have any new or additional information related to its request for a deferral account for IPSP-related costs.

Ontario Energy Board (Board Staff) INTERROGATORY #87 List 1

Interrogatory

Issue 6.1
Would it be appropriate to make changes to cost allocation in response to the study submitted on line connection costs for customers directly connected to networks stations?

Reference: a) ExhG1/Tab1/Sch1/p.2
b) ExhG1-3-1/Attachment 1

Preamble:
In ExhG1/Tab1/Sch1/p.2 it is stated that:
"Per the Settlement Agreement approved by the Board under EB-2006-0501, an internal study was done to investigate an alternative definition of the Line Connection assets at Network Stations….Hydro One Transmission is not recommending any changes to the currently Board approved Cost Allocation and Charge Determinants methodology."

Question:
Please state why Hydro One Transmission did not recommend any changes to the currently Board approved cost allocation and charge determinants methodology.

Response

The currently approved cost allocation methodology was initially reviewed and approved by the Board in proceeding RP-1999-0044. At the EB-2006-0501 proceeding, the cost allocation and associated methodology was a settled issue with intervenors, who agreed that the status quo is appropriate. During the stakeholdering for the current Application, cost allocation was not raised by any party as an issue that merits further study or requires a change to the status quo.

An analysis of the estimated impacts from changes to the allocation of Line Connection costs, as detailed in Exhibit G1, Tab 3, Schedule 1, Attachment 1, shows the potential for significant bill impacts to a few customers, as described in response to Board Staff Interrogatory # 88. Given these estimated impacts, and the fact that cost allocation methodology is not an issue to intervenors, Hydro One Transmission is not proposing a change in the way Line Connection costs are recovered.

Hydro One is not recommending any changes to the current charge determinant methodology because the current approach is based on considerable evidence and the involvement of a wide range of stakeholders when the methodology was initially set in proceeding RP-1999-0044 and subsequently reviewed in EB-2006-0501, and there does not seem to be a consensus amongst stakeholders for making a change to the status quo.

Ontario Energy Board (Board Staff) INTERROGATORY #88 List 1

Interrogatory

Issue 6.1
Would it be appropriate to make changes to cost allocation in response to the study submitted on line connection costs for customers directly connected to networks stations?

Reference: a) ExhG1/Tab3/Sch1/p.4
b) ExhG1-3-1/Attachment 1/p.8

Preamble: In ExhG1/Tab 3/Schedule 1, p.4, it is noted that Hydro One's internal study on connection facilities terminating in Network Stations had identified bill impacts on transmission customers ranging from -1.4% to 330% on the transmission bill. Table 4 of Exhibit G1-3-1/Attachment 1/p.4 provides a breakdown of these impacts by customer group.

Question:
Please provide a more detailed breakdown of these bill impacts including the number of customers that would see bill impacts in excess of 10%, the type of customers these would be and an explanation as to why these impacts are occurring.

Response

Table 4 of Exhibit G1, Tab 3, Schedule 1, Attachment 1, has been partially re-produced below for impacts of greater than 10% on the estimated Transmission bill if Line Connection Charges were to be applied to those delivery points which are currently exempt. The impacts were done per Transmission Delivery Point and then aggregated by Customer Group. Further details on the number of customers and their delivery points have been added to the table.

Impact On Transmission Bill for 2009

Customer Group	**Scenario**		**Impacts greater than 10%**	
	Impacts	Range of Impacts	Customers	Tx Delivery Points
Directs	7.1%	2.6 to 330%	2	2
LDCs	6.2%	1.9 to 23%	4	9
Generators	6.9%	-1.4 to 7.8%	0	0

The large impact for the 2 Direct customers is based on the very large non-coincident peak demand as compared to their on-peak demand. Both Directs are currently only charged Network Charges and do not get Line (or Transformation) Connection Charges, which are based on their larger non-coincident peak demand.

The 4 LDCs which are projected to have impacts greater than 10% are currently only charged Network and Transformation for some of their delivery points. Under the Scenario, they would also be charged for Line Connection for these delivery points, which results in the increased impacts shown above.

Ontario Energy Board (Board Staff) INTERROGATORY #89 List 1

Interrogatory

Issue 6.1
Would it be appropriate to make changes to cost allocation in response to the study submitted on line connection costs for customers directly connected to networks stations?

Reference: a) ExhG1-3-1/Attachment 1/p.1
Preamble:
On p.1 of Exhibit G1-3-1/Attachment 1, it is stated that:

> *"A study was done to identify the possible Network assets used to connect delivery points at a Network Station for re-classification as Line Connection assets.""*

Question:
Please provide a copy of this study.

Response

The study description and its results are fully documented in the evidence provided in Attachment 1 of Exhibit G1, Tab 3, Schedule 1.

Ontario Energy Board (Board Staff) INTERROGATORY #90 List 1

Interrogatory

Issue 6.1
Would it be appropriate to make changes to cost allocation in response to the study submitted on line connection costs for customers directly connected to networks stations?

Reference: a) ExhG1-3-1/Attachment 1/p.3
Preamble:
On p.3 of Exhibit G1-3-1/Attachment 1, it is stated that:
"To determine the additional cost of a customer connection directly to a network station, the cost of connecting a load serving transformer station inside the fence of a network station (Option 2) was used as the configuration encompasses the majority of these connections. The cost would be in the range of $1 Million to $1.5 Million depending on the connection point and land requirements"

Question:

a) Please state whether any other definition of configuration costs was considered in the above context and if so why it was rejected. Please clarify what is meant by Option 2.

b) Please provide a more detailed explanation as to how the cost range of $1 to $1.5 million was determined.

Response

a) As noted in Exhibit G1, Tab 3, Schedule 1, Attachment 1, page 2, Section 3.0 the three configurations currently existing within Hydro One were considered in the study. For the purpose of estimating the impacts, the typical cost for connecting a load serving transformer station inside the fence of a network station was used as it is the most common configuration. Option 2 is when a load serving TS is built /located inside the fence of a Network station (section 3.2).

b) The cost range of $1 million to $ 1.5 million was arrived at by taking into consideration the following factors that would affect the cost of incorporating a load serving transformer station inside a Network Station:
   i) Location of TS in reference to high voltage supply circuits and/ or high voltage bus within Network Station
   ii) Extension and modification to high voltage connection point for incorporating the new TS
   iii) Isolating devices (breakers, motorized disconnect switches) required at the connection point
   iv) Additions/ modifications required to protection systems

Ontario Energy Board (Board Staff) INTERROGATORY #91 List 1

Interrogatory

Issue 6.1
Would it be appropriate to make changes to cost allocation in response to the study submitted on line connection costs for customers directly connected to networks stations?

Reference: a) ExhG1-3-1/Attachment 1/p.4/L 14-16
Preamble:
It is stated that:

> "*The total of 45 delivery points includes 2 Direct customers who are connected to their Network Station through their own lines, that based on this definition would now be levied Line Connection charges.*"

Question:

a) Please clarify whether or not the two Direct Customers each own their Network Station as well as the connecting lines
b) If the answer to a) is yes, please provide the rationale for Hydro One assuming that Line Connection charges are justified under such a scenario.

Response

a) No transmission connected customer owns a Network station as well as the connecting lines. Some customers, including the two Direct customers referenced, do own their own step down transformer station, which is not a Network station.

b) Not applicable

Building Owners and Managers Association of the Greater Toronto Area ("BOMA") and London Property Management Association ("LPMA") INTERROGATORY #1 List 1

Interrogatory

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

Ref: Exhibit B1, Tab 1, Schedule 1, page 1 - 2

a) What is the impact of a ten basis point change in the equity return on the overall revenue requirement in 2009? In 2010?

b) Please provide an update to the equity returns based on the most recently available *Consensus Forecast.* Please provide all data and calculations used for 2009 and 2010.

Response

a) If equity return were changed by ten basis points, revenue requirement in 2009 would change by $4.2M and revenue requirement in 2010 would change by $4.5M

b) Based on the ROE formula, outlined in Appendix B of the Cost of Capital report:
ROE = 9.35% + 0.75*(LCBF – 5.5%)
Where LCBF is the Long Canada Bond Forecast

Updated ROE for 2009 would be:
ROE = 9.35% + 0.75*(4.4% – 5.5%)
ROE = 8.53%

The application of ROE the formula for 2010 is:
ROE = 9.35% + 0.75*(5.05% – 5.5%)
ROE = 9.01%

The 30-year Long Canada Bond Forecast rates were calculated as follows:

	2009	2010
November 2008 *Consensus Forecast* for the 10 year Government of Canada Bond yield Average of 3 month out (3.7% Feb 09) and 12 month out (4.0% Nov 2009)	3.85%	
October 2008 Consensus Forecast (long term forecast page 28) of the 10 year Government of Canada Bond yield		4.50%
Average difference between 10 and 30 year Government of Canada bond yields during November 2008 - from the Bank of Canada website Series V39055 and Series V39056	0.55%	0.55%
Long Canada Bond Forecast	4.40%	5.05%

Building Owners and Managers Association of the Greater Toronto Area ("BOMA") and London Property Management Association ("LPMA")
INTERROGATORY #2 List 1

Interrogatory

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

Ref: Exhibit B1, Tab 1, page 2

Appendix B of the Cost of Capital Report states that "for May 1 rate changes, the ROE will be based on January data – effectively *Consensus Forecasts* published during that month and Bank of Canada data for all business days during the month of January". Hydro One is proposing rates changes effective July 1, 2009.

a) When is Hydro One proposing to change rates for the 2010 test year?

b) Given that Hydro One is proposing to change rates effective July 1 rather than May 1, should the ROE be based on a March *Consensus Forecasts* and Bank of Canada data for all business days in the month of March? If not, why not?

Response

a) Hydro One is proposing to change tariff rates on January 1, 2010

b) As stated in the December 20, 2006 Report of the Board, Hydro One's final ROE will be factored into rates using the Long Canada Bond Forecast based on *Consensus Forecasts* and Bank of Canada data three months in advance of the effective date for the rate change.

Building Owners and Managers Association of the Greater Toronto Area ("BOMA") and London Property Management Association ("LPMA") INTERROGATORY #3 List 1

Interrogatory

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

Ref: Exhibit B1, Tab 1, Schedule 1, page 2

a) What is the impact of a ten basis point change in the short-term debt rate on the overall revenue requirement in 2009? In 2010?

b) Please provide an update to the short term debt rates based on the most recently available *Consensus Forecast*.

d) Please confirm that Hydro One accepts the use of a short term debt rate that is calculated as the average of the 3-month bankers acceptance rate plus a fixed spread of 25 basis points, as published on the Bank of Canada's website, for all business days of the same month as used for determining the ROE.

Response

Please note that there is no Question 3 c).

a) If the short-term debt rate were changed by ten basis points, revenue requirement in 2009 would change by \$0.3M and revenue requirement in 2010 would change by \$0.3M

b)

	2009
November 2008 *Consensus Forecast* for the 3 month T-bill yield Average of 3 month out (1.7% Feb 09) and 12 month out (2.2% Nov 2009)	1.95%
Average difference between 3 month T-bill and 3 month Bankers Acceptance yields during November 2008 - from the Bank of Canada website Series V39065 and Series V39071	0.59%
3 month Bankers Acceptance forecast rate	2.54%
Plus fixed spread of 25 basis points	0.25%
Forecast Deemed Short term debt rate	2.79%

The long term *Consensus Forecast*, which is provided semi-annually in April and October, does not contain a forecast of Canadian short term interest rates (ie. T-bill). Hence a forecast of the deemed short term debt rate for 2010 based on *Consensus Forecasts* is not available yet.

d) Confirmed

Building Owners and Managers Association of the Greater Toronto Area ("BOMA") and London Property Management Association ("LPMA") INTERROGATORY #4 List 1

Interrogatory

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

Ref: Exhibit E1, Tab 1, Schedule 2, Table 1

a) Please provide the most recent year-to-date figures for each of the four sources of revenue in the 2008 bridge year column.

b) Please provide the corresponding year-to-date figures for each of the four sources of revenue in the 2007 historical year.

c) Please confirm that the 2008 bridge forecast is approximately $10 million higher than the Board approved figure for 2008 shown in Table 2 of Exhibit E1, Tab 1, Schedule 1. Please provide explanations for the increase as compared to the Board approved figure.

Response

a) and b) As noted in our response in Exhibit I, Tab 1, Schedule 10, Hydro One plans to updated evidence for actual 2008 year end results prior to the start of the oral hearing. At that time, Table 1 of Exhibit E1, Tab 1, Schedule 2 will be updated**.**

c) At the time that evidence was prepared, the May forecast provided an estimated revenue of $34.4M, which was approximately $10M higher than the Board-approved figure shown in Table 2 of Exhibit E1, Tab 1, Schedule 1.

Variances from budget for external revenue generally resulted from higher than planned demand work, which resulted from external parties undergoing growth in their own work programs which required Hydro One's participation. In performing this external work, Hydro One ensured the execution of its own growing work programs was not compromised.

Specific reasons for the higher than anticipated external revenue include the following:

- Station Maintenance external revenue due to planned/unplanned maintenance work for Bruce Power and Pickering NGS and sandblasting and machining work for Siemens;

- External revenue for Engineering & Construction due to revenue metering upgrade work being done at the Bruce Heavy Water Plant, Beach TS, Carlton TS, Richview TS, Glendale TS, Lake TS, Nepean TS, Fairchild TS and Leslie TS.
- Asset Management's external revenue is expected to be over budget due to higher than anticipated Customer Impact Assessment requests.
- Real Estate and Facilities' external revenue due to the lump sum payment of easement charges, including the TTC easement payment from the City of Toronto.
-

Building Owners and Managers Association of the Greater Toronto Area ("BOMA") and London Property Management Association ("LPMA") INTERROGATORY #5 List 1

Interrogatory

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

Ref: Exhibit E1, Tab 1, Schedule 2, page 3

a) Please provide the amount included in the $18.4 million of secondary land use revenues shown for 2008 that is associated with the granting of easement rights to Enbridge and the City of Toronto and one-time sales of land.

b) Is Hydro One aware of any one-time events in 2009 or 2010 that may impact on secondary land use revenues? If yes, please provide the details.

Response

a) The amount included in the 2008 forecast associated with the granting of easement rights to Enbridge and the City of Toronto was approximately $7.7 million.

b) Hydro One is not at this point aware of any one time events in years 2009 or 2010 that may impact on secondary land use revenues.

Building Owners and Managers Association of the Greater Toronto Area ("BOMA") and London Property Management Association ("LPMA")
INTERROGATORY #6 List 1

Interrogatory

Issue 3.1 – Are the proposed spending levels for Sustaining and Development OM&A in 2009 and 2010 appropriate, including consideration of factors such as of system reliability and asset condition?

Ref: Exhibit C2, Tab 2, Schedule 1

a) Please provide the most recent year-to-date actual expenditures available for the 2008 bridge year in the same level of detail as shown in this table.

b) Please provide the corresponding year-to-date actual expenditures for the 2007 historic year in the same level of detail as shown in this table.

Response

Pursuant to securities legislation, Hydro One Inc. is a reporting issuer which has certain disclosure obligations. As such, we do not disclose material information pertaining to the corporation which is not already publicly available. The responses to a) and b) below are from information contained in the Hydro One Inc. Q3 Management Discussion and Analysis (MD&A) which is filed at www.sedar.com.

a) The MD&A shows Transmission OM&A of $306 million for the 9 months ending September 30, 2008 (pg.3). Please note that Transmission OM&A as defined in the MD&A also includes a capital tax of $11 million. A breakdown of OM&A expenditures at the same level of detail as Exhibit C2, Tab 2, Schedule 1 is not available in the MD&A.

b) Transmission OM&A is $323 million for the 9 months ending September 30, 2007 (pg.3), including capital tax of $10 million.

As noted in our response in Exhibit I, Tab 1, Schedule 10 Hydro One plans to update evidence for actual 2008 year end results prior to the start of the oral hearing.

Building Owners and Managers Association of the Greater Toronto Area ("BOMA") and London Property Management Association ("LPMA")
INTERROGATORY #7 List 1

Interrogatory

Issue 3.1 – Are the proposed spending levels for Sustaining and Development OM&A in 2009 and 2010 appropriate, including consideration of factors such as of system reliability and asset condition?

Interrogatory # 7
Ref: Exhibit A, Tab 14, Schedule 1, Appendix A

What is the impact on the revenue requirement associated with each of the following:

a) a 1% change in the Ontario CPI;

b) a 1% change in the Tx cost escalation for construction;

c) a 1% change in the Tx cost escalation for operations and maintenance;

d) a change in the exchange rate to 1.20 CDN$/US$.

Response

a) b) c) Hydro One's revenue requirement calculation is not specifically linked to macro economic data, such as CPI. These economic indicators are but one of many factors and considerations, including asset condition, asset age, system reliability and safety, legislated and regulatory requirements among others that go into developing departmental business plans and subsequent costing of programs and projects.

d) The US exchange rate has no material impact on revenue requirement. Hydro One has indicated in interrogatory response Exhibit I, Tab 3, Schedule 7 on how fluctuations in the US exchange rate are managed.

Building Owners and Managers Association of the Greater Toronto Area ("BOMA") and London Property Management Association ("LPMA") INTERROGATORY #8 List 1

Interrogatory

Issue 3.2 – Are the proposed spending levels for Shared Services and Other O&M in 2009 and 2010 appropriate?

Ref: Exhibit C1, Tab 2, Schedule 6, page 30

a) Please provide the total forecast cost associated with the preparation of the current transmission rates application, broken out into its component parts.

b) Is Hydro One proposing to amortize these costs over the 2009 and 2010 test years? If not, please explain.

Response

a) The table below shows the 2009 test year costs associated with the current transmission rates application, EB-2008-0272. There are no costs in 2010 associated with EB-2008-0272.

2009 Costs ($K)	
Incremental Resources	450
Intervenor Funding	400
OEB Costs	50
Special Studies	50
TOTAL	**950**

b) The costs associated with the preparation of the current transmission rates application are expensed in the year in which those costs are incurred, as per Generally Accepted Accounting Principles.

Building Owners and Managers Association of the Greater Toronto Area ("BOMA") and London Property Management Association ("LPMA") INTERROGATORY #9 List 1

Interrogatory

Issue 3.2 – Are the proposed spending levels for Shared Services and Other O&M in 2009 and 2010 appropriate?

Ref: Exhibit C1, Tab 2, Schedule 6, Table 15

a) The other costs in this table have averaged a credit of approximately $12 million over the 2005 through 2008 period. Given that this category is strongly influenced by unexpected items, why has Hydro One forecast 2009 and 2010 at the historical level?

b) Please provide a breakdown of the costs shown for each of 2005 through 2010 in each of the major components that make up this category.

Response

a) Hydro One has not forecast 2009 and 2010 Other OM&A levels at the historical level. As noted in the referenced schedule, Hydro One has forecast Other costs of $2.1M for 2009 and $4.0M for 2010. Since this category is strongly influenced by unexpected items it would not be prudent to include any amounts in this category which cannot be substantiated.

b) The following table shows a breakdown in the 2005 to 2010 Other OM&A costs.

($M)	2005	2006	2007	2008	2009	2010
WSIB		(1.1)	(0.9)	(1.0)	(0.7)	(0.7)
Vacation Reserve		1.5	0.9	1.2	0.9	0.9
Gregorian Adjustment		(0.0)	1.3	(3.7)	(1.4)	1.0
Transmission Hearing Cost		2.7	2.0	2.5	1.8	2.5
Inergi Pension Adjustments	(0.5)			(12.9)		
Proceeds (EG. Transmission Damage Claims)	(11.7)					
Property Accrual Adjustment		(21.6)				
2007/08 – Transmission Decision Adjustments			4.7			
Stretch Target				(7.7)		
Misc	(3.6)	(0.7)	1.2	0.1	1.5	0.2
TOTAL	**(15.8)**	**(19.3)**	**9.2**	**(21.5)**	**2.1**	**4.0**

Building Owners and Managers Association of the Greater Toronto Area ("BOMA") and London Property Management Association ("LPMA") INTERROGATORY #10 List 1

Interrogatory

Issue 3.3 – Are the compensation levels proposed for 2009 and 2010 appropriate?

Ref: Exhibit C1, Tab 3, Schedule 2, page 14

The evidence indicates that *"On an overall weighted average basis for the benchmarked positions, Hydro One is approximately 17% above the market median."*

What would be the impact on the overall revenue requirement if Hydro One compensation was equivalent to the median?

Response

The composition of the overall Hydro One workforce must be taken into consideration when reviewing the impact of attempting to move compensation to the market median. Specifically, as noted in Exhibit C1, Tab 3, Schedule 2, page 2, over 90% of the workforce is unionized and subject to collective bargaining. Any attempt to lower wages would be subject to collective bargaining. Union contracts are currently in place until March 31, 2011 (PWU), March 31st 2013 (The Society) and April 30th 2010 (Building Trades). Non-represented staff were benchmarked to be slightly below market median in the Mercer study.

As stated by Mercer in their Compensation Cost Benchmarking Study, as provided in Exhibit A, Tab 16, Schedule 2, Attachment 1, page 2:

> *Hydro One's productivity for Transmission and Distribution function and Customer Service functions are each measured along four indicators. All indicators measured ranked better than median (i.e., more productive) except one, which is slightly below median (i.e., less productive).* ***Examining the mix of indicators leads to the conclusion that Hydro One requires less workforce compensation to generate various units of output.***

As such, it is not appropriate to focus upon the compensation benchmarking results by themselves without consciously taking into account the workforce productivity results which demonstrate that Hydro One requires less workforce compensation to generation various units of output.

As stated in Exhibit I, Tab 1, Schedule 35, part b):

> *Hydro One has an integrated workforce for its transmission and distribution businesses. This allows Hydro One to take advantage of economies of scale and efficiencies that would not be available through separate transmission and distribution operations. As a result of its integrated workforce, separate workforce data for Hydro One's Transmission Business only is not available.*

This is also the case for compensation costs. That is, as a result of its integrated workforce, separate workforce compensation data for Hydro One's Transmission Business only is not available. Consequently, an estimate of the impact on the overall Hydro One Transmission Revenue Requirement if Hydro One compensation was equivalent to the median can not be provided, even if such an estimate were meaningful without explicitly taking into account workforce productivity.

Building Owners and Managers Association of the Greater Toronto Area ("BOMA") and London Property Management Association ("LPMA") INTERROGATORY #11 List 1

Interrogatory

Issue 3.3 – Are the compensation levels proposed for 2009 and 2010 appropriate?

Ref: Exhibit C1, Tab 3, Schedule 1

Please provide the number of full-time equivalent (FTE) employees that are allocated to transmission for each of 2005, 2006, 2007, 2008 bridge year and 2009 and 2010 test years. If this information is not available, please provide the total wage and salary costs for transmission for each of the years requested. Please also provide the corresponding transmission related benefits costs for each of the years.

Response

As discussed in Exhibit I, Tab 1, Schedule 35, part b) and in Exhibit I, Tab 2, Schedule 10, as a result of its integrated Transmission and Distribution workforce, separate workforce data and compensation data for Hydro One's Transmission Business only is not available. This integrated workforce allows Hydro One to take advantage of economies of scale and efficiencies that would not be available through separate transmission and distribution operations.

<u>Building Owners and Managers Association of the Greater Toronto Area ("BOMA") and London Property Management Association ("LPMA")</u>
<u>INTERROGATORY #12 List 1</u>

Interrogatory

<u>Issue 3.3 – Are the compensation levels proposed for 2009 and 2010 appropriate?</u>

<u>Interrogatory # 12</u>
Ref: Exhibit A, Tab 14, Schedule 1, Appendix A

Please provide the impact on the revenue requirement of each of the following (independent of one another):

a) 2% economic increases effective April 1, 2009 and 2010 for Society Staff;

b) economic increases of 2% effective April 1, 2009 and 2010 for PWU Staff;

c) 2% annual increase per year in base pay for MCP staff.

Response

As discussed in Exhibit I, Tab 2, Schedule 10, as a result of its integrated Transmission and Distribution workforce, separate workforce compensation data for Hydro One's Transmission Business only is not available. This integrated workforce allows Hydro One to take advantage of economies of scale and efficiencies that would not be available through separate transmission and distribution operations. As a result, its not possible to estimate the impact upon proposed 2009 and 2010 Transmission Revenue Requirement of the hypothetical reductions in the economic increases for staff.

Further, as discussed in Exhibit I, Tab 2, Schedule 10, and as noted in Exhibit C1, Tab 3, Schedule 2, page 2, over 90% of the Hydro One workforce is unionized and subject to collective bargaining. Any attempt to change wages would be subject to collective bargaining. PWU and Society Union contracts are currently in place until beyond 2010 which both stipulate annual 3% economic increases in base wages in each of 2009 and 2010. As such, a 2% economic increase in wages would not be possible under union contract terms in the test years.

Building Owners and Managers Association of the Greater Toronto Area ("BOMA") and London Property Management Association ("LPMA") INTERROGATORY #13 List 1

Interrogatory

Issue 3.3 – Are the compensation levels proposed for 2009 and 2010 appropriate?

Interrogatory #13
Ref: Exhibit A, Tab 14, Schedule 1, Appendix A

Please provide the amounts actually paid for each of the last three years, the 2008 bridge year and each of the 2009 and 2010 test years associated with the MCP Short Term Incentive Plan.

Response

Please refer to Exhibit C1, Tab 3, Schedule 2, page 10, table 1. The column labeled "Incentive" provides the annual MCP Short Term Incentive Plan amounts total for Hydro One Networks Inc. staff. As discussed in Exhibit I, Tab 2, Schedule 10, as a result of its integrated Transmission and Distribution workforce, separate workforce compensation data for Hydro One's Transmission Business only is not available. This integrated workforce allows Hydro One to take advantage of economies of scale and efficiencies that would not be available through separate transmission and distribution operations.

Building Owners and Managers Association of the Greater Toronto Area ("BOMA") and London Property Management Association ("LPMA") INTERROGATORY #14 List 1

Interrogatory

Issue 3.5 – Are the amounts proposed to be included in the 2009 and 2010 revenue requirements for income and other taxes appropriate?

Ref: Exhibit C2, Tab 4, Schedule 1

a) Please show the calculation and assumptions used in calculating the $8.7 provincial exemption shown at line 11.

b) Why does this exemption level stay at the same level in 2010 as in 2009?

Response

a) The provincial exemption for Transmission reflected in Exhibit C2, Tab 4, Schedule 1 was calculated in accordance with OEB guidelines of RP-2004-0188, 2006 Electricity Distribution Rate Handbook, Report of the Board dated 2005 May 11, Chapter 7, page 60. The provincial capital exemption is prorated amongst all regulated entities of the Hydro One corporate group:
= $15M x A/B= $8.7M
A = Estimated Transmission Taxable Capital
B = Estimated Aggregate Taxable Capital of Hydro One Inc Regulated entities

For 2010, if 100% of the $15 million exemption was allocated solely to Transmission, the capital tax would be reduced by an incremental $5K {(15M-8.7M) x 0.075%}

b) The exemption stays at the same level in 2010 because the allocation between the regulated Hydro One corporate groups is based on the underlying capital tax base, and hence there is no change in allocation to Transmission for 2010.

<u>Building Owners and Managers Association of the Greater Toronto Area ("BOMA") and London Property Management Association ("LPMA")</u>

<u>INTERROGATORY #15 List 1</u>

Interrogatory

<u>Issue 3.5 – Are the amounts proposed to be included in the 2009 and 2010 revenue requirements for income and other taxes appropriate?</u>

<u>Interrogatory # 15</u>
Ref: Exhibit C2, Tab 2, Schedule 12

a) Please provide the most recent year-to-date actual costs associated with property tax and rights payments for the 2008 bridge year.

b) Please provide the corresponding year-to-date figure for 2007 for the property tax and rights payments categories.

c) Please explain what is driving the forecasted increase in 2008 in property taxes.

d) Please explain what is driving the forecasted increase in 2008 in rights payments.

e) Rights payments for 2009 and 2010 are expected to increase, in part, due to recent increases in land values (page 6 of 7). Given the recent economic downturn, does Hydro One still expect increased costs related to increases in land values?

f) Please provide all calculations and assumptions used in the forecasts for 2009 and 2010 shown in Table 2 for transmission lines and stations and buildings, including proxy tax.

Response

<u>Note: Reference should be C1, Tab 2, Schedule 12</u>

a) Hydro One will be providing actual 2008 property tax and rights costs prior to the start of the oral hearing.

b) In light of the response to part (a), 2007 year end information in Exhibit C2, Tab 2, Schedule 12 provides a more relevant comparison.

c) The forecasted increases in property tax expenditures in 2008 is driven by municipal tax rate increases throughout the Province.

d) The forecasted increase in rights payments expenditures in 2008 and beyond is driven by rent increases tied to increased land values, subject to negotiation by both parties and/or as per other provisions of the agreements.

e) Hydro One expects increased costs related to increases in land values as the majority of the real estate rights agreements due for renewal or currently under negotiations are based on lower historic land values.

f) The assumptions used in calculations of the property tax costs forecasts for 2009 and 2010 are based on:

- An annual 2% municipal tax increase
- No increase in assessed value of Hydro One properties for 2007 & 2008 as re-assessments were cancelled by the Province (Municipal Property Assessment Corporation)
- Increases in property taxes of 2% for 2009, and 2% for 2010 as result of re-assessment.
- No change to proxy tax is assumed

Building Owners and Managers Association of the Greater Toronto Area ("BOMA") and London Property Management Association ("LPMA") INTERROGATORY #16 List 1

Interrogatory

Issue 3.6 – Is Hydro One Networks' proposed depreciation expense for 2009 and 2010 appropriate?

Ref: Exhibit C2, Tab 5, Schedule 1

a) Please provide the most recent year-to-date asset removal costs for 2008.

b) Please provide the corresponding year-to-date figure for 2007.

c) What is driving the significant increase in asset removals costs in 2009 and 2010 as compared to 2008?

Response

As noted in our response in Exhibit I, Tab 1, Schedule 10, Hydro One plans to update evidence for actual 2008 year end results prior to the start of the oral hearing.

a) The most recent publicly available year-to-date results are in the Q3 2008 Management Discussion & Analysis (MD&A) which is filed at www.sedar.com. Assets removal costs for Hydro One Inc. as of September 30, 2008 are $32M. Asset removal costs for Transmission are not specifically identified in the MD&A.

b) Hydro One Inc. asset removal costs as of September 30, 2007 are $32M.

c) Hydro One is forecasting an increase in the planned work program for the transmission business in 2009 and 2010, including sustainment work which involves the removal of old assets which are at end-of-life. The main drivers contributing to the increase in asset removal costs include increased Sustainment work in such programs as
   - Station Facility Re-investments;
   - Power Transformers;
   - Overhead Lines Component Refurbishment and Replacements; and
   - Overhead Lines Refurbishment and Replacements.

Building Owners and Managers Association of the Greater Toronto Area ("BOMA") and London Property Management Association ("LPMA")
INTERROGATORY #17 List 1

Interrogatory

Issue 4.3 – Are the amounts proposed for rate base in 2009 and 2010 appropriate?

Ref: Exhibit D1, Tab 1, Schedule 4, Table 2

Please update Table 2 to include a row for 2008 and include all months where actual inventory levels are known.

Response

As noted in our response in Exhibit I, Tab 1, Schedule 10, Hydro One plans to update evidence for actual 2008 year end results prior to the start of the oral hearing. At that time, Table 2 of Exhibit D1, Tab 1, Schedule 4 will be updated.

Building Owners and Managers Association of the Greater Toronto Area ("BOMA") and London Property Management Association ("LPMA") INTERROGATORY #18 List 1

Interrogatory

Issue 4.3 – Are the amounts proposed for rate base in 2009 and 2010 appropriate?

Ref: Exhibit D1, Tab 3, Schedule 1, Table 1

a) Please provide the most recent year-to-date capital expenditures for the 2008 bridge year and indicate how many months of actual expenditures are included.

b) Please provide the most recent estimate of capital expenditures that reflect actual-year-to-date figures for the 2008 bridge year.

c) What would be the impact on the revenue requirement in 2009 and 2010 if the Board approved capital expenditures that were 10% less than those requested (i.e. a reduction in 2009 capital expenditures of $94.4 million, and a reduction in 2010 capital expenditures of $107.4 million)?

Response

Pursuant to securities legislation, Hydro One Inc. is a reporting issuer which has certain disclosure obligations. As such, we do not disclose material information pertaining to the corporation which is not already publicly available. The responses to a) and b) below are from information contained in the Hydro One Inc. Q3 2008 Management Discussion & Analysis (MD&A) which is filed at www.sedar.com.

a) The MD&A shows Transmission capital of $439M for the 9 months ending September 30, 2008 (pg.6).

b) Please see response to (a) above

c) Hydro One requires all capital funding requested and has responded to the question of project prioritization in Exhibit I, Tab 1, Schedule 10.

For illustrative purposes only, an estimate of the impact of a 10% reduction in capital expenditures is provided as follows:

- Capital Expenditure forecast in 2009 is $944.0 million and 2010 is $1,074.1 million per Exhibit D1, Tab 3, Schedule 1. A 10% reduction amounts to $94.4 million in 2009 and $107.4 million in 2010

- Hydro One has made the assumption that the reduction in capital expenditure results in an equivalent reduction in in-service capital
- Resulting reduction in revenue requirement for 2009 is $5.0M and for 2010 is $15.0M.

As with all forecasts, there will be components of the test year forecasts that will be higher or lower than forecast. It is inappropriate to look at the impact on revenue requirement of a change in only one component of the test year forecast without consideration of changes in other forecast elements.

As noted in our response in Exhibit I, Tab 1, Schedule 10, Hydro One plans to update evidence for actual 2008 year end results prior to the start of the oral hearing.

Building Owners and Managers Association of the Greater Toronto Area ("BOMA") and London Property Management Association ("LPMA") INTERROGATORY #19 List 1

Interrogatory

Issue 4.4 – Is the forecast of long term debt for 2008-2010 appropriate?

Ref: Exhibit B1, Tab 1, Schedule 1, page 4

a) What is the impact of a ten basis point change in the deemed long term debt rate for affiliate debt rate on the overall revenue requirement in 2009? In 2010?

b) Please provide an update to the deemed long term debt rate for affiliate debt based on the most recently available *Consensus Forecast*.

Response

a) If the deemed long-term debt rate were changed by ten basis points, revenue requirement in 2009 would change by $0.2 million. There would be no impact on 2010 revenue requirement for a 10 basis point change in deemed long-term debt as the amount of deemed long-term debt in 2010 is negligible.

b)

	2009	2010
Deemed Long-Term Debt Rate	7.83%	8.48%

Based on 30 year Government of Canada bond yield forecast, as shown in part (b) of Exhibit I, Tab 2, Schedule 1, adjusted by November 2008 average spreads, as discussed in lines 12 to 15 of page 5 of Exhibit A, Tab14, Schedule 2.

Building Owners and Managers Association of the Greater Toronto Area ("BOMA") and London Property Management Association ("LPMA") INTERROGATORY #20 List 1

Interrogatory

Issue 4.4 – Is the forecast of long term debt for 2008-2010 appropriate?

Ref: Exhibit B1, Tab 2, Schedule 1, Tables 2, 3 & 4

a) Has the forecasted debt issue shown in Table 2 for 2008 taken place? If yes, please provide the actual principal amount, term and rate. If not, please provide an update to the forecast based on current market conditions.

b) Please provide an update to the forecast shown in Table 3 for 2009 and 2010 based on current market conditions.

c) Please explain why Hydro One has assumed an equal amount of debt for each of the 5, 10 and 30 year terms. What would be the impact on the 2009 and 2010 revenue requirements if the forecast debt issues for 2009 and 2010 were split 50% to a 5 year term and 50% to a 10 year term?

d) Please provide an update to the forecasts shown in Table 4 using the most recent *Consensus Forecasts* available and the November, 2008 average spreads for five-year to ten year and thirty-year to ten-year bond yields. Please also update the calculation based on the average of indicative new issue spreads for the most recent month available obtained from the Company's MTN dealer group for each planned issuance term.

Response

a) Forecast debt issuance for 2008 has taken place. The following table provides the actual principal amount, term and rate of debt issues that have taken place.

2008		
Principal Amount ($ Millions)	**Term (Years)**	**Coupon**
240.0	5	5.00%
60.0	2	3.89%

b) The forecast principal amounts and terms have not changed. An update to the forecast coupon rates is provided in part (d).

c) Please refer to response to interrogatory I-1-6 for an explanation of why Hydro One has assumed an equal amount of debt each of the 5, 10 and 30 year terms.

If forecasted debt issues for 2009 and 2010 were split 50% to a 5 year term and 50% to a 10 year term, 2009 revenue requirement would be lower by $2.7M and 2010 revenue requirement would be lower by $4.9M

d) The most recent *Consensus Forecasts* does not have a 2008 forecast. The rate on actual issuance in 2008 is provided in part (a). The following is an update to the forecasts for 2009 and 2010 shown in Table 4 using the most recent *Consensus Forecasts* available and the November 2008 average spreads.

	2009		
	5-year	**10-year**	**30-year**
Government of Canada	2.92%	3.85%	4.40%
Hydro One Spread	2.16%	2.38%	2.57%
Forecast Hydro One Yield	5.08%	6.23%	6.97%
	2010		
	5-year	**10-year**	**30-year**
Government of Canada	3.57%	4.50%	5.05%
Hydro One Spread	2.16%	2.38%	2.57%
Forecast Hydro One Yield	5.73%	6.88%	7.62%

Building Owners and Managers Association of the Greater Toronto Area ("BOMA") and London Property Management Association ("LPMA")
INTERROGATORY #21 List 1

Interrogatory

Issue 4.4 – Is the forecast of long term debt for 2008-2010 appropriate?

Ref: Exhibit B2, Tab 1, Schedule 2, page 4

Please provide the most recent forecast of Treasury O&M costs and Other financing-related fees for 2008.

Response

As noted in our response in Exhibit I, Tab 1, Schedule 10, Hydro One plans to update evidence for actual 2008 year end results prior to the start of the oral hearing. At that time the Treasury O&M costs and Other financing related costs shown in Exhibit B2, Tab 1, Schedule 2, page 4 will be updated.

Building Owners and Managers Association of the Greater Toronto Area ("BOMA") and London Property Management Association ("LPMA") INTERROGATORY #22 List 1

Interrogatory

Issue 5.1 Are the proposed amounts and disposition for each of the deferral and variance accounts appropriate?

Ref: Exhibit F1, Tab 1, Schedule 1, page 4

Please provide the 2007 budget year OEB cost assessment and the actual 2007 and 2008 OEB cost assessment, as well as the forecast for 2009. Has the 2008 OEB cost assessment been finalized, or does the cost include some forecast?

Response

($ millions)	**Budget 2007**	**Actual 2007**	**Actual 2008**	**Test 2009**
OEB Transmission Cost assessment	6.0	5.1	3.7	3.6

The OEB cost assessment for the OEB fiscal year 2008-2009, ending March 31, 2009, has been finalized.

<u>Building Owners and Managers Association of the Greater Toronto Area ("BOMA") and London Property Management Association ("LPMA")</u>

<u>INTERROGATORY #23 List 1</u>

Interrogatory

Issue 5.1 Are the proposed amounts and disposition for each of the deferral and variance accounts appropriate?

Ref: Exhibit F1, Tab 2, Schedule 1, page 2

Please clarify whether or not the reduction in the revenue requirement in 2009 and 2010 as a result of the disposition of the regulatory assets balance is reflected in the calculations of the revenue deficiency shown in Exhibit E1, Tab 1, Schedule 1. If the reductions are shown there, please explain precisely where in Table 4 these reductions are shown. If these reductions are included in the "Other Cost Charges" please explain the differences between the regulatory asset figures for 2009 and 2010 and the figures provided in Table 4.

Response

The disposition of regulatory assets balance are reflected in "Other Cost Charges" in Exhibit E1, Tab1, Schedule 1, Table 4.

Please refer to Exhibit I, Tab 1, Schedule 15, for the detailed breakdown of Other Cost Charges which includes the regulatory assets shown in Exhibit F1, Tab 2, Schedule 1.

Building Owners and Managers Association of the Greater Toronto Area ("BOMA") and London Property Management Association ("LPMA") INTERROGATORY #24 List 1

Interrogatory

Issue 5.1 Are the proposed amounts and disposition for each of the deferral and variance accounts appropriate?

Ref: Exhibit F2, Tab 1, Schedule 2

a) Please confirm the following annual disposition of regulatory assets (in $ Millions) if the time horizon is reduced from the four years proposed by Hydro One as follows:

Period	2009	2010	2011	2012	2013	Total
Three year	(3.05)	(6.1)	(6.1)	(3.05)	0.0	(18.3)
Two Year	(4.575)	(9.15)	(4.575)	0.0	0.0	(18.3)
18 Months	(6.1)	(18.2)	0.0	0.0	0.0	(18.3)

b) If the figures provided in (a) above cannot be confirmed, please provide the annual disposition figures under each of the three time horizons provided.

c) Given the significant increase in the revenue requirement of $62 million in 2009 (Exhibit E1, Tab 1, Schedule 1, Table 3) and $110 million in 2010 (Exhibit E1, Tab 1, Schedule 1, Table 5), please explain why the regulatory asset credit should not be used to reduce the revenue requirements to the maximum extent possible to mitigate the overall increase.

Response

a) and b) The three year and two year figures can be confirmed but the 18 month disposition should be as follows:

Period	2009	2010	2011	2012	2013	Total
18 Months	(6.1)	(12.2)	0.0	0.0	0.0	(18.3)

c) Hydro One Transmission is proposing a four year recovery period to maintain consistency with recovery periods approved for other Regulatory Accounts within the Company's Electricity Transmission and Distribution businesses, such as the 2007-2008 Transmission Rate Proceeding (EB-2006-0501), the 2006 Distribution Rate Proceeding (RP-2005-0020/ EB-2005-0378) and the 2004 Regulatory Assets Review Proceeding (RP-2004-0117/0118). A four year recovery helps to smooth the customer impact and interest is applied to the principle balance to appropriately reflect the time value of money for the customer and the company.

Building Owners and Managers Association of the Greater Toronto Area ("BOMA") and London Property Management Association ("LPMA") INTERROGATORY #25 List 1

Interrogatory

Issue 5.1 Are the proposed amounts and disposition for each of the deferral and variance accounts appropriate?

Ref: Exhibit F2, Tab 1, Schedule 3

Please show the calculation and all assumptions used in the calculation of the Transactions During Year column for the tax rate changes of ($3.5) in 2007, ($6.2) in 2008 and ($3.7) in 2009.

Response

	2007	2008	2009	
Changes Capital tax rates				
Capital tax per OEB decision *	15.7	16.4	16.4	(a)
Rate - per filing	0.285%	0.285%	0.285%	(b)
Rate - effective rate	0.225%	0.225%	0.225%	(c)
Revised capital tax	12.4	12.9	12.9	(d) = (a) x (c) / (b)
Change	(3.3)	(3.5)	(3.5)	(e) = (d) - (a)
Changes in Income tax rates				
Income tax per OEB decision *	64.7	52.7	52.7	(f)
Rate - per filing	36.12%	34.50%	34.50%	(g)
Rate - effective rate	36.12%	33.50%	33.00%	(h)
Revised income tax (before gross up)	64.7	51.2	50.4	(i) = (f) x (h) / (g)
Change (before gross up)	0.0	(1.5)	(2.3)	(j) = (i) - (f)
Change (after gross up)	0.0	(2.3)	(3.4)	(k) = (j) / (1 - (h))
CCA rate change of class 45 (from 45% to 55%)				
Higher CCA deduction due to change	0.324	0.799	0.799	(l)
Income tax rate per filing	36.12%	34.50%	34.50%	(m)
Tax impact (before gross up)	(0.117)	(0.276)	(0.276)	(n) = -(l) x (m)
Tax impact (after gross up)	(0.183)	(0.421)	(0.421)	(o) = (n) / (1 - (m))
Sub-Total	(3.5)	(6.2)	(7.3)	(p) = (e) + (k) + (o)
Effective Months	12	12	6	(q)
Total Tax Deferral	(3.5)	(6.2)	(3.7)	(r) = (p) x (q) / 12

* Per Hydro One Networks 2007 and 2008 Electricity Transmission Revenue Requirements - Final Revenue Requirements & Charge Determinants (Exhibit 1.1).

Lewis Balogh INTERROGATORY #1 List 1

Interrogatory

1. What cost-cutting measures did Hydro One take in the past three years that could have made this increase of its electricity transmission unnecessary?

Response

An overview of Hydro One Transmissions's efforts to improve cost efficiency and to review productivity and compensation cost against comparable companies are presented in Exhibit A, Tab 16, Schedule 1 (Cost Efficiencies and Productivity) and Exhibit A, Tab 16, Schedule 2 (Compensation Cost and Benchmarking Productivity Study) respectively. Please see those Exhibits for a full discussion of productivity and cost efficiency.

Cost savings are identified annually during the business planning process, and those achieved between 2005 and 2007, and forecasted for 2008 to 2010, are shown in Exhibit A, Tab 16, Schedule 1, Table 1 (this table is copied in Exhibit I, Tab 3, Schedule 2). These are year over year "incremental savings", which are savings over and above those already embedded in the costs of individual programs.

Improving cost efficiency continues to be a core element of the Hydro One Transmission strategy. Hydro One Transmission will continue to make prudent and responsible economic efficiency improvements consistent with our business strategy in order to deliver steady financial performance, sustain company assets and deliver safe, economic and reliable electrical energy.

As outlined in Exhibit A, Tab 16, Schedule 1,page 2:

> *Hydro One Transmission's future challenges are similar to those presented in our last Transmission filing: major growth in work programs, the replacement of end-of-life IT infrastructure and aging staff demographics coupled with a highly competitive labour market due to worldwide scarcity of core skills in the electricity industry. Nevertheless, Hydro One Transmission is pursuing opportunities to transform business processes, which will ensure Hydro One Transmission maintains its vision of being an efficient and dynamic electricity transmission and distribution company.*

Significant cost efficiencies have been highlighted in the evidence for previous rate filings. Some specific examples of cost-efficiency initiatives are presented on Exhibit A, Tab 16, Schedule 1, pages 2 and 3.

Exhibit A, Tab 16, Schedule 2 summarizes a study that was completed reviewing Hydro One's compensation costs and productivity relative to the market. As summarized in Exhibit A, Tab 16, Schedule 1, pages 12 and 13:

The study results show that Hydro One Transmission's productivity is better than or approximately at median performance for all of the Total Transmission and Distribution productivity indicators. As stated by Mercer/ Oliver Wyman in their study report, "examining the mix of [productivity] indicators leads to the conclusion that Hydro One requires less workforce compensation to generate various units of output".

Lewis Balogh INTERROGATORY #2 List 1

Interrogatory

2. What were the results of these measures?

Response

Please refer to Exhibit I, Tab 3, Schedule 1 as well as Exhibit A, Tab 16, Schedule 1 (Cost Efficiencies and Productivity) for a more detailed response to this question.

For convenience, Exhibit A, Tab 16, Schedule 1, Table 1 is reproduced below. The table shows cost savings identified annually during the business planning process, and includes those achieved between 2005 and 2007, and forecasted for 2008 to 2010.

Table 1
Total Incremental Cost Savings - Transmission

	2005 Actual	2006 Actual	2007 Actual	2008 Bridge	2009 Test	2010 Test	Total
OM&A (non-Cornerstone) Savings ($M)	7.0	2.7	3.1	2.4	1.9	1.4	28.5
Capital (non-Cornerstone) Savings ($M)	1.4	2.8	0.6	3.0	3.0	3.8	21.6
Cornerstone OM&A Savings ($M)	0	0	0	0	6.0	4.0	10.0
Cornerstone Capital Savings ($M)	0	0	0	0	5.0	2.0	7.0
Total Savings ($M)	8.4	5.4	3.7	5.4	15.9	11.2	50.1
Total Spend** ($M)	691	776	973	1,096	1,379	1,524	6,439
Savings as % of Total Spend	1.2%	0.7%	0.4%	0.5%	1.2%	0.7%	0.8%

**Total Spend includes Transmission capital plus OM&A expenditures

Further, as stated on Exhibit A, Tab 16, Schedule 1, page 5:

> *[These] cost savings are identified as year over year "incremental savings" defined as savings over and above those already embedded in the costs of individual programs. Accordingly, the first year impact of a new initiative or enhancements to an initiative are identified and the target associated with that initiative is subsequently monitored to establish the actual savings achieved. Under this concept of incremental savings, the savings beyond the first year are considered to be "embedded" savings for purposes of the annual business plans and are therefore not included in the annual estimates of incremental savings unless enhancements to those initiatives are made. As a result, the incremental savings estimates substantially understate the savings from those initiatives that have a cost efficiency impact over more than one year.*

Lewis Balogh INTERROGATORY #3 List 1

Interrogatory

3. Did Hydro-One consider the benefit-cost ratio of privatizing some of the maintenance of its power lines or rights-of-way for the purpose of cost reduction? If this was done, what was the ratio?

Response

Hydro One does not use a cost-benefit ratio in determining whether to contract out the maintenance of its power line rights-of–way. Please see the response to Interrogatory Exhibit I, Tab 3, Schedule 8 for a response on Hydro One's cost effective approach to the maintenance of its rights-of-way.

Lewis Balogh INTERROGATORY #4 List 1

Interrogatory

4. In light of the current economic slowdown would it not be prudent to re-examine the forecast for the consumption of electrical energy and its effects on the transmission network?

Response

Please refer to Hydro One's response provided at Exhibit I, Tab 1, Schedule 10.

Lewis Balogh INTERROGATORY #1 List 2

Interrogatory

Issue 2.2: Are the revenue forecasts appropriate?

1. The outlook for the next 24-30 months presents a possible negative growth of the economy, possibly even a recession. In view of this, is it realistic to plan for an ROE of8.53% and 9.35% for 2008, 2009 respectively?

Response

The methodology for determining the ROE for electricity transmission utilities is established following the Ontario Energy Board's cost of capital guidelines. The methodology includes an adjustment mechanism to factor in changes in interest rates. As noted in response to Exhibit I, Tab 1, Schedule 3, Hydro One expects that the return on equity will be updated by the OEB in accordance with the adjustment methodology in the Cost of Capital Report. This adjustment will capture any recessionary impacts on the cost of capital over the next two years.

Lewis Balogh INTERROGATORY #2 List 2

Interrogatory

Issue 2.2: Are the revenue forecasts appropriate?

2. Hydro One seeks a yearly revenue increase of8% from 2009, while the four-year seasonally adjusted CPI is about 1.81%.
   How is this justified?

Response

The CPI is one economic indicator used as a guideline in developing the department's business plans and subsequent costing of programs and projects. Hydro One's revenue requirement is not directly linked to this parameter.

The major driver in the increase in rates relates to asset replacement and refurbishment needs of our aging system and system expansion as described in Exhibit D1, Tab 3, Schedule 1. Exhibit E1, Tab 1, Schedule 1, Table 4 compares 2009 and 2010 revenue requirement and confirms the major component of the increase relates to depreciation ($24 million) and return on capital ($65 million), both related to the increase in in-service assets.

Lewis Balogh INTERROGATORY #3 List 1

Interrogatory

Issue 2.2: Are the revenue forecasts appropriate?

3. If and when Hydro One carries on business with entities in the United States, how does Hydro One manage the wide fluctuations of the rate of exchange between the two currencies?

Response

Hydro One manages the rate of exchange between the two currencies in two ways:

1) Hydro One attempts to secure U.S. Dollar contracts in the Canadian Dollar equivalent at the time the contract is negotiated, thereby transferring all currency fluctuation risk to the vendor.

2) When Hydro One is unable to negotiate Canadian Dollar payments, Hydro One's strategy is to hedge material U.S. Dollar cash requirements that are highly certain.

Lewis Balogh INTERROGATORY #4 List 2

Interrogatory

Issue 3.1: Are the proposed spending levels for Sustaining Development and Operations OM&A in 1009 and 2010 appropriate, including consideration of factors such as system reliability and asset condition?{sic}

4. The cost estimate for vegetable management is $47.9 million. As this work is seasonal, would it not be more cost-effective to contract it out to companies that specialize in that type of business? It could also lessen the need for replacing some of the retiring employees.

Response

Hydro One uses an optimum mix of permanent employees and hiring hall staff rather than contractors for forestry work. Hiring hall staff are not full time employees. These employees complement the permanent work force and are employed during peak periods to complete the necessary work.

Hydro One maintains a core of experienced foresters as permanent staff and plans to replace retiring employees are centred on these staff. Employing temporary hiring hall staff or contractors does not change the requirement to replace full time staff that will be retiring.

Lewis Balogh INTERROGATORY #5 List 2

Interrogatory

Issue 3.1: Are the proposed spending levels for Sustaining Development and Operations OM&A in 1009 and 2010 appropriate, including consideration of factors such as system reliability and asset condition?{sic}

5. The OM&A is estimated to increase in 2009 by 8% and in 2010 by a further 3% due to the aging of equipment. Does Hydro One maintain a capital reserve in its budget to replace them?
   Would the depreciation of the equipment approaching their useful life, if allowed, reduce the capital expenditure of their replacement?

Response

Hydro One does not maintain a capital reserve to replace end of life equipment.

Depreciation of equipment does not reduce the capital expenditure of the replacement. Depreciation is an accounting methodology to write-off the cost of an asset over its useful life and therefore does not have an effect on the cost of the new replacement asset.

<u>School Energy Coalition (SEC) INTERROGATORY #1 List 1</u>

Interrogatory

1. Ref. Ex. A-12-1, Att. 7, S&P Ratings Report: At p. 7 of the S&P report there is a reference to HON's preparation for the Canadian Accounting Standards Board's convergence to International Financial Reporting Standards (IFRS).

   (a) Please set out all steps HON has taken in respect of this change in accounting standard, in particular as they relate to the rate filing.

   (b) Please specify any changes that HON has made or is planning to make to its capitalization policy as a result of the planned convergence to IFRS standards.

Response

(a) Hydro One provides status updates and a summary of steps taken to date in the IFRS conversion project in its quarterly Management's Discussion and Analysis included in its quarterly external financial report. The most recent report has been filed at Exhibit A, Tab 11, Schedule 2, Attachment 2, page 9.

(b) Hydro One will review its capitalization policy as part of its IFRS conversion project and will comply with IFRS requirements. At this stage of the project, it is anticipated that fewer costs will qualify for capitalization than currently.

School Energy Coalition (SEC) INTERROGATORY #2 List 1

Interrogatory

I. Administration

Ref. Ex. A/14/1: Business Planning

a) Please provide, on a confidential basis if necessary, a copy of the business plan provided to HON Board of Directors for approval

Response

a) The requested information will be filed in confidence following the OEB confidentiality guidelines.

School Energy Coalition (SEC) INTERROGATORY #3 List 1

Interrogatory

A-14-1, Appendix A- Business Plan Assumptions

(a) Have any of the assumptions in Appendix A changed since the application was prepared?

(b) In particular, have the assumptions for inflation rate (which are based on December 2007 data) and interest rates (which are based on April 2008 data) changed as a result of the recent economic conditions.

(c) If the answer to (a) or (b) is yes, please provide the updated assumptions and provide the corresponding amendments to the OM&A or capital budgets.

(d) With respect to labour escalation, HON has assumed 2.5% increase for Society staff, a 3% increase for PWU staff, and a 4% increase for MCP. What is the basis for the MCP assumption and why is it greater than either the PWU or Society escalation?

Response

(a), (b), (c) Some of the forecasts that support the assumptions in Appendix A have changed, however Hydro One has not changed the 2009 Business Plan Assumptions. Please see response Exhibit I, Tab 1, Schedule 10 regarding how Hydro One plans to address changes in economic conditions.

(d) Please refer to Exhibit I, Tab 10, Schedule 1.

School Energy Coalition (SEC) INTERROGATORY #4 List 1

Interrogatory

I. Administration

Ex. A/14/2: Economic Indicators

Pg. 4: there is a substantial increase in HON's credit spreads for the 5-year, 10-year and 30-year bond rates. The evidence, at p.5, states that the credit spreads "are based on the average of indicative new issue spreads for March 2008 obtained from our Medium Term Note program dealer group for each planned issuance term."

(a) Please provide HON's understanding for the increase in the actual credit spreads in 2008.

(b) Please explain the basis for assuming that the increase in credit spreads will continue in 2009 and 2010.

Response

(a) The increase in HON’s credit spreads is due to the general increase in credit spreads in the Canadian debt markets as a result of the ongoing crisis in the credit markets.

(b) Similar to methodology outlined in Appendix A (i.e. Method to Update of the Deemed Long-term Debt Rate) and Appendix B (i.e. Method to Update the ROE) of the Cost of Capital report, Hydro One uses the average of the actual term bond yield spreads and credit spreads for the month as the basis for forecast debt rates.

School Energy Coalition (SEC) INTERROGATORY #5 List 1

Interrogatory

Cost of Capital

Ref. Exhibit B1/2/1, and B2/1/2- Cost Rate for Debt

(a) Please explain how the Effective Cost Rate for each of the three debt issuances in 2009 and 2010 was determined.

(b) With respect to the debt issued September 15, 2008, is the effective cost rate (5.5%) forecast or actual? If forecast, please provide the actual.

Response

(a) The derivation of the cost rate or yield for each of the three debt issuances forecast for 2009 and 2010 is provided in Exhibit I, Tab 1, Schedule 7, part (a).

(b) The cost rate of 5.5% is forecast. The rate on actual issuance in 2008 is provided in Exhibit I, Tab 2, Schedule 20, part (a).

School Energy Coalition (SEC) INTERROGATORY #6 List 1

Interrogatory

Cost of Capital

Ref. A/14/4, p.2-8

(a) Is there a document or documents that summarize(s) the planned Sustainment OM&A and capital program and provides justifications along the lines set out in this exhibit (i.e. summarising asset condition, reliability, utilization and formulating a plan)? If so, please provide a copy.

Response

(a) No, there is no document that summarizes the planned Sustainment programs along the noted lines. However, Exhibit C1, Tab 2, Schedule 2 (Sustaining OM&A) and Exhibit D1, Tab 3, Schedules 2 and 3 (Sustaining and Development Capital) have been written to align with the process in the referenced exhibit. In particular, the discussion of each OM&A and Capital program includes a sub-section titled "Investment Plan Process" which describes the data and process used to determine the required program spend.

School Energy Coalition (SEC) INTERROGATORY #7 List 1

Interrogatory

Load Forecast

Ex. A/14/3

(a) According to Exhibit E1/1/1, pg. 6, $36 million of the 2010 revenue deficiency is attributed to changes in load forecast for 2010. We have seen, however, that economic conditions underlying the forecast can change significantly in a short period of time. Therefore, does HON propose to update its load forecast prior to the 2010 test year to reduce the risk of forecasting error?

(b) Pg. 15- difference between IESO and HON treatment of CDM. It appears from Attachment B that one of the two main difference between the treatment of CDM as between IESO and HON is that IESO deducts demand response programs from the OPA CDM forecast, whereas HON does not.

(i) What is IESO's rationale for deducting the impact of demand response programs from the CDM forecast?

(ii) What is HON's rationale for not deducting demand response from CDM?

(iii) Demand response programs typically only operate during periods of extreme weather. Would HON's weather normalization methodology not already account for the impact of extreme weather such that including the impact of demand response programs is double counting?

(c) Another main difference between IESO and HON forecasts is the treatment of embedded generation:

(i) If possible, please separately identify the impact of the difference in CDM definitions and the impact of the difference in the definition/treatment of embedded generation (the evidence currently provides the impact for both combined- 400MW for summer 2009);

(ii) Please provide a more detailed explanation of the difference in the treatment of embedded generation as between IESO and HON, including an explanation as to how each party (IESO and HON) justifies its definition.

Response

Note: The following responses were reviewed by the IESO)

a) Please refer to Hydro One's response provided at Exhibit I, Tab 1, Schedule 10.

b)

(i) Since market opening the IESO has treated demand response programs as a resource capacity with no impact on load. Dispatchable Loads, the Transitional Demand Response Program and the Hour Ahead Dispatchable Loads are treated as resources. It is consistent to use the same approach for the OPA's Demand Response programs. The IESO adjusts the OPA's CDM numbers by removing the associated demand response savings from the total savings. The IESO then decrements its demand forecast by these adjusted OPA CDM numbers and accounts for the OPA's demand response programs on the resource side of the ledger. This response was provided by the IESO.

(ii) Hydro One uses the same approach as OPA in treating demand response programs as part of CDM programs which will result in a reduction of peak demand.

(iii)Hydro One uses the same approach as OPA in reducing CDM impacts, including demand response programs, from a weather normal load forecast. It should be noted that weather normal load forecast also has peak conditions that will trigger demand response programs. There is no double counting.

c)

(i) Hydro One does not have the CDM and embedded generation forecast details from IESO and therefore cannot separately identify the impact of CDM and embedded generation from IESO's load forecast. Hydro One's load forecast does show the impact of the two items separately in Table 3 of Exhibit A, Tab 14, Schedule 3.

(ii) Hydro One's embedded generation forecast pertains to renewable generation projects that are greater than 500 kW and cogeneration projects that are greater than 10 MW. These projects are incremental to OPA's customer based generation projects that are included its CDM forecast, which only capture renewable generation projects less than 500 kW and cogeneration projects less than 10 MW. Since these embedded generation projects result in a reduction in peak demand, they are treated as a reduction from the load forecast. Hydro One does not have the embedded generation forecast from IESO, but understands that IESO also treat these embedded generation projects as a reduction in demand.

School Energy Coalition (SEC) INTERROGATORY #8 List 1

Interrogatory

C1/2/2- Sustaining OM&A

The evidence states, at p. 2, that the increasing sustaining OM&A expenditures for assets reaching mid to end of life "will be alleviated in the longer term through capital investments to replace these aging assets." What proportion of the assets currently being repaired or refurbished have to be replaced within the next five years?

Response

None. Equipment planned for replacement within the next five years are not targeted for refurbishment or replacement.

School Energy Coalition (SEC) INTERROGATORY #9 List 1

Interrogatory

C1/2/2- Sustaining OM&A

0C1/2/2: Sustaining OM&A: Stations

(a) Pg. 10, line 21: Please provide the current demographic profile of HON's transformer assets.

(b) Pg. 10, line 23: the evidence states that transformer oil leaks are increasing in volume because many of the leaking units have temporary repairs or temporary oil leak containment. Please explain when the temporary repairs or containment were done and why they were done in that fashion.

(c) Pg. 11-12- Stations: Environmental Management budget: the budget for Environmental Management is increases by $5.6 million, or 160%, between 2005 and 2009.

(i) Please provide a breakdown of the drivers of the increase between 2005 and 2007 (from $3.5 million to $8.4 million), separated by new work accomplishment (and the associated cost) and inflationary increases.

(ii) Please provide a breakdown of the drivers of the increase between 2007 and 2009, separated by new work accomplishment (and the projected associated cost) and projected inflationary increases.

Response

(a) Please see the Exhibit D1, Tab 3, Schedule 2, Page 20. Figure 5 shows the demographics of all power transformer assets.

(b) Transformer oil leak repairs are done in a temporary fashion when they are discovered through our corrective maintenance programs. Temporary repairs are made to immediately respond to the environmental concerns associated with the oil leak and are a stop gap measure until more permanent repairs can be scheduled. Permanent repairs require outages and specific resources. The transformers that merit permanent repairs have been identified and prioritized based on environmental and equipment considerations.

(c)

(i) The increase in expenditures for Environmental Management over the 2005–2007 period is $4.9 million (about 140%). The inflationary increases that Hydro One has experienced from 2005 to 2010 are described in Exhibit A, Tab 14, Schedule 2, pages 1 through 8. Over the 2005 – 2007 period the composite wage and material escalation was about 7.6%.

The Environmental Management expenditures without composite wage and material escalation increase about $4.3 million over the 2005 to 2007 period. The program activities which account for this increase are:

- Emergency Response Plans: $0.4 million
- PCB & Regulated Waste Management: $1.9 million
- Power Transformer Oil Leak Reduction: $0.6 million
- Spill Containment Systems: $0.7 million
- Other (corrective, inspections, site clean-ups etc): $0.7 million

(ii) The increase in expenditures for Environmental Management over the 2007–2009 period is $0.7 million (about 8%). The inflationary increases that Hydro One has experienced from 2007 to 2009 are described in Exhibit A, Tab 14, Schedule 2, pages 1 through 8. Over the 2007 – 2009 period the composite wage and material escalation was about 4.5%.

The Environmental Management expenditure increase without composite wage and material escalation is about $0.3 million over the 2007 to 2009 period due to increased expenditures for the transformer oil leakage reduction program.

School Energy Coalition (SEC) INTERROGATORY #10 List 1

Interrogatory

C1/2/2- Sustaining OM&A

Exhibit C1/2/2, pg. 12: Sustaining OM&A: Stations; Power Equipment- by 2010, the Power Equipment budget will be nearly double what it was in 2005 ($82 million vs. $42.2 million in 2005, a 94% increase).

(a) Provide the proportion of the increase from 2005 that is due to inflationary factors (wage escalation, materials, etc.);

(b) For the proportion of the increase that is due to new work programs, please specify what new work was accomplished;

(c) Please provide greater detail as to what new work will be accomplished to account for the $14.2 million (2009) and $22 million increase (2010) in expenditures over 2008 in each of the test years.

Response

a) The increase in expenditures for Power Equipment over the 2005 – 2010 was $39.8 million (about 94%). The inflationary increases from 2005 to 2010 are described in Exhibit A, Tab 14, Schedule 2. Over the 2005 – 2010 period the composite wage and material escalation for transmission O&M is estimated to be about 13%.

b) The Stations OM&A expenditures increased about 71%, without composite wage and material escalation, over the 2005 to 2010 period. The program activities which account for this increase are:

- Preventative Maintenance: 25%.
- Corrective Maintenance: 18%.
- Transformer Refurbishments: 43%.
- Breaker Refurbishments: 10%.
- Other Maintenance: 4%.

c) The 2009 and 2010 expenditures for Power Equipment over 2008 are $14.7 million and $22 million respectively. Composite wage and material escalation since 2008 is conservatively estimated to be 1.4% for 2009 and 2.1% for 2010as shown in Exhibit

A, Tab 14, Schedule 2. As indicated in b) the bulk of the increases are attributed to additional work in established programs. The program activities which account for this increase, without composite wage and material escalation, for 2009 over 2008 and 2010 over 2008 are provided in the table below.

Existing Program	2009 increase over 2008 (%)	2010 increase over 2008 (%)
Preventative Maintenance	30	34
Corrective Maintenance	-3	0
Transformer Refurbishments	57	49
Breaker Refurbishments	11	12
Other	5	5

School Energy Coalition (SEC) INTERROGATORY #11 List 1

Interrogatory

C1/2/2- Sustaining OM&A

Exhibit C1/2/2, p. 25: Sustaining OM&A: Stations: Ancillary Systems Maintenance: the budget for this program nearly doubles from 2005 to 2010- from $9.9 million to $18.2 million. Please:

(a) Provide the proportion of the increase from 2005 that is due to inflationary factors (wage escalation, materials, etc.);

(b) For the proportion of the increase in the test years that is due to new work programs, please specify what new work will be accomplished;

(c) Please provide the number of trouble calls from 2005 to 2007 as well as the forecast numbers in 2009 and 2010.

(d) To the extent that a projected increase in trouble calls accounts for increased budget forecast in the test years, please quantify the impact.

Response

(a) The increase in expenditures for Ancillary Systems over the 2005 – 2010 is $11.1 million (about 112%). The inflationary increases that Hydro One has experienced from 2005 to 2010 are described in Exhibit A, Tab 14, Schedule 2, pages 1 through 8. Over the 2005 – 2010 period the wage and material escalation is about 13%.

(b) The 2009 and 2010 expenditures for Ancillary Systems over 2008 are $4.3 million and $7.1 million respectively. Wage and material escalation over 2008 was 1.4% for 2009 and 2.1% for 2010. The bulk of the increases are attributed to more work on established programs. The program activities which account for this increase for 2009 over 2008 and 2010 over 2008 are provided in the table below.

Existing Program	% Contribution to 2009 increase over 2008	% Contribution to 2010 increase over 2008
Preventative Maintenance	40%	47%
Corrective Maintenance	6%	19%
Grounding Refurbishments	5%	4%
Ancillary Services Refurbishment	49%	31%

(c) The total number of actual Station trouble calls received from 2005 to 2007 are 8614, 8288 and 8280 respectively. The number of Trouble calls expected in 2009 and 2010 are 8400 for each year.

(d) The change in trouble calls does not contribute to an increased budget forecast in the test years.

School Energy Coalition (SEC) INTERROGATORY #12 List 1

Interrogatory

C1/2/2- Sustaining OM&A

C1/2/2, p. 33: Sustaining OM&A: Vegetation Management

The evidence states, at p. 35, that the proposed spending for brush control and line clearing will allow annual clearing of about 2,800 kilometres of rights of way.

(a) Please provide the annual accomplishment for the years 2005-2008.

(b) Please explain any significant year over year variation in per unit costs.

Response

a) The 2,800 km of accomplishment referenced is specific to line clearing and yearly accomplishments are as follows:

2005 – 3,207 km	unit cost = $1,497
2006 – 2,920 km	unit cost = $1,164
2007 – 2,722 km	unit cost = $1,543
2008 – 2,522 km (projected)	unit cost = $1,507

b) During 2006 fewer difficult urban projects were completed resulting in lower unit cost. Urban projects are characterized by higher tree densities on rights of way that extend through subdivisions. These rights of way generally require added community and property owner consultation, landscape planning to reduce the impacts of tree removals and more precise treatment of vegetation to meet community expectations.

School Energy Coalition (SEC) INTERROGATORY #13 List 1

Interrogatory

C1/2/2- Sustaining OM&A

C1/2/2, p. 45: Sustaining OM&A: Overhead Lines: Planned Corrective Maintenance

(a) Please provide the projected cost of the corrective work for the Sudbury-Barrie 500kV lines and the London-Sarnia circuits as well as the basis for the projections. (Provide costs for each year that the projects have been or will be underway.)

Response

(a) The costs for the Sudbury – Barrie 500 kV Lines are:

2010 - $0.3 million projection
2009 - $1.3 million projection
2008 - $1.1 million projection
2007 - $0.9 million

Projections are based on experience with the site conditions encountered during previous years and the number of structures to be addressed during the year.

The costs for the London - Sarnia 230 kV Lines are:

2010 - $4.0 million projection
2009 - $4.0 million projection
2008 - $2.1 million projected
2007 - $0.1 million

Projections are based on the number of structures to be addressed during the year.

School Energy Coalition (SEC) INTERROGATORY #14 List 1

Interrogatory

C1/2/2- Sustaining OM&A

C1/2/3: Development OM&A

(a) The Research and Development function has increased from $1.1 million in 2005 to a projected level of $9.2 million by 2010. Please provide a summary of all projects planned for 2009 and 2010, their associated costs, and any "business case" type analysis that was done to approve the project.

(b) Please provide a breakdown of the $3.1 million increase in Standards Development costs from 2007 to 2008, 2009 and 2010. What new work is being accomplished and how were the costs budgeted for the test years?

Response

(a) A summary of the initial list of 2009 R&D Projects and their associated preliminary cost estimates is provided in the table in Attachment 1. Additional projects will be added to this list during the course of the year based on need, opportunity and merits of each proposal consistent with the drivers identified in Board Staff Interrogatory Exhibit I, Schedule 1, Tab 27.

Presently, there is no list of 2010 R&D projects because these selections are made yearly. The increased budget for 2010 is based on the increased activity in Ontario and the utility industry in general, associated with the drivers and emerging issues that are described in Interrogatory Exhibit I, Schedule 1, Tab 27. The 2010 budget will include projects and initiatives being considered in the following areas:

- “Star” Gathering System Dedicated for Small Renewables – Clear Logjam
- Increase Inter-Area Transmission Capability and Cut Market Congestion with FACTS
- Wide Area Control & Measurement (PMU – Phase Measurement Unit)
- Smart Grid Development and Convergence Opportunities
- Energy Storage – Grid Application
- Large Solar Power System Integration into Power Systems
- Ensure Adequate Telecom Capability
- Renewables Industrial Park/ Hybrid Vehicles/ Mass Transit – Plan Transmission
- Robotic Helicopter for Transmission Line Condition Inspection & Monitoring

- Fleet Services Environmental Program
- Validate Wind-Generator Performance
- Energy Hub Management System
- Develop & Enhance Technical Standards
- PCB Removals, Testing Techniques & Statistical Analysis

Business Cases are not prepared for approval of R&D projects because consistent with research, development, demonstration and deployment type projects, they are selected and prioritized based on the following three merits:

- technical development – uses technical advancements via technology, processes and practices to improve or enhance the technical performance of the transmission system

- continuous innovation – demonstrates continuous innovation improvement for improving performance or delivering value

- deliver value – potential to deliver benefits and rewards to customers and shareholder now or in the future

For leveraged investments projects, the benefits of each individual project are assessed and prioritized in conjunction with other project participants.

For university related projects, the long term benefit is in providing the funding for developing future industry experts and/or addressing specific technical issues associated with the planning, maintenance, construction and operation of the transmission system.

For all other projects, once the need or opportunity is identified, the project is assessed and prioritized based on the three merits given above.

(b) A breakdown of the disciplines contributing to the increase in standards development costs is provided in the table below.

Discipline	**Standards Breakdown (%)**
Lines	15
Stations	26
Protection, Control & Telecom (PCT)	26
Other	33

The new work being carried out in 2009 and 2010 is described below:

- Develop new standards associated with new vendor equipment, especially in the Protection, Control and Telecom areas. This includes developing a fully functional design specification and standard for transformer station Protection, Control and Telecom equipment in a self contained, transportable, cubicle / building that is built and assembled by outside suppliers ("PCT in a box").

- Harmonize existing Hydro One standards and equipment/material specifications with new industry standards. The work includes updating the following: environmental approval guidelines; construction guidelines; Certificate of Approvals preparation guidelines.

- New regulatory requirements necessitate development of new standards and revised work practices. For example: arc flash worker safety requirements; new Electrical Safety Authority (ESA) requirements; develop and formalize the quality assurance (Q/A) for all equipment capital and sustainment engineering projects via a formal Inspection, Testing, Acceptance Plan (ITAP).

- New market drivers such as connection of renewable generation sources (wind, bio-digesters, etc) has resulted in the need to develop new standards to be able to streamline the work process and designs for handling a large influx of distributed generation connections. This requires updating the design and protection, control and telecom standards to accommodate two way power flows, anti-islanding issues etc.

- Updating of selected standards and development of additional standards to enable knowledge transfer before senior staff retire. This includes standards work related to: updating the Engineering Material Catalogue Standard which covers ongoing maintenance; updating the Standard Equipment and Material Specifications for engineering, material ordering and construction; use of a 3-Dimensional Model-Based Design & Drafting program that standardizes the power equipment and facilities for new connections.

The estimated cost to complete the Standards work described above is included in the budgets for 2009 and 2010.

Category	Project Title	Objective	Expected Benefits	Business Value Drivers	2009 Proposed ($K)
Asset Perf. Optimizaton	Enhancements to the AMP (Asset Management Planner)	Develop an alternative method to evaluate alternative maintenance policies and their impact on transmission system equipment.	Effectively evaluate alternative maintenance policies for major transmission equipmen	Customer, Finance, Productivity & Costs	$ 50
Asset Perf. Optimizaton	AREP (Area Reliability Evaluation Program) Enhancements	Computer code-enhancements and complete overhaul of computer program to include circuit breaker dependent and common mode outages in the algorithms.	Make AREP more flexible. Provide confidence that the technical basis of the computer program is sound, and ensure the user is comfortable using the programs with adequate documentation.	Security, Reliability	$ 90
New Technology	Flexible Optimal Power Flow Including Graphs Of Transmission Limits	(i) To develop the computational program for very flexible and intelligent OPF (FINEOPF). (ii)Develop two extra capabilities of the FINEOPF tool (contingency ranking analysis and maximum loadability analysis (iii) Develop visualization tools combining GPS information on the H1 network with the PTI-PSS/E input data files.	More rapidly carry out planning study work related to estimating the operating limits of transmission system facilities.	Customer, Finance, Productivity & Costs	$ 95
New Technology	Transmission Expansion Planning (TEP)	Develop a new methodology for planning transmission systems, which determines the optimal sequence of transmission line reinforcements. The main objective is to identify where, when and what transmission reinforcements should be placed in the power network.	More rapidly carrying out determining transmission system limits under a range of operating conditions.	Security, Reliability	$ 90
New Technology	Incorporating Process bus into IEC61850 Trial DESN	Examine the process bus solutions and incorporate them into the existing 61850 Trial DESN. Since the existing Trial DESN station includes only the station LAN, process LAN needs to be incorporated to reap the full benefits of a 61850 station.	Study the process bus approach that can lead to substantial cost savings if copper wiring from the switchyard is eliminated	Reliability, Financial	$ 100
New Technology	Develop IEC 61850 Maintenance Testing Methodology and Tools	To investigate the maintenance issues associated with testing an IEC 61850 DESN station. Develop testing methods for the station network, and the protection IEDs. Evaluate and recommend various tools or methodologies to be used to isolate, block, and test the protection IEDs and station network.	Develop IEC61850 maintenance testing methodologies and tools to allow implementation of IEC61850 at DESN stations.	Reliability, Financial	$ 100
New Technology	Fault Location	To accurately locate faults on multi-terminal lines considering mutual impedances and line sections	Improved reliability of the power system by faster fault location and subsequent repair and maintenance	Reliability, Financial	$ 85
New Technology	IEC 61850 Based Breaker Failure Protection, Performance and Testing	Design, develop and verify an IEC 61850 based breaker failure protection scheme (SEL451, C60, Brick) for EHV and HV breakers in Hydro One Networks. .	Prepare for a practical approach to migrate to IEC 61850 based Breaker Failure Protection which may lead to eliminating extensive copper wiring from the switchyard	Reliability, Financial	$ 100
Asset Perf. Optimizaton	Review of PALC workstation	Review the actual PALC workstation (functionality/performance/requirements/etc.) and determine how to create an equivalent workstation for the interim using readily available, off the shelf product	Increase life of protective/control schemes that uses the PALC and provide candidates for sparing purposes	Reliability, Financial	$ 75
Asset Perf. Optimizaton	Relay Aging	Perform accelerated life testing to predict consequences of ageing on the performance of relays under consideration. Performance deviation of original specifications will be noted	Estimate the remaining useful time of tested devices so that retrofit can be planned and prioritized accordingly to avoid forced outages and lower system reliability due to lack of spares	Reliability, Financial	$ 160
New Technology	Automating IEC61850 Design processes	Standardize and optimize the existing design procedures to accommodate IEC 61850.	Prepare for a practical design approach to streamline and automate IEC 61850 based DESN design	Reliability, Financial	$ 220
New Technology	Synchrophasor - Real Time Dynamics Monitoring System (RTDMS)	Provide Hydro One with the ability to investigate and standardize on applications for phasor measurement units. Hydro One users will be able to view the steady state and dynamic behaviour of the Hydro One grid and the Eastern Interconnection.	Enable Hydro One to investigate the applications of synchrophasor technology by using the data from the PMUs deployed across Ontario, and the broader Eastern Interconnection. Evaluating RTDMS will allow Hydro One to standardize on applications of synchrophasor technology. The project will also teach Hydro One some do's and don'ts prior to actual operationalization of synchrophasor technology	Reliability, Financial	$ 55
Asset Perf. Optimizaton	PQ Montinoring (Jan - April)	To assess the data and results of the Power Quality monitoring project	To monitor system power quality delivered to customer	Reliability, Customer	$ 11
Asset Perf. Optimizaton	Condition Assessment of Hydro One Current Transformers (CTs)	To develop a testing and inspection program that would assess the condition of CTs and identify those at risk of failure.	(i) Support maintenance activities by identifying those CTs 'at risk', to minimize possible impact on system reliability and maximize personnel safety/security in the station yard (ii) Support asset management activities by providing better data for the formulation of health indices, improve the ranking of CTs according to their condition and to support repair/replace decisions.		$ 135
Leveraged Funding	Transmission EPRI & CEATI Projects	EPRI & CEATI Projects			$ 2,100
New Technology	Ring Gap Alternative (RGA) Performance Monitoring	Evaluate the results of RGAs field trials to test the new solid state cable sheath surge protective device	Usage of RGA (Ring Gap Alternative) instead of Ring gaps in those installations where high fault currents, safety, or cable age warrant it	Safety, Reliability	$ 80
Asset Perf. Optimizaton	Middleport TS Assessment of short circuit capability of bus structures	To assess the short circuit capability of bus structures	To determine the maximum short circuit capability of bus structures	Safety, Reliability	$ 250
Universities	Universities & OCE	Tranmission University Program & Participation in Ontario Centre of Excellence		Productivity & Costs	$ 1,619
Other	Other	--			$ 585

School Energy Coalition (SEC) INTERROGATORY #15 List 1

Interrogatory

C1/2/2- Sustaining OM&A

C1/2/3: Development OM&A- Pre-Engineering work for IPSP

With respect to the anticipated $47.9 million in pre-engineering work for IPSP, the costs of which HON is proposing to track in a "variance account":

Provide any updates that HON has received from the OPA regarding these projects now that the IPSP is under review;

as there is no forecast of these expenditures in rates, confirm that the account HON is requesting should properly be called a deferral account and not a variance account.

Please explain why these costs are being treated as Development OM&A instead of development capital.

Response

The OPA has provided no updates to Hydro One with regard to any of these projects while the IPSP is under review.

Confirmed.

The characterization of these "pre-engineering" costs as Development OM&A is consistent with accounting recognition for other similar projects, as it is premature to capitalize such costs prior to a decision being made to proceed with the full project.

School Energy Coalition (SEC) INTERROGATORY #16 List 1

Interrogatory

C1/2/2- Sustaining OM&A

C1/2/4- Operations OM&A

(a) Operations costs increase from $28.4 million in 2007 to $33.1 million in 2009, a 17% increase. Please:

(i) provide a breakdown of the increased expenditures in 2009 and 2010 over 2007 by cost driver, including increased training requirements, labour escalation, and the cost of hiring new junior staff to work alongside more senior staff.

(ii) with respect to the demographic issues identified at p. 2, line 10, please provide the number of new staff who have been hired thus far.

(iii) Provide the portion of the 2009 and 2010 budgets for Operations that is made up of the cost of new hires being trained alongside senior operators?

Response

(i) The following table shows the cost breakdown of total training costs, which includes the cost of hiring new junior staff. New junior staff is considered to be a training cost until they become fully qualified.

Years	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**
Train and Mentor Junior Staff	0	1.1	1.7	2.8	3.6	2.7
All other Training Costs	0.3	2.0	0.9	1.2	1.2	1.2
Total	0.3	3.1	2.6	3.9	4.8	3.9

The inflationary increases from 2005 to 2010 are described in Exhibit A, Tab 14, Schedule 2. Over the 2005 to 2010 period, the composite wage and material escalation for transmission O&M is estimated to be about 13%.

(ii) Forty new staff has been hired as of Dec. 2009.

(iii)See response to (i).

School Energy Coalition (SEC) INTERROGATORY #17 List 1

Interrogatory

C1/2/2- Sustaining OM&A

C1/2/8- Shared Services: Asset Management

The Asset Management budget increases substantially in 2009 over historical levels. The evidence generally describes the work of each line item and provides some general explanations for the increase in costs, but does not provide a specific explanation as to how the increased budgets were arrived at.

(a) Therefore, for each of the line items in Table 1 (Strategy & Business Development, System Investment, etc.), please provide an explanation as to how the increase in expenditures from 2007 to 2010 will be spent, using a bottom-up approach. For example, what additional work is forecast (over 2007 levels) and how was the cost of that new work forecasted? Please break down the costs by, for example, incremental labour costs, facilities costs, etc.

(b) For incremental labour costs, please provide an analysis of the anticipated number of additional staff dedicated to the asset management functions and what functions they will be performing.

Response

(a) The increase in costs from 2007 to 2010, is related to additional efforts and activities to support the effective delivery of Asset Management activities, including the development of asset strategies and investment plans for the Transmission business consistent with Corporate Strategy and Objectives.

In general, the Asset Management cost increases are primarily driven by:

- Increased Transmission OM&A and Capital work programs resulting in the need for Asset Management to develop system planning documents, which drive the execution of work.
- Increased regulatory work related to rate hearings, facility approvals, Environmental Assessment proceedings, NERC and, NPCC requirements.
- Increased work requirements associated with Pre-IPSP projects, near-term projects included in the IPSP and support for IPSP approvals.
- Compliance activities including Bill 198 programs, IESO compliance related programs precipitated by local Market and NERC requirements.

- Succession planning / demographics planning (i.e. dealing with large volume of planned and actual staff attrition) and pre-hiring to provide over-lap with experienced staff to ensure business continuity.
- The Cornerstone project which requires experienced staff to ensure business processes will be streamlined to improve business efficiency.

More specifically, the reasons for the increases in key contributing units are due to:

Strategy & Business Development: (Increased by $3.8M)

- Increased activities to support development and delivery programs related to strategy, conservation, business development, smart meters and smart network.
- More detailed underlying activities can be seen in Exhibit C1, Tab 2, Schedule 8, page 6.
- OPA-funded CDM programs for 2009 and 2010 are not included in Hydro One Transmission's revenue requirement submission.

System Investment: (Increased by $14.8M)

- Increased planning and planning related documents related to system development due to IPSP recommendations, local load growth and new generation (not necessarily generation connections on the distribution system)
- Increased levels of plans to address escalating asset sustainment needs due to aging infrastructure
- Increasing planning & processing requirements to support a growing number of generation connection applications. (Hydro One received approximately 20 – 30 applications per year in 2004 – 2005, whereas from 2006 to the end of February 2008 we have received approximately 1,800 applications for either Initial Feasibility Assessments or full Connection Impact Assessments (CIA) of which approximately half require full CIAs. 448 projects that are within Hydro One's thresholds, are due to have CIAs completed.)
- Increased planning, monitoring and reporting activities in response to a growing number of reliability standards and compliance requirements
- Increased planning and planning related documents relating to enhancement of System Investment deliverables (e.g. initiatives to maximize project and program execution through such means as multi-year releases).
- Support for increased regulatory activities, orders and expectations.
- Increasing work to prepare and transition to new Cornerstone systems.
- Training new staff for succession planning initiatives.

Work Program Optimization: (No Increase)

- Although, there is no forecast increase in spending in this area, there will be increased activities relating to Transmission capital program, expansion of knowledge management system, and the support of future Cornerstone phases.

Increased productivity has been enabled in the Work Program Optimization group as a result of Cornerstone Phase One implementation.

Business Integration: (Increased by $4.5M)

- Additional planning and reporting activities related to higher levels of and greater complexity of work programs in the Transmission and Distribution businesses,
- Increased activity in the deployment of the time reporting changes in the field.
- Increased activity in the area of information assets, in terms of keeping track of detailed changes in the system configuration.
- Requirement to support the Cornerstone initiative on an on-going/production basis.

Business Transformation: (Decreased by $0.1M).

Real Estate and Facilities: (Increased by $11.6M)

- Increased activities, primarily new space – accommodation requirements, driven by the increasing work programs across the company, and the expansion of real estate and facilities work programs.
- Investments to ensure facilities continue to meet health and safety requirements.

Contract and Business Relations: (Increased by $1M)

- Increased investments to improve the level of customer service that the company provides to its customers, consistent with corporate strategy. Customer service is one of the company's key objectives. The main focus here is on Large Customer segments, such as; Transmission-connected industrial customers, Local Distribution Companies and Transmission-connected generators.

Asset Management Processes and Policies: (Increased by $1.4M)

- The Asset Management Processes and Policies function was part of System Investment prior to 2008
- Increased activities; developing the long-term asset plans, developing and improving policies and procedures, supporting Cornerstone initiative, developing and improving regulatory-related processes within Asset Management, and supporting improvements to market rules and codes. These increased activities have also resulted from increases in Transmission and Distribution work programs.

To understand how work is forecasted for the above areas, please refer to Investment Plan Development Process, in Exhibit A, Tab 14, Schedule 4.

To understand how cost of work is forecasted for the above areas, please refer to Costing of Work, in Exhibit C1, Tab 4, Schedule 1.

(b) The Anticipated number of net additional staff dedicated to the Asset Management Functions is included in the table below.

	Bridge	**Test Years**	
	2008	2009	2010
Total	61	17	11

The responsibilities that will be undertaken by the staff in areas mentioned in Exhibit C1, Tab 2, Schedule 8, Table 1, can be seen on the following pages of the same exhibit:

Strategy and Business Development – pages 6 to 7.
System Investments – page 8 to 9.
Work Program Optimization – pages 10 to 11.
Business Integration – pages 12 to 13.
Business Transformation – page 14.
Real Estate and Facilities – pages 15 to 17.
Contract and Business Relations – pages 19 to 20.
Asset Management Processes and Policies – page 21.

School Energy Coalition (SEC) INTERROGATORY #18 List 1

Interrogatory

C1/2/2- Sustaining OM&A

18 C1/2/8, pg. 15- Shared Services- Real Estate & Facilities: with respect to the Real Estate & Facilities function, please provide a detailed breakdown of the new facilities and their cost as well as the increasing work programs that have led to an $9 million increase in this budget over 2007 levels. For example,

(a) What new facilities are being added, and what is the associated cost?;

(b) What specific new work activities are planned, and what are the costs of each?

Response

a) New facilities include leased office space primarily within the GTA Region at the following locations. The total estimated annual cost is approximately $5.0 million.

- Office space @ Atrium on Bay, (20 Dundas West, Toronto)
- Additional Office space @ Trinity, (483 Bay Street, Toronto)
- Office space @ Meter Reading & Relay Services Facility, (6135 Danville Rd, Mississauga)
- Office space @ 95 Mural Street, Richmond Hill

b) Real Estate work program expansion includes acquisition activities in support for Hydro One transmission development work and management of real estate rights in relation to corridor leasing activities. The total real estate work program cost increase from 2007 to 2009 is estimated at approximately $2 million.

The expanded facilities work program responds to current work space accommodation needs which includes management of the leased facilities portfolio and overseeing facilities new construction, renovations and building additions projects. The total facilities work program cost increase from 2007 to 2009 business is estimated at approximately $7 million which includes new facility additions at the cost of approximately $5 million – as specified above in response (a).

School Energy Coalition (SEC) INTERROGATORY #19 List 1

Interrogatory

C1/2/9: Shared Services- Information Technology

Preamble: IT costs increase by $23.9 million in 2009 over 2007, a 25% increase.

IT: Sustainment costs increase by $15.8 million, or 25%, in 2009 over 2007. At p. 2, HON states that a portion of the increase is due to the Cornerstone Phase 1 and 2 projects moving from project status to "in-service", which means the costs to sustain the applications move to Sustainment OM&A costs. Please:

(a) specify what portion of the increase in IT: Sustainment is due to having Cornerstone project move to in-service costs;

(b) provide a summary of the cost increases in IT: Sustainment that are not related to the Cornerstone project.

Response

a) The costs associated with having Cornerstone Phase 1 move to sustainment in 2009 are $6.3 million or 40% of the increase in sustainment costs as compared to 2007

b) The remaining 60% increase in sustainment costs from 2007 to 2009 of $9.5 million are comprised as follows:

i. Cost of Living increase (see also Exhibit I, Tab 6, Schedule 35) payable pursuant to Inergi contract ($4.4 million)

ii. Net change in administered and managed contracts. Contracts are for hardware maintenance, software licence and support fees ($4.4 million)

iii. Net changes to service levels and costs in Inergi contract including volume and service changes ($0.7 million)

School Energy Coalition (SEC) INTERROGATORY #20 List 1

Interrogatory

C1/2/2- Sustaining OM&A

20. Ex. C1/2/9: Shared Services: Business Telecom: With respect to the Business Telecom IT budget, please provide a breakdown of the extra $3.2 million forecast for 2009 over 2008 levels (an 18% increase), as follows:

(a) What proportion is due to the increased size of the HON workforce? How many new employees does that represent?

(b) What proportion is due to increase in costs for services provided by Hydro One Telecom and Bell?

(c) What other factors contribute to the increase?

Response

a) The portion of the increase in Business Telecom costs due to the increase in workforce is $1.1 million or 34% of the increase. The increase in employees includes increases in the HONI, Inergi, and Vertex workforces (pursuant to the Inergi agreement Hydro One provides telephony and computer equipment and services), consultants and 3rd party contractors working in Hydro One offices on Hydro One projects such as Cornerstone, Smart Meters, Cyber Security, NMS replacement etc..

In arriving at the estimated costs for 2009 we have assumed a Hydro One headcount of 7,000 employees, and 700 Inergi and Vertex employees. We have not accounted for contractors or 3rd party consultants that might be used on various projects (i.e. Cornerstone) and have estimated the number of minutes used for the assumed headcount. Actual costs are based on usage and number of minutes used.

b) The total increase in costs provided by Hydro One Telecom and Bell is $1.8 million or 56% of the increase. The increase in Hydro One Telecom costs are $0.4 million pursuant to the contract. For Bell an estimated increase of $1.4 million has been included as a result of the end of contract. The increase is for: the RFP process; contract negotiation and transfer; site orientation and training required to transition the Bell contract to a new provider should such an award be made (further detail available in EB-2008-0272, Exhibit C1, Tab 2, Schedule 9, pg 18).

c) The balance of $0.3 million (10%) consists of items such as the provisioning of 2 new office locations

School Energy Coalition (SEC) INTERROGATORY #21 List 1

Interrogatory

21. C1/2/9: Shared Services: IT Management & Project Control increases by $4.9 million in 2009 over 2007 (a 73% increase over two years). The pre-filed evidence provides a general description of the work to be performed in 2009/2010 but no specific explanation for the large increase over historical levels. Therefore:

(a) Please provide a breakdown of how the additional $4.9 million over 2007 will be spent, including what new work is planned and how that new work has been budgeted (incremental labour costs, overhead, etc.).

Response

a) The increase of $4.9 million in IT Management & Project Control is comprised as follows:

The IT Management increase of $0.7 million relates to the addition of a QA/QC person and a project management person and due to increases in staff costs since 2007.

The project support and control increase of $4.2 million relates to work associated with the following projects:

- Architecture design and planning for:
  - assessment of desktop performance and image design
  - assessment of active directory redesign
  - portal strategy development
  - DR strategy and process development Phase 3 (outlook, exchange, ihub)

- Desktop and outsourcing contract:
  - desktop upgrade program management and pilot rollout- IE6, Outlook 2007, office 2007
  - purchase of non capitalized general software to replace custom applications
  - end user training and self serve automation software
  - service level definitions for outsourcing contract renewal

- Infrastructure
  - information lifecycle management deployment to storage area network (SAN)
  - Windows 2007 OS program developments and migration strategy
  - decommissioning of applications and databases from Cornerstone

- Security:
  - security log consolidation and monitoring
  - audit and compliance services
  - database application for tracking security and virtual monitoring

- Other
  - Gartner
  - training and education costs

Project support and control costs are estimated based on an assessment as to whether a project will be done by a 3rd party vendor (for example Microsoft windows technologies), using contract staff (architecture design and planning, outsourcing) or by Inergi. Estimates are based on past experience with similar projects and with input from IT analysts such as Gartner. Projects are developed through an annual planning session.

School Energy Coalition (SEC) INTERROGATORY #22 List 1

Interrogatory

C1/2/2- Sustaining OM&A

C1/2/12: Property Taxes: Please explain the projected increase in property taxes for Transmission Lines from $38 million in 2007 to $42.2 million in 2009.

Response

The forecast expenditures of $42.2 million in 2009 in property taxes for Transmission Lines are based on the following assumptions:

- an annual 2% municipal tax increase
- no increase in assessed value of Hydro One properties for 2007 & 2008 as re-assessments were cancelled by the Province (Municipal Property Assessment Corporation)
- an increases in property taxes of 2% for 2009 as result of re-assessment.

The actual property tax expense in 2007 of $38 million for transmission lines reflects property tax payments less tax refunds received. (In 2007, Hydro One received one time refunds from municipalities for tax years 2002-2007 inclusive, resulting from Assessment Review Board decisions and corrections to the acreage of Hydro One Utility Corridors.)

School Energy Coalition (SEC) INTERROGATORY #23 List 1

Interrogatory

C1/3/1 and C1/3/2: Corporate Staffing and Compensation

(a) Please provide a breakdown of Table 3 at C1/3/2, p. 10 by major employee groups (PWU, Society, MCP, Hiring Hall) and a further breakdown by compensation components (base salary, overtime, benefits, incentive compensation, etc.)

(b) If possible, please provide the component of Table 3 at C1/3/2, p. 10 that applies to the Transmission business.

(c) Please provide the number of employees in each employee group for the years 2005-2010 (preferably FTE, but if that is not possible, end of year) for the years 2005-2010.

Response

a) Please refer to Exhibit I, Tab 1, Exhibit 19

b) Please refer to Exhibit I, Tab 1, Schedule 35, part b).

c) FTE data is not available. Please refer to Exhibit I, Tab 1, Exhibit 19, for head count numbers by representation group.

School Energy Coalition (SEC) INTERROGATORY #24 List 1

Interrogatory

C1/3/1, pg. 3: Apprentice and Graduate Training Programs

(a) Please provide a chart showing the number of new hires and graduates from the Apprentice and Graduate Training programs for the years 2004-2010.

(b) Please provide the cost of the program for each year.

Response

(a) **Graduate Training Program Hiring**

Year	2004	2005	2006	2007	2008	2009	2010
# Hired	21	29	0	0	80	73	50

Apprentice Hiring

	2004	2005	2006	2007	2008	2009	2010
Lines	48	48	48	80	63	48	48
Forestry	0	26	29	88	55	25	38
Stations	25	17	14	25	29	28	28
Mechanical	0	0	2	3	4	2	2
Millwrights	3	0	0	4	3	0	0
Construction Lines	6	31	14	40	28	25	25
Construction Electrical	13	8	22	27	33	30	30

(b) Cost of the Graduate Training program would include some portion of the salaries and benefits for each new employee plus nominal administration costs for Human Resources to run the recruitment program (estimated $50k). New Graduates are hired onto the new lower Society wage schedule.

The cost of the apprenticeship program would include some portion of the salaries paid to the apprentice. Hydro One also received a tax credit for each apprentice hired. For both programs, after some short initial introductory training when they start their employment, trainees/apprentices are used for productive work on an almost continuous basis, with some interruptions to do some classroom and/or field training. For example, in the case of apprentices, they are doing work which would otherwise be completed by higher paid tradespersons. Likewise, work performed by new grads would otherwise be performed by MP2 or MP4 Society employees. As such, it is impossible to estimate the true cost of these programs. However, these programs are cost effective given that we assign trainees real work which is commensurate with their skill level.

School Energy Coalition (SEC) INTERROGATORY #25 List 1

Interrogatory

C1/2/2- Sustaining OM&A

A/16/2: Compensation and Productivity Benchmark Studies

A/16/2, pg. 3: HON states in the pre-filed evidence that the "benchmarking study results provide further support for Hydro One's position that its continued productivity accomplishments offset its relative compensation levels."

(a) Please confirm that this statement reflects Hydro One's position and is not necessarily that of Mercer/Wyman.

(b) Given that its compensation levels are, on average, 17% above the median level, does HON agree that in order to be offset by higher productivity, HON's productivity levels would also have to be significantly above the median?

(c) It does not appear as though the Mercer/Wyman report looked at productivity on a position by position basis. Therefore, does HON agree that the results do not necessarily provide a justification (in terms of higher productivity) for particular employee groups that are above the market median for compensation?

Response

(a) The statement "benchmarking study results provide further support for Hydro One's position that its continued productivity accomplishments offset its relative compensation levels." is a statement made by Hydro One and reflects Hydro One's position. It is based upon and supported by the conclusion reached by Mercer/Oliver Wyman in their study, Exhibit A, Tab 16, Schedule 2, Attachment 1 page 2, and quoted in A/16/2, pg. 3: "examining the mix of [productivity] indicators leads to the conclusion that Hydro One requires less workforce compensation to generate various units of output".

(b) No Hydro One does not agree with the inference drawn in the question. There are a number of factors that can drive compensation levels, productivity being one of them. Also affecting compensation are geography, history, customer service and satisfaction, safety, reliability. There is no set "one size fits all" formula to determine what an appropriate offset to higher compensation levels might be.

(c) No. Hydro One does not agree with the conjecture that the results do not necessarily provide a justification. Mercer/Oliver Wyman did not use position by position compensation for the productivity portion of the study; this was clearly impractical and not possible in the real world. Applying the question's logic, no survey or benchmarking study would be valid unless 100% of the population was sampled and discretely analyzed. The productivity benchmarking results are indicative based on the total compensation for the whole of each company and are thus comparable for all employee groups within a company.

School Energy Coalition (SEC) INTERROGATORY #26 List 1

Interrogatory

C1/2/2- Sustaining OM&A

Ex. A/16/2, Attachment 1 (Mercer/Wyman Study)

(a) For each of the benchmarks used (T&D Compensation per MWh sold, T&D Compensation per Gross Asset Value, T&D Compensation per KM of Line, etc.) please provide the value for HON using 2009 data.

(b) To the extent possible, please provide the numerator and denominator values used to derive the values for each comparator in Tables 9-12 of the Productivity study.

(c) How did Mercer/Wyman define "Customer Service compensation"?

(d) Do the numerator and denominator for the Customer Service benchmarks for HON (Tables 14-17) include the Transmission business? If so, would these numbers not be skewed by the fact that the Transmission business is allocated a very small proportion of overall customer care costs?

Response

(a) The productivity indicators used in the Mercer/Wyman Study are based on actual values(e.g. MWh sold) for Hydro One and the peer group used for comparisons. As such, 2009 data for the calculation of these indices are not yet available.

(b) The values cannot be provided because they would violate the confidentiality provisions of the survey.

(c) “Customer service compensation” was defined as total compensation costs for staff performing customer service functions including call center, billing, collections, credit calls, meter reading, new connects, disconnects.

(d) Both the numerator and the denominator include transmission and distribution numbers for all companies in the panel. All companies in the panel have substantial transmission assets so any skewing would depend on potential allocation differences across companies.

School Energy Coalition (SEC) INTERROGATORY #27 List 1

Interrogatory

C1/2/2- Sustaining OM&A

C1/4/1: Costing of Work

(a) Please explain the 73% increase in the cost of Field Supervision and Technical Support between 2005 and 2010;

(b) Please explain the 65% increase in the cost of Support Activities between 2005 and 2010.

(c) Pg. 14: What assumptions regarding the cost of fuel did HON make for its forecast of 2009/2010 Fuel cost shown in Table 3? Does HON believe those assumptions should be revised in view of the recent dramatic reduction in the cost of fuel?

Response

(a) Exhibit C1, Tab 4, Schedule 1, Table 1, page 2, provides a breakdown of Standard Labour rate composition for a Stations Regional Maintainer- Electrical into the underlying cost elements over the over the historic, bridge and test years.

Field Supervision and Technical Support cost is shown to increase by 79% (not 73%) from 2005 to 2010. Prior to 2008, Field Supervision and Technical Support was partially directly charged to OM&A and partially charged as a cost element in the labour rate composition of a Stations Regional Maintainer – Electrical. For 2008 and beyond, Field Supervision and Technical Support is 100% allocated to the labour rate composition for Stations Regional Maintainer-Electrical to better align to the nature of the work they perform, this is a refinement in cost recognition.

In addition to the refinement of cost recognition for Field Supervision and Technical Support, the other main contributors to the increase are:

- Increased resources to ensure compliance with corporate policies and procedures resulting from the Provincial Auditor General's audit of the corporation in 2006, and
- Payroll burden escalations.

(b) Support Activities cost is shown to increase by 66% (not 65%) from 2005 to 2010.

Prior to 2008, Support Activities was partially directly charged to OM&A and partially charged as a cost element in the labour rate composition of a Stations Regional Maintainer – Electrical. For 2008 and beyond, Support Activity is 100% allocated to the labour rate composition for Stations Regional Maintainer-Electrical to better align to the nature of the work that is performed, this is a refinement in cost recognition.

In addition to the refinement of cost recognition for Support Activities, the other main contributors to the increase are:

- Increased focus to develop the Health, Safety and Environment work program. This increase is to ensure compliance with Occupational, Health and Safety Legislations, Policies and Standards, in line with corporate strategy and objectives, and
- Increased resources towards Work Methods and Training. This includes the costs to design, develop, and deliver work methods and training programs.

In general, Hydro One seeks to reduce labour rates when opportunities are available. Please see Exhibit A, Tab 16, Schedule 2, for a listing of labour related cost efficiencies. Hydro One remains committed to lowering its overall compensation costs, while increasing its flexibility to run an efficient operation.

(c) Fuel prices have shown extremely high volatility over the past year, rising to unprecedented levels, and decreasing with the decline in the economy. Throughout this time, we have reviewed our assumptions and feel that they remain appropriate, and that any adjustment at this time would not be warranted.

School Energy Coalition (SEC) INTERROGATORY #28 List 1

Interrogatory

Rate Base and Capital Expenditures

Ex. D1/2, p. 1: In-Service Capital Additions

The variance in 2008 was approximately 13% of the OEB approved level of in-service additions ($73.1 million of $577.8 million). In-service additions for 2009 and 2010 are forecast to be 57% and 90% higher, respectively, than the 2008 projected actual. Capital expenditures in 2007 were 27% lower than Board approved amount [see Ex. D1/3/1, pg. 4] and in 2008 they will be 12% lower.

(a) How will HON ensure that its 2009 and 2010 work programs are reasonably proximate to their projected levels given the problems HON has encountered in 2007 and 2008 [as set out at Ex. D1/3/1]

(b) Please identify any risks that HON has identified that may cause its 2009 and 2010 in-service additions to be lower than anticipated.

(c) What would the 2008 and 2009 revenue requirement impact be assuming 2009 and 2010 in-service additions are 15% lower than the level projected?

Response

To clarify, as per Tables 2 and 3 in Exhibit D1, Tab 3, Schedule 1, the Capital expenditures in 2007 were 21% lower than the Board approved level (152.1/711.6). In 2008 Capital expenditures are projected to be 11% lower than Board approved levels(81.5/774.4)

a) Hydro One is working to ensure that it can deliver the 2009 and 2010 work programs by adopting the work execution strategy outlined in Exhibit A, Tab 14, Schedule 7 pages 6-9. The strategy includes taking action on the following key initiatives:
   - Increased Work Bundling
   - Standardized Designs
   - Multi-year Work Programs
   - Long Lead Material Tracking
   - Resource Modeling
   - Turnkey Contracts
   - Targeted Resource Increases

- Continued development of University Training Programs

The planned actions are the result of lessons learned in 2007 and 2008, and will enable Hydro One to deliver the work program for 2009 and 2010.

b) As described in a) Hydro One is actively working to mitigate the risks to completing the 2009 and 2010 work program. These risks arise from external factors which include possible delays in receiving major Equipment and Materials, the potential for system outage cancellations, and delays in getting the necessary approvals (e.g. Environmental assessments, Section 92 , property rights, customer agreements).

c) It is assumed that the question refers to 2009 and 2010 revenue requirement, not 2008 and 2009 as stated.

Hydro One Transmission uses sound decision making processes to plan and execute the work program and does not forecast a reduction of 15% for in-service additions. And as noted in Exhibit I, Tab 2, Schedule 18, part c), as with all forecasts, there will be components of the test year forecasts that will be higher or lower than forecast. It is inappropriate to look at the impact on revenue requirement of a change in only one component of the test year forecast without consideration of changes in other forecast elements.

However, for illustrative purposes, if the 2009 and 2010 in-service additions were 15% lower than projected, revenue requirement in 2009 would be lower by $5.1M and revenue requirement in 2010 would be lower by $18.2M.

School Energy Coalition (SEC) INTERROGATORY #29 List 1

Interrogatory

Rate Base and Capital Expenditures

Ref. Ex. D1/2.1, Asset Condition Assessment by Hatch International Ltd.

(a) Has Hatch International Ltd. or any of its subsidiaries bid on or been selected to perform the work, or act as project manager, on any of the capital projects planned by Hydro One? If so, please advise which projects.

(b) Please explain how the results of the Asset Condition Assessment were used in preparing HON's capital budget for the test years. What specific components of the capital budget were developed as a result of the findings of the Asset Condition Assessment?

Response

(a) In 2005 and 2006, Hatch International was commissioned by Hydro One to undertake various engineering tasks. Since then Hatch have not responded to any of our publicly issued Request for Proposals (RFPs) relating to our capital projects.

At the present time, Hatch is providing civil engineering services to Siemens who hold the general contract for the replacement of Synchronous Condenser C7 at Lakehead TS. This capital work is currently in-progress.

(b) Asset Condition Assessment is one factor in developing the sustainment capital plans for Hydro One. Other factors influencing the development sustainment capital are described in interrogatory response I-6-51.

School Energy Coalition (SEC) INTERROGATORY #30 List 1

Interrogatory

Rate Base and Capital Expenditures

D1/3/2: Sustaining Capital

(a) Pg. 6: Copper theft issues: the evidence states that HON is spending $30.5 million in 2008 on improved security to address the increase incidence of copper theft.

(i) What is the value of the copper stolen from HON annually?

(b) Circuit breakers: how many breakers (oil and metaclad) will be replaced in 2009 and 2010?

(c) Please provide the expenditures for each of Oil Circuit breakers and Metaclad breakers for 2005 to 2007 (Table 3 provides a breakdown for 2009 and 2010 only)

(d) The Investment Summary Document for Oil Circuit Breaker Replacements (S1) states that performance has improved from 1997-2004 "since the onset of annual replacement and refurbishment programs." The test year budgets, however, propose a large increase in expenditures, from an average of $1.6 million from 2005-2007, to an average of $16.9 million from 2008-2010 (although this is for Circuit Breakers as a whole). Please explain why the steady level of replacement in the years 2005-2007 is insufficient going forward.

Response

a) The annual loss due to copper theft is calculated to be about $2 M /year, consisting of what is stolen and what is needed to replace it. This does not capture other related costs such as productivity lost time, station maintenance and emergency repairs costs, costs due to delays in priority work programs and any transmission/distribution revenue losses related to outages. The key drivers for this program include personnel and equipment safety, reliability and integrity of the power system, operability and maintainability of station assets.

b) Hydro One plans to replace 13 and 15 oil circuit breakers in 2009 and 2010 respectively, and 7 metalclad breakers in each of 2009 and 2010.

c) The expenditures for Oil Circuit breakers and Metalclad breakers from 2005 to 2007 are shown in the following table.

		2005	2006	2007
Oil Circuit Breaker Replacement	$M	1.5	2.3	0.4
Metalclad Breaker Replacement	$M	2.6	3.5	1.2
Total - ($) Million		4.5	5.8	1.6

Expenditures shown in the table above are for breakers replaced under the Circuit Breaker and Station Re-Investment categories. Table 3 of Exhibit D1, Tab 2, Schedule 2 only covers Metal Clad Circuit Breaker Replacement in the GTA for which there was no expenditures from 2005 to 2007.

d) A large portion of oil circuit breakers still remain on the Hydro One system. Hydro One is prudently managing the risk of having a large quantity of these technically obsolete assets on its system. The previous replacement rates do not meet Hydro One's long term objective to remove the oil circuit breakers from the system.

School Energy Coalition (SEC) INTERROGATORY #31 List 1

Interrogatory

Rate Base and Capital Expenditures

Ex. D1/3/2- Sustaining Capital- Station Re-Investment

(a) How much of the test year budget is due to "de-merger" of Hydro One-owned transmission facilities from facilities owned by Ontario Power Generation? Why is the "de-merger" necessary?

Response

The demerger is necessary as it was mandated by the Electricity Act 1998. On April 1, 1999 the demerger became effective and resulted in the assets of Ontario Hydro being allocated to the successor companies including Hydro One and OPG.

The switchyards at generating stations were designed by Ontario Hydro with some critical Transmission components such auxiliary power supplies, compressed air systems, and in some cases the protections and control systems, located in the generating power house. As these systems were still in good condition in April 1999, it was decided to leave them in place until they reached end of life.

The amount budgeted in the test years for demerger activities is $1 M, which are included in the cost for the following projects referenced in Exhibit D2, Tab 2, Schedule 3: Abitibi Canyon SS and Pinard TS (S3), Beck #1 SS (S4), and Beck #2 (S6).

School Energy Coalition (SEC) INTERROGATORY #32 List 1

Interrogatory

Rate Base and Capital Expenditures

Ex. D1/3/2: Sustaining Capital- Power Transformers

(a) What portion of the transformer budget is for "unplanned (demand) capital replacement of failed transformers? How does this differ from the years 2005-2007?

(b) The evidence at pg. 20 refers to the design life of a power transformer as being 40-60 years. Is this what HON refers to as the end of life region? Can HON provide a narrower time frame to forecast when major repairs and/or replacement of transformers normally occurs?

(c) Figure 6 on pg. 21 does not show a significant increase in the number of transformers entering the "end of life" region in 2009 and 2010 over past years.

(i) Is the doubling in capital expenditures for power transformers due to age issues or performance?

(ii) Please provide a table showing the relevant performance metrics of HON's power transformers from 2005 to 2008.

Response

a) Hydro One provides for failed transformers in two ways:

i) Purchasing spares to replenish the transformer spare pool or to build the spare pool to a level required to meet the failure trends within a specific transformer family.
ii) Carrying funding in specific line item to be used to replace transformers in current year.

The portion of the transformer budget for "unplanned" (demand) capital replacement of failed transformers for 2009 and 2010 is about 46% and 37% respectively. The portion of the transformer budget for "unplanned" (demand) capital replacement of failed transformers for 2005, 2006 and 2007 is about 51%, 28% and 68% respectively.

b) A power transformer is considered to be in the End of Life region when it has reached more that 75 % of its expected useful life. This is equal to 49 years. Hydro One cannot provide a narrower time frame to forecast when major repairs and/or replacement of transformers normally occurs because individual transformers are deemed to be at their end of life based on condition and performance data and are selected for replacement through the investment plan prioritization process.

c)

i) Hydro One does not replace assets based on age. Hydro One's spending on transformers is based on many factors as discussed in Exhibit D1, Tab 3, Schedule 2, page 19 to 22, Section 3.3.2 "Investment Plan Process".

ii) A table showing the relevant performance metrics of Hydro One's power transformers is provided below. Figures are actual forced outage performance of power transformers by year and by voltage class. The relevant performance metrics used include outage frequency and unavailability. Definitions of these measures are provided below.

	Hydro One					
	2005		2006		2007	
Voltage	Freq	Unavail	Freq	Unavail	Freq	Unavail
115 kV	0.27	35.8	0.23	36.5	0.30	24.3
230 kV	0.23	23.9	0.20	16.0	0.21	13.0
500 kV	0.82	167.7	0.73	238.5	0.80	86.5

<u>Frequency of Forced Outage Performance</u>
This value represents the number of forced outage events experienced per equipment unit per year.

<u>Unavailability of Forced Outage Performance</u>
This value represents the extent to which the equipment is not in service and measured as hours per unit per year.

School Energy Coalition (SEC) INTERROGATORY #33 List 1

Interrogatory

D1/3/3- Development Capital

(a) What is HON seeking from the Board in this proceeding with respect to Category 4 projects?

(b) Please provide a list of Category 2 and 3 projects (including their respective cash flow during each of the test years and total cost) that were already considered by the Board in a previous proceeding.

Response

(a) As stated in Exhibit D1, Tab 3, Schedule 3, page 9, lines 22 to 27, Category 4 projects will require future project-specific approvals from the OEB in the form of Section 92 applications. Hydro One is simply informing the Board of all components that make up Hydro One's capital expenditures in the test years. Category 4 projects do not impact the test years' revenue requirement as they will only go in-service beyond the test years. Thus, approvals for these projects are not being sought in the current application.

(b) Below are the lists of Category 2 and 3 projects that were already considered by the Board in the previous Proceeding EB-2006-0501.

Category 2 Projects

Item #	Investment Description	Test 2009 ($M)	Test 2010 ($M)	Gross Total Cost ($M)
D3	Installation of Seven 230kV Capacitor Banks in Southwestern Ontario	34.2	0.0	56.5
D4	Bruce Special Protection System Modifications for Bruce Area	4.0	1.7	5.8
D5	Cherrywood TS x Claireville TS: Unbundle 500kV Circuits	40.4	46.9	107.3
D6	Installation of Static Var Compensator at Lakehead TS	10.1	5.4	22.5
D7	Northeast Transmission Reinforcement: Installation of Static Var Compensators at Porcupine TS & Kirkland Lake TS	48.5	54.8	108.6
D8	Installation of Series Capacitors at Nobel SS	34.2	7.2	47.2
D23	Kingston Gardiner TS: Add Transformation Capacity	6.0	0.0	14.3
D24	Holland TS: Build new 230/44kV TS & Line	6.1	0.0	26.2

Item #	Investment Description	Test 2009 ($M)	Test 2010 ($M)	Gross Total Cost ($M)
	Connection			
D26	Vansickle TS: Increase capacity to supply new load	10.4	5.9	16.3

Category 3 Projects

Item #	Investment Description	Test 2009 ($M)	Test 2010 ($M)	Gross Total Cost ($M)
D13	Installation of 350MVar Static Var Compensator & two 27kV, 150MVar Reactors at Nanticoke TS	15.2	44.4	80.0
D14	Installation of 350MVar Static Var Compensator at Detweiler TS	13.1	38.5	69.2
D32	Build New 230/28 kV TS & Line Connection in Northern Mississauga	2.0	25.7	36.1
D33	Enfield TS: Add Transformation Capacity	0.4	18.3	25.6

Gross Total Cost: *The total plan cost, including the sum of the cash flows in the years before 2009 and after 2010 and the amount of customer contribution, where applicable.*

School Energy Coalition (SEC) INTERROGATORY #34 List 1

Interrogatory

Rate Base and Capital Expenditures

Exhibit G: Cost Allocation

(a) Please provide a definition of which customers fit into each of the four rate pools.

Response

(a) A detailed explanation of which customers are charged the three main rate pools is presented in Exhibit H, Tab 3, Schedule 1: Charge Determinants. The customers which are charged for Network, Line Connection and Transformation Connection services are outlined in Sections 3, 5 and 7, respectively.

Further, the customers who are charged the Wholesale Meter Service is described in Exhibit H2, Tab 2, Schedule 1, under the Applicability section.

Pollution Probe (PP) INTERROGATORY #1 List 1

Interrogatory

Issue 4.1: Are the proposed 2009 and 2010 Sustaining and Development and Operations capital expenditures appropriate, including suchfactors as system reliability and asset condition?

1. Does Hydro One's existing transmission infrastructure limit the installation of bi-. directional distributed generation (e.g., renewable energy and/or combined heat and power plants) in downtown Toronto? If so, please provide a qualitative and quantitative (i.e. in MW) description of these limitations.

Response

The amount of generation that can be accommodated in the area is constrained by the short circuit rating of 115kV equipment of the Leaside TS and Hearn SS in the east and Manby TS in the west.

The Ontario Power Authority has provided a transmission constraints matrix that specifies the maximum amount of generation that can be connected at different locations on the system as part of the CHP-2 RFP for additional generation. This limits new generation to 70 MW in the Manby area and 20MW in the Leaside area (which includes Hearn). These limits apply to all new generation with the exception of micro (i.e., < 10 kW) solar.

Pollution Probe (PP) INTERROGATORY #2 List 1

Interrogatory

Issue 4.1: Are the proposed 2009 and 2010 Sustaining and Development and Operations capital expenditures appropriate, including such factors as system reliability and asset condition?

2. Please describe Hydro One's proposed activities and budgets in 2009 and 2010 to remove transmission constraints with respect to the installation of distributed generation in downtown Toronto.

Response

For 2009-2010, Hydro One will be carrying out project development work associated with identifying the feasibility and scope of work required to upgrade the short circuit rating of Manby TS, Leaside TS and Hearn TS, which will mitigate the constraints to the installation of distributed generation in downtown Toronto.

A total of $450K is budgeted for development work regarding Manby and Leaside over the next two years. The estimate for the work at Hearn is currently being developed, but this work is expected to be done during the 2009-2010 time frame and will be accommodated within approved budgets.

Pollution Probe (PP) INTERROGATORY #3 List 1

Interrogatory

Issue 4.1: Are the proposed 2009 and 2010 Sustaining and Development and Operations capital expenditures appropriate, including such factors as system reliability and asset condition?

3. Will Hydro One's transmission system be capable of accepting up to 300 MW of new bi-directional distributed generation in downtown Toronto by December 31, 2010? If not, please explain why not, and please also state how many MW of new bi-directional distributed generation in downtown Toronto your system will instead be able to accept by December 31, 2010. When answering this interrogatory, please exclude the Portlands Energy Centre from your definition of "new bi-directional distributed generation".

Response

No, we do not expect Hydro One's transmission system to be capable of accepting 300MW of new generation in downtown Toronto by December 2010. Please refer to Interrogatory Exhibit I, Tab 5, Schedule 1.

The feasibility determination and development work to be done during 2009-2010 will provide timing and scope of the uprating work required for Leaside TS, Manby TS and Hearn TS. Please refer to Interrogatory Exhibit I, Tab 5, Schedule 2.

No new generation can be incorporated until such time as the uprating work is complete, other than that specified in Interrogatory I, Tab 5, Schedule 1.

Pollution Probe (PP) INTERROGATORY #4 List 1

Interrogatory

Issue 4.1: Are the proposed 2009 and 2010 Sustaining and Development and Operations capital expenditures appropriate, including such factors as system reliability and asset condition?

4. If Hydro One's transmission system will not be capable of accepting up to 300 MW of new bi-directional distributed generation in downtown Toronto by December 31, 2010, please fully describe the incremental measures that would need to be implemented to achieve this goal. For each measure, please state its cost and the number of additional MW of distributed generation that it would permit in downtown Toronto.

Response

Depending on the outcome of the feasibility determination and development work indicated in response to Interrogatory Exhibit I, Tab 5, Schedule 2, and once the uprating work is complete, it is expected that it will be possible to incorporate 300 MW of Distributed generation in the downtown Toronto. The detailed estimates for this work, and the MWs that will be enabled, will be prepared as part of the development work during 2009 and 2010.

Pollution Probe (PP) INTERROGATORY #5 List 1

Interrogatory

Issue 4.1: Are the proposed 2009 and 2010 Sustaining and Development and Operations capital expenditures appropriate, including such factors as system reliability and asset condition?

5. Please state the quantity of electricity (i.e. in MW) that Hydro One's transmission system can currently accept from Hydro Quebec and deliver to Ontario transmission customers.

Response

Hydro One's summer import capability from Quebec is 1538MW as per IESO Report IESO_REP_0265v12.0 titled, "Ontario Transmission System", dated September 23, 2008.

Pollution Probe (PP) INTERROGATORY #6 List 1

Interrogatory

Issue 4.1: Are the proposed 2009 and 2010 Sustaining and Development and Operations capital expenditures appropriate, including such factors as system reliability and asset condition?

6. Please state the quantity of electricity (i.e. in MW) that Hydro One's transmission system will be able to accept from Hydro Quebec and deliver to Ontario transmission customers in 2010.

Response

By 2010, after the Hydro Quebec 1250 MW Interconnection is placed into service, the import capability from Hydro Quebec will increase by 1250 MW over the current value of 1538 MW for a total capability of 2,788 MW.

Pollution Probe (PP) INTERROGATORY #6 List 1

Interrogatory

Issue 4.1: Are the proposed 2009 and 2010 Sustaining and Development and Operations capital expenditures appropriate, including such factors as system reliability and asset condition?

7. Please describe the additional measures that Hydro One would have to take in order to accept up to an additional 5,000 MW of electricity from Hydro Quebec and to deliver that additional electricity to Ontario transmission customers. Please provide your best estimates of the costs for each of these measures.

Response

The delivery of an additional 5,000 MW from Hydro Quebec would require new infrastructure. One option would be the construction of two new 500 kV double circuit transmission lines from the Ontario Quebec border, probably near Montreal, to the greater Toronto area in the vicinity of either Parkway TS or Claireville TS, a distance of approximately 450 km. Using the cost of the 500 kV Bruce x Milton double line as a rough proxy, two 450 km double circuit lines along with associated station equipment would be about $3B, assuming the necessary approvals could be obtained.

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

Interrogatory

Reference: Exhibit A/Tab 3/Schedule 1/page 2

Issue Number: 2 & 3 & 4 (per PO #2, page 2)

a) Please provide a copy of the 2009-2013 Business Plan referenced on lines 17-21.

Response

Please see response to Exhibit I, Tab 4, Schedule 2.

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

Interrogatory

Reference: Exhibit A/Tab 4/Schedule 1/page 2

Issue: 2 & 3 & 4 (per PO #2, page 2)

a) The Application makes reference to 5-year performance targets. What is the 5-year period associated with these targets?

b) Please provide the 2003-2007 results for each of the performance measures set out on page 2 (if not provided in Exhibit A/Tab 15/Schedule 1).

c) Please describe the Environment Index referenced in Table 1, including:
- How the index is defined.
- How the index is calculated.
- The projected result for 2008.

d) Please describe the Productivity Index referenced in Table 1, including:
- How the index is defined.
- How the index is calculated.
- The projected result for 2008.
- What "95% of Target Achieved" represents.

e) What are the Utility Comparables that Hydro One proposes to use in establishing its 5-year reliability targets?

f) Why is the number of smart meters installed an appropriate performance measure for Hydro One Networks' Transmission Business.

Response

a) The 5-year period is 2009-2013.

b) 2003-2007 results for each of the performance measures set out on page 2 of Exhibit A/Tab 4/Schedule 1 not already provided in Exhibit A/Tab 15/Schedule 1 is summarized in the following table.

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

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

* Tx Reliability for multi- circuit supplied delivery points

c) For the Environmental index, Environmental Initiatives are monitored by a set of Enabling Initiatives; Fleet, Sites and Facilities, with Measures: Reduction of Emissions, Site Remediation and Energy Efficiency. Each of these measures has a set of milestones to be completed

The Environmental Index is calculated by the completion of the Environmental Initiatives milestones as a percentage of the planned. The individual percentages are aggregated to give an overall Year-End Projection

The projected results for 2008 show an overall Year-End Projection of 96%.

d) For the Productivity index, each major Line of Business has a set of measures with quantified planned accomplishments.

For each of these accomplishments a year–end projection was developed, a ratio derived and plotted as a percentage of Plan to generate Productivity Indicators. These Productivity Indicators are compiled to give a LoB index. These indices are then aggregated to give a Corporate Productivity Index

The Corporate Productivity Index for 2008 is projected to be 105%

In developing a Productivity Index the fundamental objective is for all of the individual indicators to meet their targets resulting in meeting the overall Index target. However because of the newness of the indicators and lack of historical data it was expected that one or more of the individual indicators would not meet its target by a significant margin. Hence the use of a 95% target for the overall Productivity Index.

e) The comparable utilities include other large transmission companies in Canada that participate in reliability benchmarking programs such as Hydro Quebec (TransEnergie), BCTC, Altalink, ATCO Electric, Manitoba Hydro.

f) The strategic objective of focusing on continuous innovation to ensure a modern, flexible and smart electricity grid is an objective that applies for both transmission and distribution. To this point, Hydro One has developed a corporate Performance Measure and 5 Year Target only for distribution for smart meter installations.

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

Interrogatory

Reference: Exhibit A/Tab 4/Schedule 1/page 4

Issue: 2 & 3 & 4 (per PO #2, page 2)

a) Please provide tables similar to Table 2 but for the years 2008, 2009 and 2010 based on the current Application.

Response

a) The table below provides the increase in assets over the requested years based on the forecasted Capital work outlined in Exhibit D1-3-3.

Hydro One Transmission System Assets at end of				
	2007	2008	2009	2010
Fixed Assets (NBV Year end)	$6.5B	$6.7B	$7.3B	$7.9B
Operating Centres	2	2	2	2
Transmission System Voltages (kV)	500, 345, 230, 225, 69			
Overhead Transmission Lines (circuit km)	28,314	28,321	28,402	28,487
Underground Transmission Cables (cct km)	275	280	280	280
Transmission Stations	279	279	280	282
Breakers	4,434	4,486	4,534	4,623
Step-down power transformers	591	595	597	601
Auto-transformers	150	150	151	151
Other transformers	688	688	688	688

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

Interrogatory

Reference: i) Exhibit A/Tab 9/Schedule 2/page 5
ii) EB-2006-0501 - Exhibit A/Tab 8/ Schedule 2/ page 5

Issue Number: 3.2

a) Please explain the more than 20% increase in 2008 General Counsel and Secretary Services costs charged to affiliates between the 2007-2008 Application and the current Application.

b) With respect to Financial Services, the increase in 2008 costs charged to affiliates is less than 2% as between the two Applications. However, there is a significant reduction in the amount assigned to Hydro One Inc. and a material increase in the amount assigned to Remotes. Please explain the reasons for this shift.

c) Please explain the more than 10% increase in 2008 Corporate Services costs charged to affiliates between the 2007-2008 Application and the current Application.

d) Please explain the more than 13% increase in 2008 Other Services costs charged to affiliates between the 2007-2008 Application and the current Application.

e) Please explain the almost quadruple increase in 2008 Utility Operation Services charged to Remotes between the 2007-2008 Application and the current Application.

Response

a) General Counsel and Secretary expenses charged to affiliates did not increase by more than 20% between the 2007-2008 Application and the current Application. Please refer to the schedule below which shows that the percentage increase to affiliates ranges from 7% to 9% with the total increase being less than $40k.

	Hydro One Inc.	Remotes	Telecom	Brampton	Total
Current Application	75	220	75	150	520
06 - '07 Application	70	202	70	140	482
% Change	7.1%	8.9%	7.1%	7.1%	7.9%

b) The change in the allocation of Financial Services charges reflects the assignment of Financial Strategy costs to Brampton, Telecom and Remotes to more accurately reflect the services that they provide.

c) The increase of more than 10% in Corporate Services ($25 thousand) is driven primarily by higher Supply Chain Management and Human Resource costs embedded within Corporate Services.

d) The Inergi contract costs increased between the 2007 – 2008 application and the current application mainly due to increased COLA and increased scope and volume changes in all sustainment contracts.

e) The 2007-2008 Application did not reflect all of the utility operation activities being charged to Remotes by Hydro One Networks – the $0.3M was based on an estimate that did not reflect cost for fleet services. The full cost of services charged was $0.7M. These charges are reflected in the Remotes Financial Statements.

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

Interrogatory

Reference: i) Exhibit A/Tab 9/Schedule 2/page 7
ii) EB-2006-0501 - Exhibit A/Tab 8/ Schedule 2/ page 7

Issue Number: 3.2

a) Please explain the more than 40% increase in 2008 charges to Hydro One Networks from Telecommunication Services as between the 2007-2008 Application and the current Application.

Response

a) The cost of Telecommunication Services has increased primarily due to the inclusion of a labour and pension adjustment which was previously not included in Telecom charges. Also contributing to the increase is a higher level of services related to alarm based services, network management and in systems analysis services.

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

Interrogatory

Reference: i) Exhibit A/Tab 9/Schedule 2/Appendix A, page 8

Issue Number: 3.2

a) Please describe the basis on which the charges to Hydro One Networks were established.

Response

a) The charges to Hydro One Networks are based on the Rudden common cost allocation methodology and are established and reviewed as part of the annual business planning process which includes a review by the Executive Committee and subsequent approval by the Board of Directors.

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

Interrogatory

Reference: i) Exhibit A/Tab 9/Schedule 2/Appendix B, page 8 and Appendix C, page 1

Issue Number: 3.2

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

Response

a) The charges for the services are based on the Rudden common cost allocation methodology and are established and reviewed as part of the annual business planning process which includes a review by the Executive Committee and subsequent approval by the Board of Directors.

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

Interrogatory

Reference: i) Exhibit A/Tab 9/Schedule 2/pages 5-6
ii) EB-2007-0501 - Exhibit A/Tab 8/ Schedule 3/ pages 5-6

Issue Number: 3.2

a) Please explain why the 2008 General Counsel and Secretary Services costs payable by affiliates increase by roughly 14% as between the two Applications while the costs for Financial Services, Corporate Services, Telecommunications Services and Other Services are the same.

Response

a) If the reference in (ii) is supposed to be EB-2007-0681 – Exhibit A, Tab 8, Schedule 3 there is no change in 2008 General Counsel and Secretary Services costs between the two Applications.

If the reference in (ii) is supposed to be EB-2006-0501 please see response in Exhibit I, Tab 6, Schedule 4 part (a).

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

Interrogatory

Reference: i) Exhibit A/Tab 9/Schedule 2/Appendix D, Schedules A & B
ii) EB-2006-0501 – Exhibit A/Tab 8/Schedule 2, Appendix D, Schedules A & B

Issue Number: 3.2

a) Please describe the increase in services provided by Hydro One Telecom Inc. that leads to an increase in costs payable by Hydro One Networks for Power System - Operation of Telecommunications Services of 45% between 2006 and 2008. (See Schedules A of the two references)

b) Please describe the increase in services provided by Hydro One Telecom Inc. that leads to an increase in costs payable by Hydro One Networks for Business System - Operation of Telecommunications Services of 37% between 2006 and 2008. (See Schedules B of the two references)

Response

a) Power System - Operation of Telecommunications Services (PSTS) base service costs increased from 2006 to 2007 to accommodate higher levels of service for alarm based services, network management and systems analysis. In 2007, the costs were increased for a one-time pension adjustment. In addition, there was an annual 4% increase in both 2007 and 2008, in accordance with the terms of the contract.

b) Business System - Operation of Telecommunications Services (BSTS) service costs increased from 2006 to 2007 to accommodate the higher levels of service referenced in part (a) above. A one-pension adjustment was also made in 2007 as well as a 4% increase in both 2007 and 2008.

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

Interrogatory

Reference: Exhibit A/Tab 9/Schedule 2/Appendices A-H

Issue Number: 3.2

Preamble: The Service Agreements provided in the Application appear to all pre-date the May 16, 2008 OEB revisions to the Affiliate Relationships Code.

a) Has Hydro One Networks reviewed its Service Agreements with affiliates to ensure they are consistent with the May 16, 2008 revised Code?

b) If not, when will such a review occur?

c) If yes, are there any changes required to the agreements that will impact on 2008 and future years' costs and what are they?

Response

a) Yes, Hydro One has reviewed their Affiliate Service Agreements to ensure that they are consistent with the revised Code

b) Not Applicable

c) No changes are required to the agreements that impact on 2008 and future years' costs

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

Interrogatory

Reference: i) Exhibit A/Tab 10 Schedule 1
ii) Exhibit A/Tab 3/Schedule 1, page 6

Issue Number: 3.6

a) Reference (ii) attributes the increase in revenue requirement for 2009 to increased carrying costs associated with asset growth. However, in reference (i) in-service fixed assets grow by 10% between 2004 and 2007 but the level of depreciation charges stays constant at $207 M. Please explain why historically depreciation charges have not increased as assets in-service increase and why this changes for 2009.

Response

Total asset growth for the four year period of 2004 to 2007 has been accompanied by stable depreciation expense levels. This is because increased investments do not necessarily result in related increases in total depreciation expense. There are a number of factors that go into the depreciation calculation that have the potential to combine to impact overall depreciation expense levels. These include depreciation rate changes, service lives of newly added assets, the mix of asset types (e.g. major versus minor) and annual levels of depreciation expense capitalized. The depreciation method can also affect total depreciation expense. For example, amortization accounting was introduced for some minor asset categories effective January 1, 2007. As a result of these factors, during the 2004 to 2007 period, an overall increase in transmission major asset depreciation, which was primarily a result of changes in asset mix, was offset by a reduction in minor fixed asset depreciation resulting from varying annual additions of transport and work equipment and power equipment purchases.

In 2008 and 2009, the Cornerstone project is being put into service. These information technology assets have shorter useful lives than the average, thus they have a higher depreciation rate. This serves to magnify the impact on depreciation expense of increasing the asset base. As noted in Exhibit C1, Tab 6, Schedule 1, Section 2.0 Depreciation Expense, depreciation expense increased $3.1 M in 2009 as a result of the Foster's Technical Update.

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

Interrogatory

Reference: i) Exhibit A/Tab 13/Schedule 1, page 5
ii) OEB Staff IR #9

Issue Number: 3.2

a) Along with the annual costs, as requested in reference (ii), please indicate:
   - What are the costs in each year that are allocated to Hydro One Networks' Transmission Business?
   - How is the portion allocated to the Transmission Business determined?
   - Why is it not appropriate to defer such conversion costs until 2011 and beyond?

Response

a)
- IFRS costs are not specifically allocated to Transmission, rather these costs are part of the Finance function amounts found in Table 3 of Exhibit C1, Tab 2, Schedule 6, page 5. The proportion of Finance costs allocated to Transmission is 50.3%.

- Since the IFRS amounts are part of the Finance function, the allocation of the Finance costs and the IFRS costs contained within, are allocated according to the Rudden cost allocation methodology.

- Under Canadian GAAP, these expenditures are appropriately accounted for as period costs. Hydro One has not proposed deferral and amortization of the resultant costs to future years as this would not result in a more equitable distribution of costs to customers.

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

Interrogatory

Reference: i) Exhibit A/Tab 14/Schedule 1/Appendix A
ii) Exhibit A/Tab 14/Schedule 2, pages 1-6

Issue Number: 2 & 3 & 4 (per PO #2, page 2)

a) Given the recent changes in economic conditions worldwide, does Hydro One Networks consider it reasonable to rely on a forecast economic outlook that is roughly a year old? If yes, please explain why.

b) With respect to page 1, is Hydro One Networks aware of any more recent projections of inflation and cost escalation for 2009 and 2010? If yes, please provide.

c) With respect to page 1, please provide an update of the interest rate forecast for 2009 and 2010 provided at lines 14-15 based on the October 2008 edition of Consensus Forecasts.

d) With respect to reference (ii), please update the 2008 forecast interest rates applicable to HOI as used in the Application based on the most recent forecasts/actual results to-date.

e) With respect to reference (ii) – page 3, please update the exchange rate forecast based on the October 2008 edition of Consensus Forecasts.

f) What is the sensitivity of Hydro One Networks' proposed 2009 and 2010 revenue requirements to:
- A 100 basis point change in forecast interest rates. (Note: Please exclude any impact on ROE or short-term interest rates used in determining the cost of capital)
- A 10 cent change in the forecast exchange rate (CDN$ per US$)?

g) With respect to page 2 of reference (i), what are the labour escalation assumptions used for the 2008 bridge year?

Response

a) Please see response to Exhibit I, Tab 1, Schedule 10.

b) Projections of inflation and cost escalation are updated on a monthly basis by the Government of Canada and by groups such as Global Insight. Please see Exhibit I, Tab 1, Schedules 3 and 4 for the recent projections.

c) The following is an update of the interest rate forecast for 2009 and 2010 provided in the table at lines 14-15 of page 1 of Appendix A based on the October 2008 edition of *Consensus Forecasts*.

	2009	**2010**
HO1 5-Year Bond Rate (%)	4.82	5.67
HO1 10-Year Bond Rate (%)	6.03	6.88
HO1 30-Year Bond Rate (%)	6.72	7.57
90-Day Banker's Acceptance Rate (%)	3.59	
Interest Capitalized Tx (%)	6.43	7.28
Interest Capitalized Dx (%)	6.43	7.28
Interest Capitalized Common (%)	6.43	7.28

Note - The October long term *Consensus Forecast* does not contain a forecast of Canadian short term interest rates (i.e. T-bill) for 2010. Hence, a forecast of the 90 day Banker's Acceptance rate for 2010 based on *Consensus Forecasts* is not available yet.

d) Please refer to response to part (a) of Exhibit I, Tab 2, Schedule 20 for the actual interest rates on debt forecast to be issued in 2008.

e) The following is the exchange rate forecast based on the October edition of *Consensus Forecasts* (page 27).

	2008	**2009**	**2010**
Exchange Rate (CDN$ per US$)	1.154	1.107	1.144

Note – The 2008 rate is based on October 13 spot rate. The 2009 rate is based on the average Jan 09 forecast (1.101) and Oct 09 forecast (1.113). The 2010 rate is based of the forecast for the end of Oct 2010.

f) i) If the forecasted interest rates (rates on third party debt issuances in 2009 and 2010 and deemed long-term debt rates) were lower by 100 basis points, revenue requirement in 2009 would be lower by $7.5M and 2010 revenue requirement would be lower by $12.9M.

ii) As discussed on lines 13 to 15 of page 3 of Exhibit A, Tab 14 Schedule 2, the exchange rate forecast is not directly used to forecast costs or other variables, it is an important variable affecting the performance of the Canadian and Ontario economies.

g) Escalations used in the 2008 bridge year:

Society Staff

3% economic increases effective April 1, 2008

PWU staff

3% economic increases effective April 1, 2008

Step progressions - past experience (i.e. 2005) indicates that 9.9% of PWU receive progressions annually and that progressions result in a salary increase of 4.35% (note that trades progressions are higher than weekly salaried, and due to apprentice hiring over the past few years, the proportion of trades progressions has increased).

MCP staff

4% annual increase per year in base pay

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

Interrogatory

Reference: i) Exhibit A/Tab 14/Schedule 3, pages 6-7

Issue Number: 2 & 3 & 4 (per PO #2, page 2)

a) Reference is made to a "consensus forecast" (page 6, line 7 and page 7, line 6). Is this the April 2008 Edition of Consensus Forecasts? If not, what is it?

b) Please update the forecast of Ontario GDP, Housing, Commercial Floor Space and Industrial Production for the most recently available forecast(s).

Response

(a) The "consensus forecast" does not refer to the Consensus Forecasts published by Consensus Economics Inc. from London, England because it only has a forecast for up to 2 years for Canada. The "consensus forecast" referred to in Exhibit A, Tab 14, Schedule 3 was prepared by Hydro One using available information from 4 forecasting firms (Global Insight, Conference Board of Canada, Centre for Spatial Economics, University of Toronto) and 5 major chartered banks (CIBC, BMO, Royal, Scotia and TD).

(b) The following provides an update of the economic data using available information as of December 15, 2008.

Ontario GDP is expected to decline by 0.1% in 2008 and 0.2% in 2009, following by a recovery of 2.9% growth in 2010.

Housing starts are expected reach about 76,000 units in 2008, followed by about 65,000 units for both 2009 and 2010.

Commercial floor space forecast is expected to be on track for 2008 as forecast. No new forecast is available for 2009 and 2010.

Industrial production is expected to decline by about 7% in 2008 and 3% in 2009, followed by a recovery of 5% growth in 2010.

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

Interrogatory

Reference: i) Exhibit A/Tab 14/Schedule 3, pages 8-10
ii) Exhibit A/Tab 14/Schedule 3/Attachment C
iii) OEB Decision EB-2006-0501, pages 91-92

Issue Number: 2.1

a) With respect to Attachment C (Section 2.0 and Appendix A), please confirm that Demand Response programs contributed 590 MW towards the 1390 MW savings set out in Table 2? If Hydro One Networks does not agree, please explain why.

b) Based on the Board's comments in reference (iii), please explain why the 350 MW number the Board set out in its decision wasn't updated to reflect the actual 590 MW of demand response.

c) With respect to Attachment C (Section 4.0), what is Hydro One Networks' understanding as what is included in Demand Management Programs that contributes to the MW reductions shown in Table 3?

d) With respect to Attachment C (Section 4.0) and the Board's EB-2006-0501 Decision, is it reasonable to assume that under normal weather conditions, loads will be reduced by the total MWs attributed to Demand Management programs? Please fully explain the response.

e) Are the embedded generation by-pass MWs (reference (i), page 10) for 2009 and 2010 based entirely on known commitments for embedded generation or do they include assumptions regarding future commitments that will be made and come into service in 2009 and/or 2010? If the later, please explain why this reasonable given the lead times required for new generation.

Response

(a) Of the 1,390 MW of peak savings reported by the OPA in June 2008, 590 MW are attributed by the OPA to demand response programs. It should be noted that, according to the OPA, these reported results will be subject to detailed evaluation, measurement and verification in the future.

(b) As documented in Section 3.7, page 8 of Exhibit A, Tab 14, Schedule 3, Hydro One has followed the Board's directive to include 1,000 MW of peak load reduction for

2007. Hydro One has not received any new directive from the Board to make further revisions.

(c) Hydro One uses the CDM forecast provided by the OPA consistent with the IPSP submitted to the Board in August 2008. Hydro One does not have any further details from the OPA with respect to its plan for demand management programs as shown in Table 3 in Section 4 of Attachment C.

(d) Hydro One agrees this is a reasonable assumption because under weather normal conditions there will be peak demand that will be reduced by demand management programs.

(e) The embedded generation bypass forecast was based on a review of over 700 generation applications submitted to Hydro One and renewable generation contract applications reviewed by the OPA. The bypass forecast takes into consideration the lead time required for the generation projects. As shown in the table below, the embedded generation bypass forecasts are largely based on known commitments.

	Cumulative Bypass Applicable in 2009 (MW)	Cumulative Bypass Applicable in 2010 (MW)
Committed Projects	200	200
RESOP	80*	110*
CESOP	0	40
Total MW Assumed in Load Forecast	280	350

**Based on renewable generation applications received by Hydro One and OPA at various stages of the commitment process.*

The total bypass forecast assumed for 2009 and 2010 is reasonable because the bulk of the assumed bypass is based on committed projects and the RESOP amount is based on assuming only about 10% of the applications received will go ahead. The bypass forecast does not factor in the government direction for the OPA to review the IPSP with a view to increasing the amount and diversity of renewable energy sources.

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

Interrogatory

Reference: i) Exhibit A/Tab 14/Schedule 3, pages 8-10
ii) Exhibit A/Tab 14/Schedule 3/Attachment B

Issue Number: 2.1

a) With respect to Attachment B (Section 4.3 and Table 5), please provide the derivation of the 370 MW set out in reference (ii), Section 4.3 using the formulae described on lines 13-16,

b) Similarly, please provide the derivation of the 400 MW shown in Table 5 for the summer of 2009.

c) Please reconcile the CDM and Embedded Generation values used in response to parts (a) and (b) with the CDM and embedded generation values Hydro One has use in its Load Forecast per reference (i).

Response

a) There is no Table 5 in Attachment B. Hydro One assumes the reference is to Table 1. The 370 MW is an estimate of the difference in total CDM peak savings that the IESO and Hydro One would deduct from their demand forecasts. The formula illustrates how the IESO's total CDM savings differs from Hydro One's total CDM savings. Hydro One does not have the details to do the calculation using the formula described on lines 13-26. (This response was reviewed by the IESO)

b) There is no Table 5 in Attachment B. Hydro One assumes the reference is to Table 1. The 400 MW for 2009 is the difference in total CDM peak savings that the IESO and Hydro One would deduct from their demand forecasts. Hydro One does not have the details to do the calculation using the formula described on lines 13-26. (This response was reviewed by the IESO)

c) The following tables (Tables 1 and 2) provide more detailed CDM and embedded generation information used by Hydro One supporting the analysis for reference (i) and (ii). The numbers used by Hydro One in reference (i) pertain to the summer peak for the calendar year (e.g. CDM impact for 2009 is 1,620 MW), while the numbers used in reference (ii) pertain to various periods for comparison with the IESO (e.g. 18-month period from Apr 08 to Sep 09).

Table 1: Hydro One's Assumptions for CDM & Embedded Generation (MWs)

Forecast Period	CDM (inclusive of Demand Response) (1)	Embedded Generation (2)	Total (3) =(1)+(2)
2008:Apr-Dec	1,017	190	1,207
2009:Jan-Sep	1,317	280	1,597
Apr 08 to Sept 09	1,167	235	1,402
Summer 2008	1,251	190	1,441
Winter 2008-09	1,347	280	1,627
Summer 2009	1,620	280	1,900

Note: January is used for winter peak, July for summer peak

Table 2: Hydro One's CDM Assumptions by Month (MW)

Month	2008	2009
Jan	987	1,347
Feb	924	1,198
Mar	857	1,117
Apr	821	1,024
May	827	1,016
Jun	1,223	1,557
Jul	1,251	1,620
Aug	1,234	1,579
Sep	1,154	1,396
Oct	829	1,050
Nov	842	1,081
Dec	970	1,307
Average		
Annual	993	1,274
2008:Apr-Dec	1,017	
2009:Jan-Sep		1,317
18-Month (Apr 08 to Sep 09)		1,167
Summer 2008	1,251	
Winter 2008/2009		1,347
Summer 2009		1,620

Note: January is used for winter peak, July for summer peak

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

Interrogatory

Reference: i) Exhibit A/Tab 14/Schedule 3, page 22
ii) Exhibit A/Tab 3/Schedule 1, page 6

Issue Number: 2.1

Preamble: Reference (ii) suggests that while the overall load forecast is declining, there are areas of the province where loads are increasing.

a) Please provide a breakdown of the 2008-2010 load forecast by region, including for each region:
   - The regional peak demand forecast
   - The regional peak demand forecast consistent with the system peak

   (Note: If possible, please provide the breakdown based on the IESO's regional definitions)

b) Please provide a schedule that provides the information requested in part (a) for 2003 – 2007 on a monthly basis.

c) Please confirm that the forecast of Network Connection charge determinant takes into account the 85% of NCP adjustment where appropriate.

Response

(a) The requested information is provided below.

Peak-Load by Region (MW)

Year	Region	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2008	Central	11,713	11,540	10,776	10,029	9,794	12,702	13,082	12,758	10,769	10,252	11,032	11,304
	East	3,509	3,395	3,258	2,747	2,378	3,083	3,088	3,111	2,681	2,646	3,136	3,442
	Northeast	1,312	1,277	1,229	1,188	999	973	1,074	1,085	971	1,163	1,206	1,345
	Northwest	806	790	692	689	579	616	689	607	555	633	706	742
	Southwest	4,914	4,862	4,409	4,210	4,323	5,379	5,503	5,327	4,519	4,437	4,516	4,714
2009	Central	11,672	11,500	10,736	9,990	9,758	12,660	13,039	12,717	10,734	10,212	10,993	11,266
	East	3,492	3,378	3,242	2,733	2,366	3,068	3,073	3,096	2,668	2,633	3,121	3,425
	Northeast	1,271	1,238	1,191	1,151	967	943	1,041	1,050	941	1,127	1,168	1,303
	Northwest	791	775	679	676	568	605	676	595	545	621	692	728
	Southwest	4,903	4,851	4,399	4,200	4,313	5,367	5,490	5,315	4,509	4,427	4,505	4,703
2010	Central	11,070	11,096	10,176	9,791	9,604	12,427	12,750	12,481	10,548	10,049	10,638	10,700
	East	3,307	3,255	3,068	2,676	2,326	3,006	3,000	3,033	2,616	2,588	3,016	3,247
	Northeast	1,173	1,161	1,097	1,098	925	899	989	1,002	898	1,078	1,099	1,203
	Northwest	738	736	634	652	550	584	651	575	527	602	660	680
	Southwest	4,655	4,686	4,175	4,122	4,250	5,272	5,373	5,221	4,434	4,363	4,365	4,470

Note. All figures are weather-normal on a monthly basis.

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

Year	Region	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2008	Central	12,093	11,811	11,102	10,287	10,000	13,013	13,359	13,090	11,044	10,453	11,419	11,664
	East	3,623	3,474	3,357	2,817	2,428	3,159	3,154	3,192	2,749	2,698	3,246	3,552
	Northeast	1,355	1,307	1,266	1,219	1,020	997	1,097	1,113	996	1,186	1,248	1,388
	Northwest	832	809	713	707	591	632	704	622	569	646	731	766
	Southwest	5,073	4,976	4,543	4,318	4,414	5,510	5,619	5,466	4,634	4,524	4,674	4,864
2009	Central	11,995	11,754	11,044	10,248	10,025	13,003	13,337	13,077	11,057	10,471	11,373	11,576
	East	3,589	3,453	3,335	2,804	2,431	3,151	3,143	3,184	2,748	2,700	3,229	3,519
	Northeast	1,307	1,265	1,225	1,181	994	968	1,064	1,080	969	1,155	1,209	1,339
	Northwest	813	792	699	694	583	621	692	612	561	637	716	748
	Southwest	5,039	4,958	4,525	4,308	4,431	5,512	5,615	5,466	4,644	4,539	4,661	4,832
2010	Central	11,385	11,349	10,474	10,050	9,872	12,770	13,049	12,843	10,871	10,310	11,013	11,000
	East	3,401	3,329	3,158	2,747	2,391	3,089	3,070	3,121	2,697	2,655	3,122	3,339
	Northeast	1,206	1,188	1,129	1,127	951	924	1,012	1,031	925	1,106	1,138	1,237
	Northwest	759	753	652	670	566	600	666	591	543	617	683	699
	Southwest	4,787	4,792	4,297	4,232	4,369	5,418	5,499	5,372	4,570	4,476	4,518	4,596

Note. All figures are weather-normal on a monthly basis.

(b) The requested information is provided below.

Peak-Load by Region (MW)

Year	Region	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2003	Central	11,643	11,523	10,789	9,907	9,844	12,009	12,320	12,035	10,945	10,014	11,055	11,655
	East	3,746	3,664	3,355	2,800	2,564	3,015	3,074	3,071	2,948	2,761	3,197	3,600
	Northeast	1,445	1,472	1,348	1,290	1,163	870	842	883	1,106	1,137	1,332	1,420
	Northwest	1,083	1,109	991	968	960	860	910	882	948	869	962	1,025
	Southwest	4,967	4,924	4,591	4,306	4,170	4,992	5,362	5,362	4,775	4,379	4,929	5,099
2004	Central	11,699	11,800	11,120	10,122	10,244	12,236	12,332	12,161	11,221	10,372	11,350	11,855
	East	3,787	3,609	3,168	2,927	2,459	2,849	2,899	2,900	2,662	2,748	3,201	3,789
	Northeast	1,411	1,522	1,348	1,226	1,097	1,041	955	1,067	1,120	1,250	1,384	1,479
	Northwest	956	982	953	850	885	856	831	847	841	884	991	957
	Southwest	4,906	5,080	4,814	4,271	4,273	5,136	5,305	5,268	4,889	4,377	4,909	4,987
2005	Central	12,117	12,018	11,193	10,294	10,115	12,142	12,660	12,448	11,460	10,522	11,427	11,960
	East	3,710	3,513	3,264	2,845	2,537	2,980	3,109	3,003	2,830	2,683	3,181	3,575
	Northeast	1,377	1,461	1,346	1,237	1,165	1,010	1,052	1,113	1,078	1,045	1,221	1,351
	Northwest	991	1,016	891	913	873	814	763	778	771	830	913	940
	Southwest	5,020	5,077	4,661	4,328	4,124	5,194	5,138	5,277	4,808	4,534	4,715	5,049
2006	Central	12,020	11,916	11,302	10,242	10,539	12,432	12,498	12,298	10,917	10,290	11,091	11,685
	East	3,535	3,460	3,213	2,739	2,506	2,972	3,101	3,048	2,743	2,817	3,095	3,361
	Northeast	1,396	1,391	1,299	1,227	834	1,147	1,025	1,000	1,217	1,189	1,251	1,275
	Northwest	929	911	809	781	572	736	685	637	740	802	769	834
	Southwest	4,948	4,885	4,698	4,313	4,359	5,002	5,300	5,171	4,493	4,301	4,695	5,145
2007	Central	11,765	11,630	10,489	10,079	9,927	11,908	12,301	12,208	11,158	10,369	11,642	11,931
	East	3,529	3,426	3,175	2,763	2,414	2,895	2,908	2,982	2,786	2,673	3,314	3,637
	Northeast	1,355	1,323	1,230	1,228	1,041	939	1,039	1,068	1,038	1,211	1,309	1,459
	Northwest	822	809	685	703	596	587	659	590	586	650	757	795
	Southwest	4,929	4,893	4,286	4,223	4,376	5,037	5,168	5,093	4,676	4,485	4,759	4,969

Note. All figures are weather-corrected on a monthly basis.

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

Year	Region	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2003	Central	12,013	11,879	11,165	10,157	10,124	12,351	12,564	12,365	11,247	10,486	11,525	12,079
	East	3,865	3,777	3,471	2,871	2,637	3,101	3,135	3,155	3,030	2,891	3,333	3,731
	Northeast	1,491	1,517	1,395	1,322	1,196	895	859	907	1,136	1,191	1,388	1,472
	Northwest	1,118	1,143	1,026	992	987	885	929	906	974	910	1,003	1,062
	Southwest	5,125	5,076	4,751	4,415	4,288	5,134	5,468	5,509	4,907	4,585	5,139	5,285
2004	Central	12,170	12,092	11,496	10,445	10,468	12,535	12,809	12,579	11,649	10,672	11,863	12,244
	East	3,940	3,698	3,275	3,021	2,513	2,919	3,011	2,999	2,764	2,828	3,346	3,913
	Northeast	1,468	1,559	1,394	1,265	1,121	1,067	992	1,104	1,163	1,286	1,446	1,528
	Northwest	994	1,006	985	878	904	877	863	877	873	909	1,036	988
	Southwest	5,103	5,205	4,977	4,407	4,367	5,261	5,511	5,449	5,076	4,503	5,131	5,151
2005	Central	12,462	12,330	11,629	10,605	10,434	12,587	13,080	12,875	11,898	10,792	11,864	12,356
	East	3,816	3,604	3,391	2,931	2,617	3,089	3,212	3,106	2,938	2,752	3,302	3,694
	Northeast	1,416	1,499	1,399	1,274	1,202	1,047	1,087	1,151	1,119	1,072	1,268	1,395
	Northwest	1,019	1,043	926	940	901	844	788	805	801	851	948	971
	Southwest	5,163	5,209	4,842	4,459	4,254	5,384	5,309	5,458	4,992	4,651	4,895	5,216
2006	Central	12,584	12,262	11,666	10,595	10,842	12,731	12,780	12,728	11,134	10,511	11,539	12,135
	East	3,701	3,560	3,316	2,833	2,578	3,044	3,171	3,154	2,798	2,878	3,220	3,491
	Northeast	1,461	1,432	1,340	1,269	858	1,175	1,048	1,035	1,241	1,215	1,302	1,324
	Northwest	973	938	835	808	589	754	701	659	755	820	800	866
	Southwest	5,180	5,027	4,849	4,462	4,484	5,123	5,420	5,351	4,583	4,393	4,885	5,344
2007	Central	12,200	11,964	10,844	10,368	10,091	12,273	12,465	12,465	11,323	10,565	12,005	12,296
	East	3,660	3,524	3,282	2,842	2,453	2,984	2,947	3,045	2,827	2,723	3,417	3,748
	Northeast	1,405	1,361	1,271	1,263	1,058	968	1,053	1,090	1,053	1,234	1,349	1,504
	Northwest	853	832	708	723	606	605	667	602	595	662	780	820
	Southwest	5,111	5,034	4,430	4,344	4,448	5,192	5,237	5,200	4,745	4,570	4,907	5,121

Note. All figures are weather-corrected on a monthly basis.

c) The network connection charge determinant forecast takes into account the 85% of NCP adjustment where appropriate.

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

Interrogatory

Reference: EB-2006-0501, Exhibit J/Tab 5

Issue Number: 2.1 and 7.1

a) Please update the response to VECC IR#121 such that parts (i) and (ii) cover 2008-2010 and part (iii) included 2007 data.

Response

Please see the following table for response to a(i).

Ontario Demand and Charge Determinanats Before Deducting Impacts of CDM and Embedded Generation (in MW)

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Average
2008 (Note 1)													
Ontario Demand	24,154	23,491	22,027	20,359	19,469	24,723	25,373	24,906	21,337	20,525	22,350	23,392	22,676
Network Connection	23,844	23,282	21,251	19,823	18,898	23,719	24,576	24,122	20,949	20,278	21,724	22,742	22,101
Line Connection	22,599	21,863	20,105	19,109	17,854	22,729	23,436	22,720	20,444	19,785	20,614	21,247	21,042
Transformation Connection	19,733	19,137	17,466	16,357	15,491	19,504	20,383	19,758	17,455	16,859	17,754	18,411	18,192
2009													
Ontario Demand	24,369	23,700	22,223	20,540	19,759	25,092	25,751	25,277	21,655	20,831	22,549	23,600	22,946
Network Connection	23,997	23,432	21,452	20,012	19,192	24,084	24,953	24,493	21,273	20,592	21,929	22,956	22,364
Line Connection	22,811	22,067	20,282	19,278	18,120	23,064	23,781	23,055	20,747	20,078	20,795	21,433	21,293
Transformation Connection	19,914	19,312	17,620	16,503	15,722	19,793	20,683	20,050	17,714	17,110	17,911	18,573	18,409
2010													
Ontario Demand	24,510	23,837	22,351	20,658	19,992	25,387	26,054	25,575	21,910	21,076	22,679	23,736	23,147
Network Connection	24,135	23,567	21,575	20,127	19,417	24,367	25,247	24,781	21,524	20,834	22,056	23,089	22,560
Line Connection	22,942	22,194	20,399	19,389	18,333	23,335	24,060	23,326	20,991	20,314	20,915	21,556	21,480
Transformation Connection	20,029	19,424	17,722	16,598	15,907	20,025	20,927	20,286	17,923	17,312	18,015	18,680	18,571

Note 1: 2008 values are forecast using information up to April 2008 to prepare proxy charge determinant values

Please see the following table for response to a(ii).

Ontario Demand and Charge Determinanats After Deducting Impacts of CDM and Embedded Generation (in MW)

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Average
2008 (Note 1)													
Ontario Demand	22,977	22,377	20,980	19,348	18,452	23,310	23,932	23,483	19,993	19,507	21,318	22,232	21,492
Network Connection	22,691	22,191	20,226	18,834	17,902	22,337	23,167	22,730	19,634	19,280	20,714	21,607	20,943
Line Connection	21,673	20,995	19,300	18,338	17,077	21,584	22,265	21,565	19,363	19,006	19,823	20,337	20,111
Transformation Connection	18,931	18,385	16,768	15,688	14,817	18,513	19,369	18,758	16,519	16,185	17,069	17,623	17,386
2009													
Ontario Demand	22,742	22,222	20,826	19,235	18,463	23,254	23,851	23,418	19,979	19,501	21,188	22,013	21,391
Network Connection	22,404	21,984	20,083	18,733	17,922	22,286	23,095	22,674	19,633	19,289	20,596	21,403	20,842
Line Connection	21,550	20,946	19,236	18,318	17,168	21,608	22,268	21,579	19,441	19,094	19,782	20,210	20,100
Transformation Connection	18,823	18,341	16,714	15,671	14,897	18,533	19,374	18,773	16,584	16,258	17,034	17,515	17,376
2010													
Ontario Demand	21,538	21,410	19,710	18,825	18,149	22,802	23,297	22,957	19,606	19,164	20,474	20,871	20,734
Network Connection	21,230	21,194	18,993	18,332	17,612	21,839	22,552	22,221	19,270	18,962	19,898	20,287	20,199
Line Connection	20,499	20,258	18,263	18,003	16,938	21,250	21,817	21,211	19,168	18,855	19,183	19,212	19,555
Transformation Connection	17,915	17,748	15,874	15,398	14,699	18,222	18,986	18,456	16,345	16,049	16,516	16,652	16,905

Note 1: 2008 values are forecast using information up to April 2008 to prepare proxy charge determinant values

Please see the following table for response to a(iii).

Actual Ontario Demand and Hydro One Charge Determinants (in MW)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2002												
Ontario Demand					20,068	23,578	25,226	25,414	25,062	21,216	21,862	23,334
Network Connection					19,991	23,336	25,295	24,803	24,547	20,880	21,376	22,730
Line Connection					19,182	22,104	24,081	23,462	23,081	20,149	20,139	21,361
Transformation Connection					16,397	19,162	21,030	20,415	19,993	17,288	17,264	18,591
2003												
Ontario Demand	24,158	23,469	23,117	21,010	18,741	24,753	23,175	23,891	20,700	20,408	21,584	22,798
Network Connection	23,620	22,903	22,694	20,813	18,700	24,427	23,151	23,758	19,668	20,528	20,950	21,960
Line Connection	21,925	21,550	21,125	19,714	18,196	22,958	22,005	22,178	19,401	18,721	19,930	20,826
Transformation Connection	19,156	18,838	18,351	16,813	15,273	19,921	19,140	19,328	16,487	15,976	17,153	18,231
2004												
Ontario Demand	24,937	22,608	21,634	19,911	20,327	23,163	23,976	23,159	21,911	19,829	22,066	24,979
Network Connection	24,166	21,860	20,990	19,448	20,034	22,752	22,304	22,687	21,435	19,454	21,055	24,299
Line Connection	22,297	20,643	20,014	18,770	19,241	21,611	20,890	21,361	20,388	18,868	19,963	22,337
Transformation Connection	19,795	18,091	17,211	16,110	16,344	18,573	18,060	18,481	17,472	15,992	17,068	19,570
2005												
Ontario Demand	24,362	22,322	22,724	19,343	19,007	26,157	26,160	25,816	23,914	20,752	22,564	23,766
Network Connection	23,713	21,684	22,075	18,899	18,739	25,520	25,447	25,023	23,305	20,611	22,072	23,000
Line Connection	22,237	20,712	20,581	18,424	18,328	24,163	24,123	23,507	21,807	19,937	20,672	21,651
Transformation Connection	19,351	17,846	17,818	15,466	15,314	20,806	20,945	20,311	18,747	17,008	17,800	18,854
2006												
Ontario Demand	23,052	22,321	21,772	19,582	24,857	23,349	26,092	27,005	19,976	19,590	21,267	22,941
Network Connection	22,083	21,562	21,028	19,073	24,272	22,491	25,405	26,292	19,692	19,372	20,726	22,343
Line Connection	20,821	20,727	19,900	18,415	22,909	21,519	24,198	24,732	19,214	18,919	19,666	20,870
Transformation Connection	18,017	17,964	17,170	15,649	19,748	18,337	20,911	21,371	16,285	15,999	16,822	18,098
2007												
Ontario Demand	23,537	23,935	22,969	20,016	21,490	25,737	24,561	25,584	24,046	19,233	21,814	22,935
Network Connection	22,766	23,278	22,406	19,614	21,020	24,926	23,864	24,951	23,277	18,909	21,539	22,220
Line Connection	21,370	21,872	21,126	19,181	20,358	23,572	23,126	23,620	22,239	19,197	20,466	21,190
Transformation Connection	18,550	19,078	18,291	16,205	17,203	20,433	20,040	20,638	19,253	16,464	17,720	18,567

Note 1: Charge determinant values are proxy numbers calculated based on actual load

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

Interrogatory

Reference: i) Exhibit A/Tab 15/Schedule 1, pages 3-15
ii) Exhibit A/Tab 4/Schedule 1, page 2

Issue Number: 2 & 3 & 4 (per PO #2, page 2)

a) With respect to reference (i) and Safety Performance, is there a difference between the "Lost Time Injuries" performance measure used in reference (ii) and the "Serious Lost Time Injuries" measure used in reference (ii)?

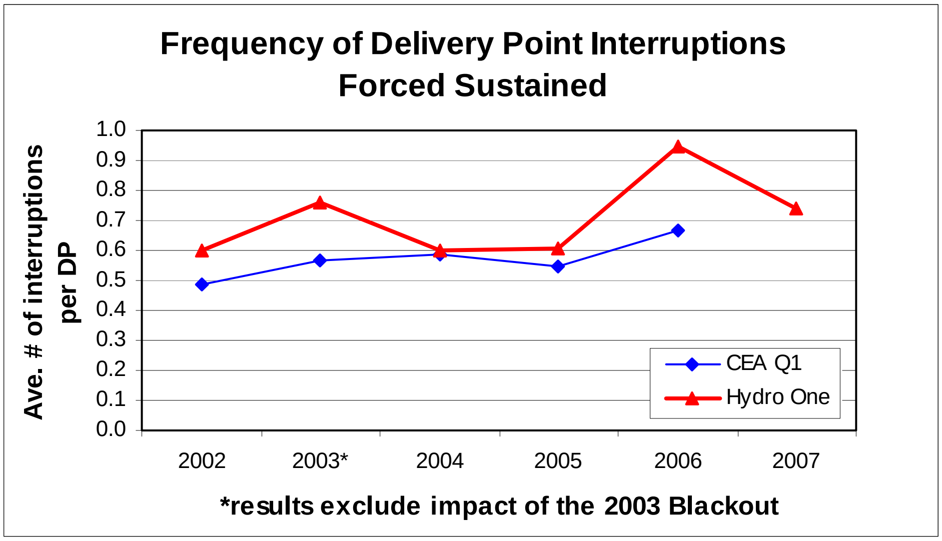
b) Are the CEA survey participants (reference (i), page 8) the "utility comparables" identified in reference (ii)? If so, please re-do Figures 4 and 5 from reference (i) so as to compare Hydro One Networks' performance against the CEA's first quartile performance.

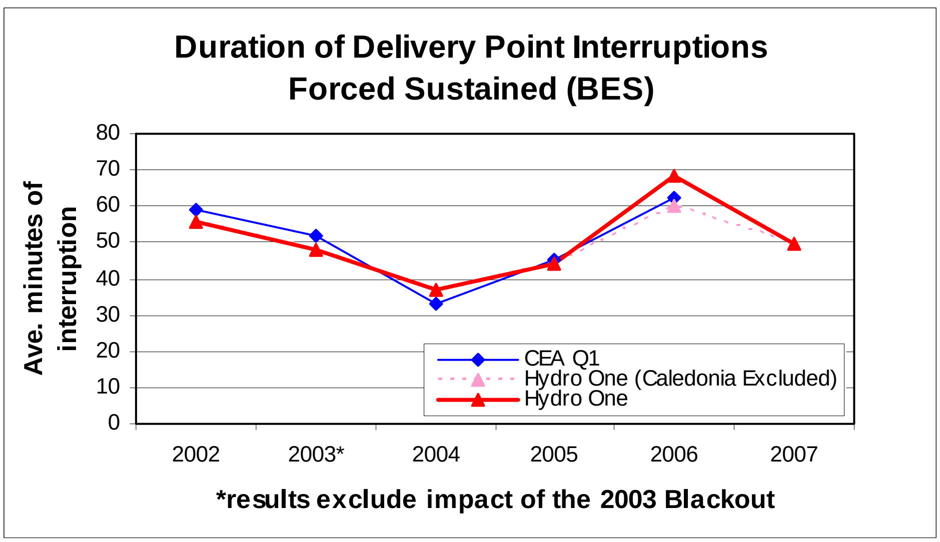
c) Based on the comments on page 13 (reference (i)) regarding the nature of Hydro One Networks' transmission system, why is it reasonable to expect Hydro One Networks' reliability performance to be in the first Quartile – as targeted in reference (i)?

Response

a) Yes there is a difference. Serious Lost Time Injuries are a subset of Lost Time Injuries and are injuries resulting from incidents in the 6 targeted high-energy categories (electrical incidents, preventable motor vehicle accidents, falls from a different level, falling objects, incidents involving work equipment & asset equipment failure).

b) The CEA survey participants (reference (i), page 8) include the "utility comparables" identified in reference (ii). Figures 4 and 5 from reference (i) have been re-plotted (below) to show Hydro One performance against CEA first quartile performance of the comparable utilities.





c) It is part Hydro One’s strategy to be in the First Quartile to assist its customer attain their goals by providing them with a high level of reliability. While as noted in the reference (i) it will be a challenge, it is a target in our search for, and implementation of, better and best practices.

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

Interrogatory

Reference: Exhibit A/Tab 15/Schedule 1, Appendix C

Issue Number: 2 & 3 & 4 (per PO #2, page 2)

a) With respect to pages 5-6, please clarify the cost responsibility for improving Group Performance outliers. Does Hydro One Networks cover the full cost of remedial action to improve Group CDPP standards to: i) the minimum standard or the established standard (per Table 1)?

Response

a) Hydro One covers the costs associated with remedial action on the original design required to improve delivery points determined to be outliers according to the Group CDPP Standard criteria. Any costs associated with changing the original design to improve reliability performance will be limited to the present value of three years worth of transformation and/or transmission line connection revenue associated with the delivery point.

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

Interrogatory

Reference: Exhibit A/Tab 15/Schedule 2, Attachment 1

Issue Number: 3.3

a) Page 18 sets out the results of the benchmark analysis. Please provide a schedule that for the Asset Replacement metrics and those Cost Metrics that are express in percentage terms sets out the average (two-year) results for Hydro One Networks' based on its 2009-2010 Application.

Response

The following schedules provide the average (two-year) results for Hydro One Networks' based on its 2009-2010 Application.

Cost Metrics (2 year average - 2009 and 2010)	Hydro One
2-yr Avg Trans Lines and Subs Capital + O&M spending per Asset	9.9%
2-yr Avg Trans Lines and Subs Capital Additions per Asset	7.7%
2 yr Avg Trans Lines and Subs O&M per Asset	2.2%

Asset Replacement Rates (2 year average - 2009 and 2010)	Hydro One
2-yr Avg Trans Lines Capital Additions per Asset	7.4%
2-yr Avg Trans Lines Replacement Capital Spending per Asset	1.5%
2-yr Avg Trans Subs Capital Additions per Asset	7.9%
2-yr Avg Trans Subs Replacement Capital Spending per Asset	3.3%

The increases in the metric percentages as shown in the schedule is primarily due to the significant increase in Development Capital in 2009 and 2010 over 2004-2006 amounts. The two major contributors to the increases are:

- The new 500 kV Bruce to Milton Double Circuit Transmission Line (2009-$ 170.3M and 2010 $ 263.1);

- The 2009 and 2010 expenditures for $226.2M and $246.5M respectively towards the Inter Area Network Transfer Capability excluding the Bruce-Milton Project.

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

Interrogatory

Reference: Exhibit A/Tab 16/Schedule 2, Attachment 1, pages 31-35

Issue Number: 2 & 3 & 4 (per PO #2, page 2)

a) Please calculate the Hydro One Network values for the four productivity measures (per Table 8) using 2009 and 2010 data.

Response

The productivity indicators used for the comparisons in the Mercer/ Oliver Wyman study for Hydro One and its peer group are based on actual values, such as MWh sold. The data to be used for the calculation of the 2009 and 2010 indices are not available.

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

Interrogatory

Reference: Exhibit A/Tab 16/Schedule 1

Issue Number: 3.1 & 3.2 & 4.1 & 4.2

a) With respect to pages 5-6 and Table 1, for the years 2005-2008, how much of the incremental savings in each year is expected to continue through to the 2009 and 2010 tests years and, therefore, are embedded "savings" (per page 5, lines 9-14)?

b) Are the measures set out on pages 10-11 meant to be calculated specifically for Hydro One Networks' Transmission business or just for Hydro One Networks' overall?

c) With respect to pages 10-11, please provide a schedule that sets out for the years 2006-2010 based on Hydro One Networks' transmission business:
   - Total Asset Management Costs relative to Total Work Program
   - Total CF&S costs relative to Total Networks' program costs

   For the years 2008 - 2010, please provide references as to where the data used in the calculations can be found in the Application.

Response

a) A cumulative total of $22.9M of savings is expected to be carried through in 2009 and 2010 and is reflected in work program costs in those years. The savings shown in Table 1 are calculated on a year-over-year incremental basis. For example, if the cost savings of a new initiative are $2M in its first year of implementation, and continues as $2M of similar savings in future years, it would be noted on the table as $2M in the first year, and zero in the next and subsequent years. If the savings were to increase from$2M in the first year to $3M in the second year, the incremental saving recorded for the second year would be $1M.

b) The measures set out in Exhibit A/Tab 16/Schedule 1 pages 10-11 are calculated for Hydro One Networks' overall business, which includes the Transmission business for all the measures except smart meters and vegetation management.

c) The schedule below provides the calculated values from 2006 to 2010 based on Hydro One Networks current application data years.

Measures	2006	2007	2008	2009	2010
Total Asset Management Costs relative to Total Work Program	3.1%	2.5%	2.7%	2.7%	2.8%
Total CF&S costs relative to Total Networks' program cost	4.7%	3.9%	4.4%	3.8%	3.7%

Data for "Total Asset Management Costs relative to Total Work Program" is found in "Exhibit C1,Tab 2, Schedule 8, Page 3".

Data for "Total CF&S costs relative to Total Networks' program cost" in found in "Exhibit C1, Tab 2, Schedule 6, Page 2".

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

Interrogatory

Reference: Exhibit A/Tab 18/Schedule 1

Issue Number: 1.1

Preamble:
With respect to the Settlement Agreement Undertaking regarding Export and Wheel Through Tariffs, the Application (page 1) states that Hydro One will file to modify the rates after the study undertaken by the IESO has been reviewed and approved by the OEB. However, the terms of the Settlement Agreement were that:
"It is agreed that the IESO will make its report available to the Board upon completion which will be no later than June 1, 2009 with the results of reciprocal arrangement negotiations and the study including recommendations for an appropriate ETS tariff. Hydro One Networks Inc. remains responsible for seeking changes to its approved transmission revenues and rates and will do so as part of the 2010 transmission rate-resetting process period, following the publishing of the study."

a) Does Hydro One Networks agree that, after the IESO has published its study, it is Hydro One Networks that is responsible for preparing an Application to the Board for a modified ETS tariffs and that the study will be reviewed the Board as part of its consideration of said Application?

b) If not, please clarify what Hydro One Networks' views regarding the process after the IESO has completed its study and made it available to the Board.

Response

a) Hydro One agrees that it is responsible for preparing an Application to modify the ETS tariff, however, as stated in Exhibit H1, Tab 5, Schedule 1, page 2, lines 5 and 6, it is Hydro One's expectation that the review and approval of the IESO study will be completed prior to Hydro One filing such an Application.

b) Hydro One expects the Board will initiate a process to review and approve the IESO recommendations from the ETS tariff study.

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

Interrogatory

Reference: Exhibit B1/Tab 1/Schedule 1, page 3

Issue Number: 4.4

a) Please provide a schedule that sets out how much of the deemed long-term debt for 2009 ($205.8 M) and 2010 ($0.3 M) is affiliate debt callable on demand and how much is the remaining amount of debt required to balance the total financing with rate base.

b) Hydro One Networks has valued the short fall between the actual debt level (including affiliate debt) and deemed debt level at the deemed cost of long-term debt. Other alternatives include: i) using an interest rate equivalent to the short-term cost debt and ii) using the average cost of actual long-term debt. Please provide references to Board decisions/guidelines that specify how such shortfalls should be treated for purposes of calculating the average cost of debt that support Hydro One Networks' approach.

Response

a) The entire amount of the deemed long-term debt for 2009 ($205.8M) and 2010 ($0.3M) is the remaining amount of debt required to balance the total financing with rate base.

b) Neither of the alternatives suggested by VECC in their question are in compliance with the Board's determined methodology and decisions.

Hydro One is in compliance with section 2.1.1 of the December 20, 2006 Report of the Board on Cost of Capital which allows for a total of 60% total debt as part of rate base, comprised of 4% short term debt and 56% long term debt. As indicated on page 9 of the Cost of Capital report, the Board determined that the short term debt amount will be fixed at 4% of rate base. Using alternative i) would not be in compliance with this decision as short term debt would deviate from the prescribe 4% level.

The portion of long term debt (56% of rate base) is comprised of actual third party debt at its actual contracted rate (as per page 13 of the Cost of Capital report) plus deemed long-term debt. This approach has been employed by the Board, as shown in Exhibit 1.3 of the Implementation of Decision with Reasons in EB-2006-0501, dated September 26, 2007.

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

Interrogatory

Reference: Exhibit B2/Tab 1/Schedule 2, page 6

Issue Number: 4.4

a) Please explain why, for debt forecast to be issued in 2009 and 2010, the longer term (higher cost) debt is issued first and the shorter term (lower) cost debt issued later in each year.

b) What would be the impact on the average cost of debt for 2009 and 2010 if the shorter term/lower cost debt was issued first in each year?

Response

a) Longer term debt issues have a smaller investor base and a greater price sensitivity to changes in interest rates compared to shorter term debt, making it relatively more difficult to issue. It is a prudent planning assumption, for debt forecast to be issued in 2009 and 2010, to attempt to issue the more difficult longer term debt first, and then complete the issuance of the relatively less difficult shorter term debt.

b) If the shorter term/lower cost of debt was issued first in each year, the 2009 average cost of debt would be 5.85% and the 2010 average cost of debt would be 5.78%.

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

Interrogatory

Reference: i) Exhibit C1/Tab 2/Schedule 1, pages 4-5
ii) EB-2006-0501, Exhibit C1/Tab 2/Schedules 2 and 5

Issue Number: 3.1 & 3.2

a) Please provide a schedule that compares the breakdown of the approved Sustaining OM&A spending for 2007 (per reference (ii), Schedule 2, page 7) with the actual level of Sustaining OM&A for 2007 using a similar break down. Please explain the variances by line item, noting where the higher spending for storm response and other unforeseen asset needs are reported.

b) Please explain the increase in Operations OM&A as between the 2007 approved level and the 2007 actual level. In particular what gave rise to the more than 35% increase in Operations Support OM&A?

c) Please provide a schedule that compares the breakdown of the approved Shared Services and Other OM&A spending for 2007 and 2008 (per reference (ii), Schedule 5, page 4) with the actual level of Shared Services and Other OM&A for 2007 and 2008 using a similar break down. Please explain any major variances by line item.

Response

a)

Sustaining OM&A

$ millions	**Board Approved 2007**	**Actual 2007**	**Variances**
Stations	128.5	134.2	5.7
Lines	48.4	47	(1.4)
Telecommunications	14.2	15.8	1.6
Engineering & Environmental Support	9.0	8.9	(0.1)
Total	**200.1**	**205.9**	**5.8**

Variance explanations:

Stations (Over-spent by $5.7M).

- Primarily due to the accomplishment of additional work on the 750 MVA autotransformer remediation work program.

Lines (Under-spent by $1.4M)

- Primarily due to less work being done than initially anticipated on the overhead line maintenance programs associated with the corrective work on the 230 kV line between London and Sarnia.

Telecommunications (Over-spent by $1.6M)

- Primarily due to the increase in planned work, such as the costs of administering maintenance and leased contracts, as well as the increased cost of corrective maintenance work, which is largely attributable to increased failures and the lack of vendor support and difficulty in obtaining spare parts as assets approach their end-of-life.

b) The actual spending for operations OM&A in 2007 was $49.7 million as compared to the Board Approved amount of $45.8M. This is an increase in overall spending by $3.9M or 9%.

The 9% increase in "actual" overall spending for Operations OM&A in 2007 was as a result of:

- The 35% increase in Operations Support OM&A discussed below;
- Increased resources to develop the Health, Safety and Environment work program to ensure compliance with Occupational, Health and Safety Legislations, and Hydro One's Policies and Standards.

The 35% increase in spending for Operations Support OM&A was the result of:

- An increase in field switching costs associated with the accomplishment of the increasing work program for the Transmission system;
- A one-time cost associated with the field switching of Transmission equipment located in OPG's facilities in Niagara Falls.

c) Below is a schedule comparing the 2007 and 2008 approved Shared Services & Other OM&A to the 2007 Shared Services and Other OM&A contained within this current filing.

Description	2007			2008		
	Approved	Actual	Variance	Approved	Bridge	Variance
Common Corporate Functions & Services	40.8	39.7	(1.1)	40.9	45.8	4.9
Customer care	1.6	1.2	(0.4)	1.6	1.6	0.0
Asset Management	58.2	55.7	(2.5)	57.3	72.1	14.8
Information Management Services	45.9	43.1	(2.8)	43.9	47.7	3.9
Cornerstone		2.7	2.7		3.1	3.1
Cost of Sales	10.5	14.5	4.1	9.9	12.4	2.5
Other	(89.6)	(70.5)	19.2	(96.5)	(106.3)	(9.9)
Total Shared Services and Other Costs	**67.4**	**86.4**	**19.0**	**57.1**	**76.4**	**19.2**

Hydro One has defined 'major variance' to be a variance greater than 1% of their 2007 Transmission Financial Statements OM&A ($423 million) in line with the OEB's *Filing Requirements for Transmission and Distribution Applications (EB-2006-0170)*.

Variance Explanation:

- 2007 Cost of Sales $4.1M
  As noted in Exhibit E1, Tab 1, Schedule 2, the associated costs for the External Revenues are the cost of sales. The 2007 variance is due to the additional work for Bruce Power and Pickering, transformer assembly for ABB and work associated with revenue meter upgrades at various sites. Please refer to Exhibit I, Tab 11, Schedule 5 for further explanation of the Engineering and Construction activities in 2007.

- 2007 Other $19.2M
  The 2007 Other variance of $19.2M is primarily due to $16M lower Overheads Capitalized.

- 2008 CCF&S $4.9M
  The variance is primarily due to increases in Corporate Finance, Human Resources and Corporate Communications functions. Please refer Exhibit I, Tab 6, Schedule 33 part (a) for further explanation of the variance.

- 2008 Asset Management $14.8M
  The $14.8M variance is primarily due to increases in System Investment, Business Integration and the Strategy and Conservation functions. Please refer to Exhibit I, Tab 6, Schedule 34 for further explanation.

- 2008 Other ($9.9M)
  The 2008 Other variance of ($9.9M) is primarily due to the impact of the one-time accounting adjustment related to the Inergi Pension Plan and the productivity

inititative offset by the lower amount of Overhead Capitalized (mainly due to the lower common costs used to calculated actual overheads capitalized). Please see Exhibit I, Tab 2, Schedule 9 part (b) for a summary of 2007 Other actuals.

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

Interrogatory

Reference: i) Exhibit C1/Tab 2/Schedule 2, pages 3-30 (Stations)
ii) EB-2006-0501, Exhibit C1/Tab 2/Schedule 2, page 7

Issue Number: 3.1

a) With respect to reference (i), page 11 (lines 24-28), what specific information led Hydro One Networks to conclude that a significant increase in spending levels for Spill Containment System Commissioning and Emergency Response programs is required for 2009 and 2010?

b) With respect to reference (i), pages 15-16, please provide the following:
- The number of transformers that have/will undergo mid-life refurbishment in 2005, 2006, 2007, 2008, 2009 and 2010.
- The number of failures of large 750 MVA transformers annually in the last few years.
- The number of transformers that have/will be replaced annually over the period 2005-2010.

c) With respect to reference (i), pages 16-17, please provide the following:
- The number of breakers (by type) that have/will undergo planned maintenance in 2005, 2006, 2007, 2008, 2009 and 2010.
- The number of breakers (by type) that have/will be replaced annually over the period 2005-2010.

d) With respect to reference (i), pages 19 and 22, given that compliance with new cyber standards is required by the end of 2009, why are 2010 costs for Cyber Security 30% higher than those for 2009?

e) With respect to reference (i), pages 25-28, please provide:
- Evidence to support the contention that an increasing number of Ancillary Systems are “moving through their mid-life region”.
- Evidence that an increasing number of such systems are reaching end-of-life.
- An explanation as to why the replacement of ancillary systems reaching end of life is “delayed” (page 28, lines 3-5).

Response

a) Testing of existing spill containment systems has shown that 50% of the systems tested failed Hydro One’s leak standards. Many of these systems have reached premature end-of-life (EOL) and our inspection programs have determined that many sheet plastic spill containment liners are now deteriorated and non-functional. Please see Interrogatory Exhibit I, Tab 4, Schedule 9, section c) for a complete description of the funding of these programs.

b) The number of midlife transformer refurbishments that Hydro One conducted from 2005 to 2008 and plans for 2009 and 2010 are as follows:

	2005	**2006**	**2007**	**2008**	**2009**	**2010**
Number of Midlife Transformer Refurbishments	0	0	1	4	8	6

The number of 750 MVA autotransformer failures that occurred from 2005 to 2008 are as follows:

	2005	**2006**	**2007**	**2008**
Number of 750 MVA Autotransformer Failures	1 (Trafalgar T15)	1 (Pinard T1)	0	0

The following table shows the number of power transformer replacements that Hydro One made from 2005 to 2008 and plans to make in 2009 and 2010. The counts from 2005 to 2008 also include those transformers that Hydro One replaced due to failures.

	2005	**2006**	**2007**	**2008**	**2009**	**2010**
Number of Replacements	2	9	5	7	11	8

The number of replacements shown in the above table includes replacements made under the Power Transformers and Station Re-Investments categories.

c) The following table shows the number of breakers (by type) that have/will undergo planned maintenance in 2005, 2006, 2007, 2008, 2009 and 2010:

	2005	2006	2007	2008	2009	2010
AIR	237	242	239	294	253	253
GIS	18	21	16	22	19	19
METALCLAD	127	125	142	106	125	125
OIL	1076	947	1422	1080	1131	1131
SF6	219	261	335	214	257	257
VACUUM	1	2	3	1	2	2

The following table shows the number of breakers (by type) that have/will be replaced annually over the period 2005-2010.

	2005	2006	2007	2008	2009	2010
AIR	0	4	3	2	6	10
OIL	3	4	4	11	13	15
GIS	0	0	0	9	6	0
METALCLAD	0	9	0	0	7	7
SF6	0	0	0	4	8	25
VACUUM	0	0	0	0	0	5

d) The costs are lower in 2009 because not all of the Cyber Security assets and annual review processes required by the standards are fully operational until the end of 2009. They are fully operational for the entire year in 2010, which leads to the increased funding.

e) The table below shows the percent of representative ancillary system assets in the mid life and end of life regions.

	% Mid Life Region	% End of Life Region
Grounding Grids	24	71
Batteries	50	16
Chargers	22	47
High Pressure Air Systems	65	33

The investments to replace Ancillary Systems reaching end-of-life have been prioritized in a manner that addresses the short and long term risks to these assets while allowing Hydro One to deliver the required Development program for the test years. The Ancillary System investments proposed for the test years will ensure Hydro One continues to meet its regulatory compliance and safety objectives.

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

Interrogatory

Reference: i) Exhibit C1/Tab 2/Schedule 2, page 5, Table 2
ii) Exhibit D1/Tab 2/Schedule 1, Attachment 1
ii) EB-2006-0501, Exhibit D1/Tab 2/Schedule 1, Appendix A

Issue Number: 3.1

a) With respect to the Power Equipment and Ancillary Systems categories set out in Table 2 (reference (i)), please provide a schedule that compares the findings of the 2006 and 2008 asset condition assessments for the assets covered by each of these categories. Please comment on the extent to which the increase in spending requirements for 2009 and 2010 over those planned (per EB-2006-0501, Exhibit C1/Tab 2/Schedule 2, page 10) or actually spent (reference (i)) is supported by a deterioration in asset condition.

Response

a) Please see the response to Interrogatory Exhibit I, Tab 6, Schedule 51.

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

Interrogatory

Reference: i) Exhibit C1/Tab 2/Schedule 2, pages 30-50 (Lines)
ii) EB-2006-0501, Exhibit C1/Tab 2/Schedule 2, page 37

Issue Number: 3.1

a) The current Application indicates that the Planned Corrective Maintenance activities for 2009 and 2010 are related to the 500 kV lines between Barrie and Sudbury and the 230 kV circuits between London and Sarnia (reference (i), page 45). These are the same two projects that were identified in the 2007-2008 Application (reference (ii)) as requiring funding in 2007 and 2008. Furthermore, it appears that total spending for 2007 and 2008 in this category was $7.5 M less than approved (i.e., $10.8 M vs. $18.3 M). Please explain why the project was not completed in 2007-2008 as originally planned.

Response

The primary reason for the difference between the planned spending levels in ED-2005-0501 and the 2007 actual and 2008 projected is as a result of delays in the corrective work on the 230 kV line between London and Sarnia. The original plan included $8.0 million in spending on this line over these 2 years but actual spending amounted to $2.2 million. The reasons for the delays were as follows:

- The conclusive identification of damage to the inner stands of the conductor proved to be more difficult to detect in the field than originally projected. Equipment that had been used in the laboratory to identify conductor strand damage did not provide reliable results when used in the field and adjustments were required to weatherproof the equipment. This resulted in very little corrective work, about $0.1 million, completed during 2007.

- During 2008, outage availability coupled with a limited construction period reduced accomplishments below plan. For the most part, these circuits traverse farm land between Sarnia and London and access to these properties with large equipment is generally limited to the winter months when the ground is frozen and the fall when crops have been removed from the fields. During 2008 a wet fall made it difficult to cross farm lands without causing extensive damage to the fields. During 2009 more work is planned during the winter months to reduce the risk of under accomplishment.

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

Interrogatory

Reference: i) Exhibit C1/Tab 2/Schedule 2, pages 50-51
ii) EB-2006-0501, Exhibit C1/Tab 2/Schedule 2, page 47

Issue Number: 3.1

a) Hydro One Networks is requesting $10.2 M annually for Engineering and Environmental Support. The EB-2006-0501 Application included an increase in the level of funding for 2007 and 2008 to roughly $9.2 M per year based on the same rationale as presented in the current Application. However, average annual spending over the 2007-2008 period is only $8.2 M. Why is the rationale and resulting forecast in this Application more credible?

Response

Spending for Engineering and Environmental Support is generally based on the amount of Development capital planned. Spending on these activities is increasing to support the average 136% increase in Development capital in the test years over 2008, as indicated in Exhibit D1, Tab 3, Schedule 3. The 2008 bridge year Development capital was less than planned, which resulted in lower than planned spend in Engineering and Environmental Support.

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

Interrogatory

Reference: i) Exhibit C1/Tab 2/Schedule 3
ii) Exhibit F1/Tab 1/Schedule 2, page 1

Issue Number: 3.1 and 5.3

a) Will the costs of the pre-engineering work related to Darlington "B" GS ultimately be OPG's responsibility? If not, why not? If yes, why is it necessary to record these expenditures in a deferral account?

Response

a) The costs for any pre-engineering work that is specifically for the connection of Darlington "B" GS will be OPG's responsibility. However, essentially all of the pre-engineering work that Hydro One is undertaking at this time is related to the expansion of the Bowmanville switching station and the new 500 kV transmission circuits that are required between Bowmanville SS and the GTA and not specifically for the connection of Darlington "B" GS. As the proposed development work is associated with the major 500 kV backbone of the power system and serves all customers connected to the power system, it is appropriate to record the expenditures being incurred now in the deferral account. The only part of the pre-engineering being done now that would ultimately be recovered from OPG relates to the connection from the OPG synchronizing breaker into the switchyard.

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

Interrogatory

Reference: i) Exhibit C1/Tab 2/Schedule 6
ii) EB-2006-0501, Exhibit C1/Tab 2/Schedule 5, page 7

Issue Number: 3.2

a) Please provide the CCF&S costs allocated to transmission for the 2008 Bridge broken down as per reference (i), Table 1. Please also provide an explanation of any variances from the 2008 values included in the 2007-2008 Application (per reference (ii)) that are greater than 5%.

b) With respect to page 5, please provide the 2007 and 2008 allocation to the Transmission business for Finance costs.

c) With respect to page 13, what are the new HR programs anticipated for 2009 and what is the associated cost (lines 18-21)?

d) With respect to pages 16-17, has the methodology for allocating Corporate Communications costs to the transmission business been reviewed in light of the creation of the new First Nation and Métis Relations directorate? If yes, please provide the results. If not, why not?

e) With respect to pages 18-20, please explain why the Transmission business' costs for the General Counsel and Secretary function increase by 15% between the 2008 value (per reference (ii)) and the 2009 value in the current Application. The description in the current Application does not make note of any material change in activities or responsibilities.

f) With respect to pages 20-23, please explain why the Transmission business' costs for Regulatory Affairs (excluding OEB Assessments) increases from the $3.6 M for 2008 included in the 2007-2008 Application to $5.0 M for 2009 in the current Application.

g) With respect to page 27, Table 1, please explain the reason for the $21.5 M credit for "Other" in 2008.

Response

a) Please refer to the chart below for the CCF&S costs allocated to Transmission for the 2008 Bridge:

$M	EB-2006-0501	EB-2008-0272	Variance
Corporate Management	3.9	3.3	(0.6)
Finance	12.3	16.3	4.0
Human Resources	5.5	7.0	1.5
Corporate Communications	2.2	3.2	1.0
General Counsel & Secretariat	3.9	4.0	0.1
Regulatory Affairs	10.2	10.3	0.1
Corporate Security	1.4	1.3	(0.1)
Internal Audit	1.6	1.6	0.0
Allocated to Others		(1.2)	
Total	40.9	45.8	4.9

The overall increase is $4.9M from the last application and is primarily due to the following:

i. Corporate Management – the decrease is primarily due to a reduction in compensation levels. Please refer to Exhibit I, Tab 1, Schedule 2 for details.

ii. Finance – the increase is primarily due to the establishment of the Enablement unit, compliance and the conversion to IFRS.

iii. Human Resources – the increase primarily results from expanded work programs to support employee-related transactions and the management development program.

iv. Corporate Communications – the increase is primarily due to the establishment of the First Nations and Métis Relations department.

b) The allocation of Finance costs to the Transmission business is as follows:

2007 $11.8M
2008 $16.3M

c) In 2009 Human Resources will be undertaking the following new initiatives:

a. Women's Leadership Program ($0.2M)
b. Graduate Learning Program ($0.2M)
c. Recruitment initiatives ($0.2M)

d) The methodology for allocating Corporate Communications (including the First Nations and Metis Directorate) was included as part of the review by Black & Veatch and was confirmed that there is no change necessary for the cost allocation.

e) The increase in Transmission costs for the General Counsel and Secretariat in 2009 compared to 2008 is primarily due to the new records management initiative.

f) The increase in Regulatory Affairs costs is driven by an extremely aggressive regulatory program which includes this Transmission rate application, preparation and planning for future Transmission rate applications, the large transmission leave to construct the application for the Bruce to Milton project, several smaller leave to construct applications, and increased compliance reporting.

g) The $21.5M credit in Other is primarily due to:

- $10M credit relating to the one-time settlement associated with the transfer of pension assets to the Inergi Pension Plan
- $8M credit due to a 2008 stretch target

For a summary of the $21.5M credit in Other in 2008 please refer to BOMA Interrogatory #9, filed at Exhibit I, Tab 2, Schedule 9.

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

Interrogatory

Reference: i) Exhibit C1/Tab 2/Schedule 8
ii) EB-2006-0501, Exhibit C1/Tab 2/Schedule 5, page 42

Issue Number: 3.2

a) Please provide the Asset Management function costs allocated to transmission for the 2008 Bridge year broken down as per reference (i), Table 1. Please also provide an explanation of any variances from the 2008 values included in the 2007-2008 Application (per reference (ii)) that are greater than 5%.

b) With respect to Table 2 (reference (i)), what is the reason for the increase in costs between 2007 and 2008?

c) With respect to Table 3 (reference (i)), what is the reason for the increase in costs between 2007 and 2008?

d) With respect to Table 5 (reference (i)), what is the reason for the increase in costs between 2007 and 2008?

Response

Please see Table 1 below, which compares the allocation to Tx for Asset Management for EB-0272 and EB-0501. The explanations for variances for (a), (b), (c) and (d) are given in the rightmost column of the table.

Table 1
Asset Management Function ($ Millions)

Function/Service	Allocation to Tx (EB-0272)	Allocation to TX (EB-0501)	Variance	% > 5%	Explanation for Variance > 5%
	2008	**2008**	**2008**	**2008**	
Strategy & Business Development	6.5	4.3	2.2	Yes	Please see Exhibit I, Tab 4, Schedule 17 for variance explanation
System Investment	21.9	16.8	5.1	Yes	Please see Exhibit I, Tab 4, Schedule 17
Work Program Optimization	2.5	2.6	(0.1)	No	
Business Integration	13.8	9.2	4.6	Yes	Please see Exhibit I, Tab 4, Schedule 17
Business Transformation	1.8	1.2	0.6	Yes	Increased support for the Cornerstone project (staff).
Real Estate & Facilities	20.5	19.7	0.8	No	
Contracts & Business Relations	4.2	3.5	0.7	Yes	Please see Exhibit I, Tab 4, Schedule 17
Asset Management Processes and Policies	.9	0	.9	Yes	Please see Exhibit I, Tab 4, Schedule 17
Total Costs	**72.1**	**57.3**	**14.8**		

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

Interrogatory

Reference: i) Exhibit C1/Tab 2/Schedule 9
ii) EB-2006-0501, Exhibit C1/Tab 2/Schedule 5, page 60

Issue Number: 3.2

a) Please provide the Information Technology costs allocated to transmission for the 2008 Bridge year broken down as per reference (i), Table 1. Please also provide an explanation of any variances from the 2008 values included in the 2007-2008 Application (per reference (ii)) that are greater than 5%.

b) With respect to page 5 (reference (i)), please explain how the annual COLA cost factors relate to the increase in Base IT Sustainment Services costs shown in Table 2. For example, the COLA cost factor increases by $2.3 M from 2008 to 2009 but the cost increase in Table 2 is $4.9 M.

Response

a) Information Technology Summary of OM&A Expenditures ($ Millions)

Description ($ million)	**Bridge 2008**	**TX allocation**
Sustainment	71.5	30.5
Development	6.2	4.0
Business Telecom	17.2	8.1
IT Management & Project Control	9.1	5.2
Total Cost	**104.0**	**47.8**

Description ($ million)	**EB-2006-0501 ExC1/Tab2/Sched5/ Table 22 – 2008 Test**	**EB-2008-0272 ExC1/tab2/Sched 9/ Table 1- Bridge 2008**	**Difference Between EB-2008 and EB-2006**
Sustainment	57.7	71.5	13.8
Development	13.2	6.2	(7.0)
Business Telecom	17.1	17.2	0.1
IT Management & Project Control	7.7	9.1	1.4
Total Cost	**95.6**	**104.0**	**8.4**

<u>Comparison to EB-2006-0501</u>

Sustainment costs are higher than the original budget in EB-2006-0501 due to unbudgeted sustainment costs related to Cornerstone Phase 1; Hydro One's move to data storage as a service whereby storage services are purchased from Inergi rather than owned by Hydro One; higher than budgeted sustainment costs for the WEP application; and higher than budgeted COLA costs

Development costs are lower because a number of application enhancement projects have been deferred or removed due to functionality that will be provided through the Cornerstone project. Some of the costs budgeted in this area for application architecture, QA/QC and Bill 198 compliance have been moved to IT Management & Project Control

IT Management & Control Costs are higher as these cost now include application architecture costs, Bill 198 and QA/QC costs. Costs have also increased due to the addition of one additional security person in addition to the budgeted staff costs

b) COLA

The Inergi contract contains a fixed price schedule for each of the 10 contract years expressed in 2002 dollars. The annual COLA adjustment for 2009 is determined by multiplying the annual COLA factor for 2009 by the sum of the fixed price schedule for 2009 plus changes in scope and volume of services effective in 2009.

The COLA factor is "based upon the Statistics Canada Indices of total wages, salaries, and supplementary labour income in Ontario, and total number of employees in Ontario". Using 2001 as a base year, a COLA factor for each year is calculated by comparing the annual Statistics Canada Indices with the 2001 values. In accordance with the agreement, the 2008 Statistics Canada Indices are used for 2009.

The total increase in total IT Base sustainment costs between 2008 and 2009 is $4.9 million. The increase is comprised on the following:

COLA increase -	$2.3 million.
Scope and volume changes -	$2.4 million

Scope and volume changes relate to changes to the original scope and volumes for base services contracted in 2002.

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

Interrogatory

Reference: i) Exhibit C1/Tab 2/Schedule 11
ii) Exhibit E1/Tab 1/Schedule 2, pages 1-2

Issue Number: 2.2 and 3.2

a) Please explain why for 2009 and 2010 Engineering and Construction revenues equal costs, when reference (ii), page 1 suggests there is a margin built into the setting of revenues.

Response

The 2009 and 2010 plan for external revenue relating to engineering and construction support was formulated with the assumption that as little external work as possible would be contracted for. However, it was recognized that generator customers would still require Hydro One's support to meet some of their critical needs. The amount of $1.5 million was forecast for both 2009 and 2010 with the expectation that there would be very little margin made on this work. As a result, cost of sales was set equal to revenue.

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

Interrogatory

Reference: i) Exhibit C1/Tab 3/Schedule 2
ii) EB-2007-0681/Exhibits H-1-71 and H-12-20
iii) Exhibit A/Tab 14/Schedule 1, Appendix A, page 3

Issue Number: 3.3

a) Please provide updated responses for the interrogatories listed in Reference (ii) covering the years 2005 – 2010.

b) Please explain the variance between the 2008 Total Wages as reported in EB-2007-0681 ($580.7 M) and that reported in the current Application ($569.0 M).

c) With respect to reference (i), page 10, please provide the staffing level data and work program data that supports the 6% and 20% figures used at lines 17-19. Note: Where possible please provide cross references as to where the data can be found in the current Application.

d) With respect to reference (iii), when were the various incentive plans discontinued. Please reconcile the discontinuation of various incentive plans with the continuing increase in incentive plans costs (per reference (i), Table 3).

Response

a) i) The update to EB-2007-0681 Exhibit H-1-71 is provided below. As there was no approved Transmission Cost of Service application for 2005 and 2006, there are no "Board Approved" total wages for those years. As no total wages data was submitted with the EB-2006-0501 evidence, there are no "Board Approved" total wages for those years.

Total Wages
Hydro One Networks Inc.

M$	2005 Actuals	2006 Actuals	2007 Actuals	2008 Bridge	2009 Test	2010 Test
OM&A	242.7	281.4	302.3	341.4	353.5	371.9
Capital	155.2	177.9	193.2	227.6	235.7	248.0
Total	**397.9**	**459.3**	**495.5**	**569.0**	**589.2**	**619.9**

ii) The update to EB-2007-0681 Exhibit H-12-20 is provided in Attachment 1.

b) The primary driver of the difference is a lower estimate of 2008 overtime costs.

c) Please refer to Exhibit I, Tab 1, Schedule 44, parts d), e), b), c).

d) The Society Incentive Pay Plan was discontinued in 2003. The PWU's Incentive Plan was discontinued in 2005. The Incentive Pay costs in C1/Tab3/Schedule 2 relate to MCP short term incentive costs only. These costs change due to escalation and the changing number of MCP staff.

2005

REPRESENTATION	TOTAL NO. EMPLYS	TOTAL WAGES	% CHANGE	Average Overtime	Average Incentive	Benefits per EE
Building trades	594	34,788,694	33.51%	6,952		
MCP	322	41,337,068	-0.95%	459	17,628	3,855
PWU	3,280	262,822,737	-1.12%	13,393	811	2,876
SOCIETY	882	58,938,274	13.58%	2,767	54	2,352
Total	**5078**	**397,886,774**				

2006

REPRESENTATION	TOTAL NO. EMPLYS	TOTAL WAGES	% CHANGE	Average Overtime	Average Incentive	Benefits per EE
Building trades	598	39,153,993	12.55%	9,828		
MCP	476	59,707,957	44.44%	120	9,239	3,624
PWU	3,495	294,019,129	11.87%	16,901	1	2,901
SOCIETY	732	66,443,825	12.73%	2,030		3,390
Total	**5301**	**459,324,903**				

2007

REPRESENTATION	TOTAL NO. EMPLYS	TOTAL WAGES	% CHANGE	Average Overtime	Average Incentive	Benefits per EE
Building trades	740	50,810,389	29.77%	9,972		
MCP	524	67,717,643	13.41%	121	12,690	3,879
PWU	3,825	306,580,259	4.27%	13,439	0	2,788
SOCIETY	804	70,417,819	5.98%	2,955	8	2,629
TOTAL	**5893**	**495,526,109**				

2008

REPRESENTATION	TOTAL NO. EMPLYS	TOTAL WAGES	% CHANGE	Average Overtime	Average Incentive	Benefits per EE	
Building trades	730	51,627,475	1.61%	6,259			New MCP per EE
MCP	616	83,591,200.48	23.44%	0	13,798.70	4,034.00	1,398.00
PWU	4,479	341,300,340	11.32%	11,784		3,318.00	
SOCIETY	1,056	92,480,984.40	31.33%	2,210		2,873.00	
TOTAL	**6,881**	**569,000,000**					

2009

REPRESENTATION	TOTAL NO. EMPLYS	TOTAL WAGES	% CHANGE	Average Overtime	Average Incentive	Benefits per EE
Building trades	860	62,646,051	21.34%	6,284		
MCP	630	87,362,959	4.51%	0	13,968	
PWU	4,298	336,638,268	-1.37%	12,344		
SOCIETY	1,132	102,552,721	10.89%	2,133		
TOTAL	**6920**	**589,200,000**				

2010

REPRESENTATION	TOTAL NO. EMPLYS	TOTAL WAGES	% CHANGE	Average Overtime	Average Incentive	Benefits per EE
Building trades	960	72,028,390	14.98%	6,290		
MCP	630	90,411,804	3.49%	0	14,762	
PWU	4310	346,278,642	2.86%	11,154		
SOCIETY	1172	111,181,164	8.41%	2,167		
TOTAL	**7072**	**619,900,000**				

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

Interrogatory

Reference: i) Exhibit C1/Tab 3/Schedule 2, pages 16-17
ii) OEB Decision with Reasons, EB-2006-0501, page 36
iii) OEB Staff IR #2

Issue Number: 1.1

a) What are savings in executive salary costs for 2007 and 2008 (relative to what was included in the EB-2006-0501 filing) as a result of Hydro One's acceptance of the Arnett Panel recommendations regarding executive compensation?

Response

a) Please refer to Exhibit I, Tab 1, Schedule 2.

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

Interrogatory

Reference: i) Exhibit C1/Tab 3/Schedule 2, Appendix A

Issue Number: 3.3

a) Please confirm whether the $95 M value reported on page 3 for 2007 actual pension contributions and the $107 M value shown on page 2 for 2009 are comparable in terms of definition.
   - If no, please explain the difference and indicate what the 2007 cash pension cost that is equivalent to the $107 M value for 2009.
   - If yes, please explain the reason for increase from $95 M to $107 M.

b) Please provide the anticipated annual cash pension cost for 2008 broken down in a manner similar to that shown for 2009 and 2010 on page 2.

Response

a) Yes, the numbers are comparable in terms of definition. Pension costs, reflecting the Company's contribution to the pension fund, are based on an actuarial valuation as at December 31, 2006 for the years 2007, 2008 and 2009. Contributions for those years are based on (1) the level of base pensionable earnings in the year; and (2) a fixed amount for the deficiency in the plan. The difference between the $95M in 2007 and the $107M in 2009 reflects a higher level of base pensionable earnings, consistent with higher staff levels.

b) 2008

Corporate Pension Costs	Transmission	Distribution	Other	Total
OM&A	$ 26	$ 32	$ 3	$ 61
Capital	$ 18	$ 23	$ -	$ 41
	$ 44	$ 55	$ 3	$ 102

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

Interrogatory

Reference: i) Exhibit C1/Tab 4/Schedule 1
ii) EB-2007-0681/Exhibit H-13-26

Issue Number: 3.3

a) Please provide an updated response to the interrogatory listed in Reference (ii) covering the years 2005 – 2010.

b) With respect to reference (i), please provide a schedule similar to Table 1 for:
- Regional Line Maintainer
- Field Business Clerk
- MP4

Response

(a) Please see the tables below.

Service Providers – Standard Labour Rates

LINES	2005	2006	2007	2008	2009	2010
Regional Line Maintainer	92.00	91.00	103.50	111.00	109.00	112.00
Scheduling Tech (Grade 63)	92.00	91.50	108.50	117.50	115.00	118.00
Team Lead (Grade 62)	100.00	97.00	114.50	123.50	121.00	124.00
Field Business Clerk (Grade 56)	81.00	81.00	92.50	102.00	103.00	105.00
Supervising Tech (Grade 65)	101.50	102.00	118.00	126.50	123.00	127.00
Lines UTS II AND III	105.50	104.00	116.00	124.50	122.00	125.00
Truck Driver	75.00	71.00	94.50	104.50	104.00	106.00
COSR (Grade 59)	85.00	83.00	100.00	113.00	112.00	115.00
MP 4	125.00	121.00	143.50	160.00	159.00	166.00
MP 2	112.00	100.00	127.00	142.00	139.00	145.00
Grade 64	105.50	104.00	116.50	131.00	128.00	131.00
Meter Reader UTS II & UTS III	119.00	125.00	95.00	97.00	93.00	95.00
Meter Reader A	79.00	74.50	84.00	86.00	82.00	84.00
Meter Reader B	55.50	54.00	56.00	57.50	56.00	58.00
Hiring Hall Labourer	39.50	43.00	49.50	55.50	54.00	55.00
Hiring Hall Foreperson	63.50	65.00	75.50	84.00	80.00	82.00
Hiring Hall Journeyperson	59.00	61.00	67.50	75.50	72.00	74.00
Hiring Hall Apprentices	44.50	45.00	52.50	58.00	57.00	58.00
Hiring Hall Meter Reader	46.00	41.50	45.00	46.50	48.00	49.00
Students	25.50	30.50	34.50	41.50	39.00	40.00

STATIONS	2005	2006	2007	2008	2009	2010
Electrical Maintenance	103.50	97.00	107.00	118.00	118.00	121.00
Mechanical Maintenance	100.50	99.00	111.00	121.50	122.00	125.00
Civil Maintenance	99.50	87.00	105.50	117.00	114.00	117.00
MP2 / MP3	124.00	120.00	135.00	150.50	125.00	131.00
P&C (Tech) - PWU (Gr 65,66)	125.50	117.50	132.00	141.50	142.00	146.00
P&C (Technician) - PWU (Gr 64)	112.00	106.00	116.00	129.00	115.00	118.00
CMS Rigger	89.00	83.50	96.50	111.50	103.00	106.00
Clerk Grade 58	84.50	80.50	101.50	116.50	109.00	111.00
MP4 / MP5 / MP6	144.50	139.50	160.00	177.00	169.00	176.00
PWU (Grade 62, 63)	99.50	101.00	119.50	135.00	131.00	134.00
Hiring Hall Electrical Maintenance	67.00	70.00	71.50	79.00	80.00	82.00
Hiring Hall Labourer	55.00	57.50	67.00	74.50	77.00	79.00
Hiring Hall Apprentices	57.00	68.50	61.50	70.50	72.00	73.00
Hirig Hall Mechanical Maintenance	67.00	70.00	71.50	81.00	82.00	84.00
Hiring Hall Civil Maintenance	65.50	66.50	67.50	75.00	76.00	78.00
Student	38.50	41.50	51.00	59.00	61.00	62.00

FORESTRY	2005	2006	2007	2008	2009	2010
Regional Maintainer Forestry	100.50	98.50	105.00	110.00	109.00	111.00
Forestry - UTS II	115.00	113.50	109.50	125.50	119.00	122.00
Forestry - UTS III	108.00	106.50	119.50	117.00	113.00	116.00
Forestry Technician	105.00	101.00	102.50	105.50	106.00	109.00
Labourers	74.50	86.00	76.00	80.50	83.00	85.00
Hiring Hall Apprentices	58.00	58.50	54.00	55.00	59.00	61.00
Hiring Hall Labourer	46.50	50.00	48.00	53.00	53.00	54.00
Hiring Hall Elec Forester Journyperson	60.00	62.50	58.50	64.50	63.00	65.00
Hiring Hall Senior Foreman	62.50	68.00	69.50	73.50	74.00	76.00

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ENGINEERING	2005	2006	2007	2008	2009	2010
MCP	190.00	179.50	161.50	150.00	163.00	168.00
MP 1	91.50	83.50	101.00	98.00	94.00	99.00
MP 2	97.50	86.00	117.50	114.50	109.00	114.00
MP 3	104.00	97.50	131.50	128.50	123.00	129.00
MP 4	111.00	104.50	143.00	140.00	134.00	140.00
MP 5	118.50	120.00	162.50	159.00	151.00	158.00
MP 6	126.00	127.50	159.50	156.50	149.00	156.00
PWU GR 56	58.00	53.00	86.00	83.00	79.00	82.00
PWU GR 58	65.50	62.50	100.50	97.50	93.00	96.00
GR 60 / 61	0.00	69.50	104.00	101.00	96.00	99.00
PWU GR 64	93.00	83.50	119.50	116.50	110.00	113.00
GR 65 / 66	0.00	88.00	130.50	127.00	120.00	124.00
CADD OP 61	75.00	71.50	97.00	94.50	90.00	92.00
CADD OP 63	84.00	82.50	112.50	109.50	104.00	107.00
CADD OP 66	100.00	96.00	124.50	121.50	115.00	118.00
NON REGULAR PWU	53.50	59.00	61.50	48.00	58.00	60.00
NON REGULAR CADD OPERATOR	76.50	69.50	72.50	65.00	71.00	73.00
NON REGULAR M&P	110.00	100.00	85.50	73.00	82.00	85.00

CONSTRUCTION	2005	2006	2007	2008	2009	2010
MP4 Scheduling	92.00	90.50	0.00	0.00	0.00	0.00
Grade 64 Scheduling Technician	77.00	73.50	0.00	0.00	0.00	0.00
BTU - Groundman	0.00	59.50	59.00	61.00	62.00	63.00
BTU - Lineman	0.00	62.00	59.00	61.00	62.00	63.00
BTU - Foreman	68.50	71.50	67.50	69.50	69.00	71.00
BTU - Labourer	50.50	53.00	56.00	57.50	58.00	59.00
BTU - Carpenter	53.00	55.50	58.50	60.00	60.00	62.00
BTU - Operator	54.00	52.50	58.00	59.50	60.00	61.00
BTU - Iron Worker	62.50	61.50	61.00	63.00	63.00	64.00
BTU - Electrician	59.50	61.00	58.00	60.00	60.00	61.00
BTU - Teamsters	57.00	54.00	58.00	59.50	60.00	61.00
NON REGULAR PWU	75.00	68.50	46.00	48.00	49.00	50.00

Hydro One Networks Fleet Rates

Please note: There were five changes in rates for 2008 from values reported in H13-26. These are highlighted, in the table below.

Class Grouping	Description	2005	2006	2007	2008	2009	2010
107	AUGER,UP TO 6' DIAMETER	65	75	100	102	85	85
118	UTILITY BOAT WITH INBOARD	35	35	55	56	11	11
119	WORK BOAT WITH INBOARD	40	40	55	56	11	11
139	LINE TENSIONER	20	30	50	51	42	42
141	LINE TENSIONER QUAD 2.5 TON	20	20	20	20	20	20
146	TRUCK MTD LINE PULLER TENSIONER	20	20	20	20	3	3
148	QUAD REEL STANDS	20	20	20	10	10	10
149	LINE PULLER TENSIONER,TRL MTD 11-20#	20	20	50	50	50	50
280	ALL TERRAIN CRANE			96	100	29	29
282	ROUGH TERRAIN CRANE 21-35 TON			80	84	26	26
285	ALL TERRAIN CRANE			100	100	100	100
340	DIESEL GENERATOR	5	5	5	5	5	5
396	SELF PROPELLED WORK PLATFORM >=25'	20	20	20	21	30	30
581	FELLER BUNCHER	100	15	15	28	16	16
594	MUSKEG TRACTOR 4 TON PAYLOAD	25	25	22	23	23	23
596	MUSKEG TRAILER 8 TON PAYLOAD	1	1	10	10	3	3
597	MUSKEG WITH RBD	125	110	150	153	90	90
598	MUSKEG WITH RBD (834)	55	55	86	88	63	63
607	BAKHO TRACTOR	10	15	15	15	30	30
629	ALL TERRAIN VEHICLE	8	8	8	8	2	2
641	FARM TRCT DSC MASSEY FERGUSON. 3600	55	55	55	55		
642	FARM TRACTOR 70 HP	40	40	32	32	17	17
653	TRACKED VEHICLE 4 TON PAYLOAD	30	25	25	38	36	36
655	MUSKEG WITH AD (827)	90	100	125	141	65	65
658	CRAWLER LOADER 2 1/4 TO 4 CU YD	10	10	10	20	15	15
659	TRACKED CRAWLER/CARRIER	55	55	70	71	75	75
666	TRACKED CRAWLER 100 TO 120 HP	55	55	70	71	75	75
672	TRACKED CRAWLER 120 TO 150 HP	25	25	25	25	77	77
688	RUBBER TIRED TRACTOR WITH BAKHO	20	20	20	31	24	24
689	FARM TRACTOR WITH ATTACHMENTS	20	20	16	16	7	7
690	LOADER TRACTOR	10	10	15	15	37	37
693	TIMBERJACK/TREE FARMER	50	40	58	59	50	50
694	TREE FARMER(PHASING OUT)	50	50	45	45	23	23
696	BRUSH CUTTER RUBBER TIRED	60	60	54	54	43	43
697	TRACTOR MERI CRUSHER-LIGHT	50	80	102	104	105	105
698	FELLER BUNCHER TIMBERJACK 608S	110	110	110	110	75	75
699	SWING GRAPPLE TRACK SKIDDER		85	85	104	100	100
702	TRACTOR FORKLIFT	12	12	14	15	10	10
845	INTERMEDIATE CAR	5	6	7	7	5	5
860	PERSONNEL CARRIER MISC	14	12	12	13	10	10

Class Grouping	Description	2005	2006	2007	2008	2009	2010
880	MISC VAN	15	15	11	12	12	12
881	CARGO VAN/PERS CARRIER 5-8 PASS	7	7	7	7	7	7
886	VAN W/25' AERIAL LADDER	15	15	15	19	15	15
890	PICKUP MISC	14	12	12	12	10	10
900	MISC SERVICE TRUCK	20	20	20	20	18	18
904	SERVICE TRUCK WITH AD (821)	10	20	20	34	15	15
907	SERVICE TRUCK WITH AD	45	40	50	51	40	40
913	14' STAKE TRUCK	15	20	21	21	20	20
916	STAKE TRUCK WITH RBD (831)	44	45	44	45	50	50
918	STAKE TRUCK W/ART CRANE	24	20	25	39	35	35
919	STAKE TRUCK WITH CRANE/RBD		40	25	39	35	35
920	FORESTRY TRUCK MISC	25	25	30	51	30	30
925	FORESTRY TRUCK WITH AD (822)	48	50	60	60	40	40
930	LINE MTNC TRUCK WITH 826	85	75	76	77	70	70
931	LINE MNTC TRUCK WITH 200ft AD	260	255	251	253	196	196
932	LINE MTNC TRUCK WITH AD	65	50	60	63	50	50
938	LINE MTNC TRUCK WITH RBD (832)	60	60	60	63	50	50
950	TRUCK TRACTOR W/SLIDING 5TH WHEEL	55	55	55	51	55	55
960	MISC	15	18	20	29	20	20
975	HOUSE TRAILER		5	5	5	5	5
976	HORSE VAN TRAILER		5	5	5	5	5
977	TRAILER, OIL FILTRATION	10	15	15	20	20	20
985	UTILITY TRAILER 11800 KG	7	7	7	12	12	12
986	LOW BED UTIL TRAILER 13-29 TON	11	12	12	17	17	17
988	LOW BED TRAILER 40 TO 50 TON	30	26	26	35	35	35
990	STORAGE TANK TRAILER	12	12	12	20	20	20
994	LOW BED FLOAT TRAILER 100 TON	5	7	7	11	11	11
995	TRAILER, DEGASSIFIER	5	5	5	13	13	13
	A STAR HELICOPTER	1,400	1,400	1,500	1,550	1,550	1,550
	LONG RANGER HELICOPTER	1,200	1,200	1,300	1,350	1,350	1,350

Material Surcharge Rates

	2005	2006	2007	2008	2009	2010
Forestry	10%	10%	10%	10%	10%	10%
Lines	16%	12%	12%	14%	15%	15%
E&CS	5%	5%	5%	5%	5%	5%
Stations	5%	5%	5%	5%	7%	7%

(b) Please see the schedules below.

Regional Line Maintainer

	2005*	2006	2007	2008	2009	2010
Payroll Obligations	$64.69	$65.50	$70.42	$71.42	$66.90	$68.72
Contractual time away from work	$8.22	$8.31	$8.46	$8.93	$9.04	$9.63
Time not directly benefiting a specific Program or Project	$4.43	$4.44	$4.83	$5.95	$6.56	$6.99
Field Supervision and Technical Support	$2.31	$2.52	$9.07	$11.08	$13.01	$13.05
Support Activities	$9.72	$10.24	$10.71	$13.61	$13.49	$13.62
Labour Rate	**$89.37**	**$91.00**	**$103.50**	**$111.00**	**$109.00**	**$112.00**

* Note: 2005 standard labour rates included $2.63 for facilities and telecom allocations not shown above.

Field Business Clerk

	2005	2006	2007	2008	2009	2010
Payroll Obligations	$50.49	$52.57	$56.83	$57.80	$55.17	$56.61
Contractual time away from work	$7.00	$7.37	$6.01	$6.10	$6.82	$6.66
Time not directly benefiting a specific Program or Project	$4.33	$4.50	$4.61	$5.53	$6.77	$6.62
Field Supervision and Technical Support	$3.26	$3.36	$11.14	$14.77	$16.52	$17.22
Support Activities	$12.53	$13.20	$13.91	$17.80	$17.72	$17.89
Labour Rate	**$77.61**	**$81.00**	**$92.50**	**$102.00**	**$103.00**	**$105.00**

* Note: 2005 standard labour rates included $3.39 for facilities and telecom allocations not shown above.

MP4

	2005	2006	2007	2008	2009	2010
Payroll Obligations	$93.90	$92.02	$102.85	$106.37	$101.53	$106.52
Contractual time away from work	$11.96	$11.99	$12.06	$12.92	$13.55	$14.27
Time not directly benefiting a specific Program or Project	$2.15	$2.13	$4.27	$8.02	$9.47	$9.97
Field Supervision and Technical Support	$2.72	$3.03	$10.82	$14.83	$16.66	$17.28
Support Activities	$11.22	$11.82	$13.51	$17.87	$17.79	$17.96
Labour Rate	**$121.96**	**$121.00**	**$143.50**	**$160.00**	**$159.00**	**$166.00**

* Note: 2005 standard labour rates included $3.03 for facilities and telecom allocations not shown above.

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

Interrogatory

Reference: i) Exhibit C1/Tab 5/Schedule 1, pages 2-3 and Attachment 1
ii) EB-2006-0501/Exhibit C1/Tab 3/Schedule 1, page 5

Issue Number: 3.2

a) Schedule 1 reports total 2009 and 2010 CCF&S costs for Transmission of $47.5 M and $47.9 M respectively. However, in Attachment 1, total Transmission CCFS costs for 2009 and 2010 are reported as $95.1 M and $96.0 M respectively. Please reconcile.

b) With respect to reference (i), Attachment 1, the total 2009 CCFS costs for transmission are reported as $95.1 M. The comparable value from the EB-2006-0501 Application appears to be $73.4 M for 2008. Please confirm that this is the case and, if so, explain the more than 30% increase over the one year.

Response

a) Please refer to OEB interrogatory # 37, filed at Exhibit I, Tab 1, Schedule 37 for the 2009 reconciliation.

The table below reconciles the 2010 amounts used in the two references.

2010 ($ Millions)	Total	Transmission	Distribution	Others
Total CCF&S Costs [as per Table 1 (ExhC1/Tab5/Sch1/p.2)]	96.8	47.9	46.3	2.6
Inergi	104.7	26.3	77.3	1.1
Other Common Corporate Costs (e.g. Telecom, IMIT, Supply Chain Services)	78.0	21.8	16.8	39.4
Total CCFS Costs [as per Table 2 (Exh C1/Tab5/Sch1/Attach1/p6)]	**279.5**	**96.0**	**140.4**	**43.1**

It is confirmed that the comparable value for 2008 Transmission total CCFS cost is $73.4M (Reference EB-2006-0501, Exhibit C1, Tab 5, Schedule 1, Attachment A, Table 2, page 2). The increase is primarily due to the follow:

- $6M increase in CF&S costs
- $5M increase in Inergi costs
- $9M impact is due to the inclusion of Facilities & Real Estate and Business Transformation Function in the Rudden Review but reflected in evidence under Asset Management.

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

Interrogatory

Reference: i) Exhibit C1/Tab 5/Schedule 2, Attachment 1

Issue Number: 3.4

a) With respect to page 3, was the Asset Management time study used for this Application the same one that was used for EB-2006-0501. (Note: The evidence for both cases makes reference to an April 2006 study)
   - If yes, please explain why the percentage of costs to be capitalized are different as between the two applications.
   - If no, please explain what changed in terms of the studies used.

b) A comparison of the current Overhead Capitalization Study with that performed for EB-2006-0501 shows an increase in both the transmission labour and spending percentages associated with capital versus OM activities between 2007 and 2009 & 2010. Page 3 states that the current study used the results of a 2006 time study. Why are the results of the time study performed in 2006 still appropriate to use for 2009 and 2010? Why wouldn't it be reasonable to assume there would be a need to increase the proportion of Asset Management costs that are capitalized.

c) Please provide cross-references as to where the Application's description of OM&A costs the values for the following inputs used in the Overhead Capitalization study can be found:
   - Total CCFS costs (line 16)
   - Asset Management costs (line 46)
   - Operating and Outage Management (line 50)
   - Customer Care Management (line 51)

d) What was the basis of the percentages (lines 56 &57) used to establish the amount of Operating & Outage Management and Customer Care to be capitalized?

Response

a) The Asset Management time study used in this application is consistent with the time study filed in EB-2006-0501 Exhibit J, Tab 1, Schedule 52, Attachment 1. There is no change in the methodology used. The percentage of costs to be capitalized are different because of changes to the common costs to be allocated (numerator) and changes to the work programs (denominator).

b) Between 2006 and 2009 the volume of work performed by the Asset Management group will have increased, however there is not a material shift in the time worked on Capital projects versus OM&A programs. B&V concluded that the 2008 Asset Management Time Study results were "reasonably similar" to the April 2006 study.

c)

- Total CCFS costs (line 16)
  The $95.4M as referenced in line 16 is the transmission portion of CCFS costs as detailed in Exhibit I, Tab 1, Schedule 37. The $95.4M used in the overhead rate capitalization methodology was a preliminary assumption. Over the course of the budget process, the total CCFS costs were updated to $95.1M which represents updates to common work programs. The impact of this $0.3M difference to the overhead capitalization rate is a difference of 0.02%

- Asset Management costs (line 46)
  Real Estate and Facilities and Business Transformation are excluded from the Asset Management calculation shown on line 46 since these two functions now reside under Common Corporate Costs. The $74.0 used in the review, is therefore the $123.6M Asset Management function total as shown in Exhibit C1, Tab 2, Schedule 8, page 3, Table 1 minus the Real Estate and Facilities function amount of $46.5M and the Business Transformation function amount of $3.1M ($123.6M - $46.5M - $3.1M = $74.0M).

- Operating and Outage Management (line 50)
  The $43.0 used in the review, is the total Operations amounts, whereby only 77% or $33.1M, as per the time study used in EB-2006-0501, is applied to Transmission. The $33.1M is shown as Operations in Exhibit C1, Tab 2, Schedule 4, page 3, Table 1.

- Customer Care Management (line 51)
  The $8.0M as referenced in line 51 was a preliminary assumption. Over the course of the budget process, the total Customer Care Management costs were updated to $7.8M. The $7.8M is shown as total Customer Care Management in Exhibit C1, Tab 2, Schedule 7, page 1, Table 1.

d) The basis for the percentages in lines 56 and 57 is the actual time study which was filed in EB-2006-0501 Exhibit J, Tab 1, Schedule 5, Attachment 1.

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

Interrogatory

Reference: i) Exhibit C1/Tab 3/Schedule 2, page 10
ii) Exhibit C1/Tab 5/Schedule 2, Attachment 1

Issue Number: 3.3

a) Please explain how the transmission labour dollars values reported on lines 28-30 of Reference (ii) – Attachment A were determined and how they relate to the total labour dollars reported in reference (i).

b) Using the methodology from reference (ii) please provide a schedule that sets out the total TX labour costs for 2006-2010 and, for each year, breaks down the results between capital and O&M.

Response

a) The Transmission labour dollars reported on lines 28-30 of reference (ii) - Attachment A are based on estimates of labour costs (including pension and benefits) directly charged to core OM&A and Capital work programs by the Forestry, Stations, Lines and Engineering and Construction Services groups. The Total Wages in reference (i) is a calculated amount based on the wage costs for all Dx and Tx staff on the Hydro One Networks payroll at year-end.

b) Tx Labour Costs

In M$	**2006**	**2007**	**2008**	**2009**	**2010**
Capital	130.1	235.0	279.7	309.2	429.2
OM&A	100.8	123.6	112.5	143.7	149.1
Total	230.9	358.6	392.2	452.9	578.3

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #44 List 1

Interrogatory

Reference: Exhibit C1/Tab 6/Schedule 2, Attachment 1

Issue Number: 3.6

a) Please provide a "qualitative discussion/explanation" as to why the depreciation charge for Communication Equipment has increased by $1.9 M.

Response

The increase of $1.9 million for Communication Equipment depreciation is largely attributable to a combination of growth in the plant investment between December 31, 2005 and December 31, 2007 and an associated reduction in the reserve ratio. Plant increased from $315.2 million to $325.2 million. The impact of this $10 million increase was magnified by the impact of reducing the ratio of the recorded reserve to the plant investment (*i.e.*, reserve ratio) from 44.6 percent to 35.3 percent. The impact of these factors, which served to increase depreciation, was partially offset by the impact of changing the remaining life of these assets from 12.36 years to 12.75 years. The net change in these parameters produced an increase in the accrual rate from 4.48 percent to 5.07 percent. The increase in the accrual rate produced an increase of $1.9 million in the depreciation charge for Communication Equipment.

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

Interrogatory

Reference: Exhibit C2/Tab 6/Schedule 1, Attachment 2, page 1

Issue Number: 3.5

a) Please explain how the CCA classes used by Hydro One Networks account for the changes in CCA rates introduced in the Federal 2007 budget.

Response

Hydro One has reflected the CCA rates introduced in the Federal 2007 budget in its calculation of income taxes for the two test years in this application.

For 2007 and 2008, Hydro One accounts for the applicable Federal 2007 budget changes in Class 45 CCA rates via the disposition of the deferral and variance accounts. See Exhibit F2, Tab 1, Schedule 3 and response to Exhibit I, Tab 2, Schedule 25, page 2.

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

Interrogatory

Reference: Exhibit D1/Tab 1/Schedule 3, page 2

Issue Number: 4.3

a) Please provide cross references as to where in the application the 2009 and 2010 cost values for each of the line items in Table 1 can be found.

Response

The following table cross-references the 2009 and 2010 cost values found in Table 1 of Exhibit D1, Tab 1, Schedule 6, page 2 with the application.

	Reference	**2009 Test Year Amount**	**2010 Test Year Amount**
Expenses			
OM&A Expenses	Exhibit C2, Tab 2, Schedule 1, page 2	435.2	449.7
Removal costs	Exhibit C2, Tab 5, Schedule 1, page 1, line 5	17.8	17.9
Environmental Remediation	Exhibit C2, Tab 5, Schedule 1, page 1, line 9	2.1	1.8
Interest on Long term debt	Exhibit B2, Tab 1, Schedule 2, page 5, line 30 [2009] and page 6, line 31 [2010]	220.4	248.5
Income and capital tax	Exhibit C2, Tab 1, Schedule 1, page 1 - sum of lines 3 and 4	48.3	54.0

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

Interrogatory

Reference: Exhibit D1/Tab 3/Schedule 1, pages 4-6

Issue Number: 4.1

a) With respect to page 5, since total Development spending in 2007 was less than the Board approved level, why was it necessary to redirect resources from Sustainment to Development work?

b) Please indicate what sustainment spending was foregone in 2007 and discuss how the choice of these projects is consistent with:
   - The asset condition assessment results (i.e., were the spending reductions in areas that were not deemed to be high priority assets and/or assets not in poor condition?)
   - Hydro One Networks' overall investment prioritization process outlined at Exhibit A/Tab 14/ Schedule 4, page 3.)

c) Given the inability to complete planned Development work in 2008, why weren't more resources redirected to Sustainment activities, particularly in light of the significant under spending in that area in 2007?

d) With respect to page 6 (lines 15-19), specifically what actions will increase work execution capability in 2009 and 2010 relative to 2008. Please address labour and material availability separately.

e) Please provide a schedule of the major development projects that were delayed in 2007 and 2008 and indicate which ones were impacted by labour and material resource availability and which ones were impacted by an inability to obtain the required outages from the IESO.

Response

a) While not all of the approved 2007 Development work was completed, Hydro One found it necessary to redirect many engineering resources to respond to a number of unplanned equipment failures (transformer failure and fire at Pinard, Building fire at Pickering TS, capacitor bank transient faults at Richview TS). The engineering required to deal with these equipment failures was redeployed from lower priority Sustainment and Development work. This resulted in delayed spending on materials and construction activities leading to lower overall spending in both Sustainment and Development.

b) All Sustainment work planned for 2007 was based on identified needs, which are in part driven by asset condition. The decision to defer work on Sustainment investments took into consideration the short term and long term risks, while ensuring that all work necessary to satisfy regulatory, safety and environmental objectives was completed. The areas of work contributing to reductions of sustainment investments are detailed in Exhibit D1, Tab 1, Schedule 2, and are as follows:

- less replacements of the end-of-life components in the Station System Re-investment programs;
- lower refurbishment and replacement of power transformers and other power equipment due to longer lead times;
- lower spending in transmission site infrastructure and support services; and
- lower spending at the Grid Operating and Control facilities.

The need for redirection as part of the overall prioritization process is discussed in Section 2.5 of Exhibit A, Tab 14, Schedule 5.

c) In 2008 Hydro One experienced a greater demand for Development work associated with customer driven generator connections, which required significant engineering efforts above what had been anticipated. Additional pressures to those experienced in 2007 also occurred with respect to completing the 2008 Development Capital program (e.g. Lambton and Nanticoke project delays in order to mitigate generation outage needs). As such, it was not possible to redirect additional resources to the completion of the Sustainment program.

d) The actions being taken to increase work capacity are discussed in the response to interrogatory Exhibit I, Tab 4, Schedule 28. Work program capability improvements that are labour related include: recruitment of additional engineers, increased use of external contracts to supplement internal engineering resources, the greater use of standardized designs to reduce labour needs, multi-year releases (to enable more effective labour scheduling), work bundling and resource modelling to enable more optimum scheduling and lower resource needs for a given work program size.

Work program capacity improvements that are material related include: standardized designs which utilize common materials, long lead material tracking to ensure adequate material lead times are in-place at project initiation and the use of longer term planning.

e) Major development projects that were delayed in 2007 and 2008 include the following:

Project	Delayed by			
	resource availability	materials availability	outage availability	third party
Lakehead TS: Install SVC		Yes		Yes
230kV Underground TxLines: John TS x Esplanade TS			Yes	
Cambridge Preston TS: Add 250MVA, 230-115kV Transformer				
Detweiler TS: Install 245MVAR Shunt Capacitor Bank	Yes		Yes	
Orangeville TS: Install 245MVAR Shunt Capacitor Bank	Yes			
Sarnia Generation Connection Plan			Yes	
New Feeders at Existing TS's			Yes	
Kingston Gardiner TS		Yes		Yes
Whitby TS		Yes		
Buchanan TS, Talbot TS	Yes			
Holland TS				Yes
Pleasant TS Expansion		Yes		
Red Lake TS		Yes		Yes
Line Connections	Yes			
Portland Energy Centre			Yes	

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #48 List 1

Interrogatory

Reference: i) Exhibit D1/Tab 3/Schedule 1, page 7

Issue Number: 4.1

a) What was the originally planned in-service date for the NRP?

b) What are the current system implications, in terms system reliability and congestion, of the NRP not coming into service when planned?

c) At what point in time do the implications become more significant?

Response

a) The original planned in-service date for the Niagara Reinforcement Project (NRP) was June 2007.

b) The Independent Electricity System Operator (IESO) as the Reliability Coordinator for Ontario will direct operations to manage the reliability impacts as a result of the NRP project not being complete. In its latest 18-month outlook[1], the IESO notes that the completion of this project will "increase the transfer capability of the transmission interface connecting the grid in the Niagara zone to the grid in the Hamilton area by about 800 MW. This enhancement will permit increased imports from New York of at least 350 MW, and up to 800 MW, depending on the load and generation dispatch in Ontario."

c) The IESO has not identified at what point in time the implications become more significant.

[1] 18-Month Outlook - An Assessment of the Reliability of the Ontario Electricity System - From October 2008 to March 2010, IESO_REP_0480v1.0, September 23, 2008.
http://www.iemo.com/imoweb/pubs/marketReports/18MonthOutlook_2008sep.pdf

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #49 List 1

Interrogatory

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

Issue Number: 4.1

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

Response

Hydro One's risk based planning process is not based on the assessment and mitigation of risk associated with Sustainment projects in isolation. As discussed in Exhibit A, Tab 14, Schedule 5, all projects and programs, regardless of category (sustainment, development, operations and shared services), are subject to the prioritization process, with the exception of minimum levels, which are automatically placed in the Investment Plan proposal. The prioritization methodology then ranks the combined set of projects and programs, based on their ability to mitigate incremental risk related to the business values, and proceeds to a consideration of financial constraints and resource availability in determining which investments will become part of the asset plan.

Sustainment related projects and programs are included in the ranked list of all projects and programs subjected to this investment prioritization process. Sustainment projects and programs are not prioritized as a separate group and so it is not possible to speculate on the effects of raising or lowering the level of funding applicable to Sustainment projects and programs alone.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #50 List 1

Interrogatory

Reference: i) Exhibit D1/Tab 3/Schedule 2, page 5
ii) EB-2006-0501, Exhibit D1/Tab 3/Schedule 2, page 6

Issue Number: 4.1

a) Please explain why 2008 Sustaining spending on Stations is $30 M higher than the OEB approved level. Is the additional work all carry over from 2007 or is some of it new work not included in the 2007-2008 plan?

Response

The 2008 Stations spending shown in Exhibit D1, Tab 3, Schedule 2 of the current application includes Telecommunications spending, which was shown as a separate item in EB-2006-0501 (Exhibit D1, Tab 3, Schedule 2, pg. 31). As such, the 2008 Stations Sustaining capital spending is projected to come in $14M higher than the OEB approved level.

The increase in capital spending is primarily due to an investment to prevent copper theft that was not included in the 2007-2008 plan. As noted in Exhibit D1/Tab 3/Schedule 2 (Sustaining Capital), pages 5-6, this $30.5 million investment was undertaken to "improve security to address the significant increase in copper theft at Hydro One Transmission transformer stations that represents a financial loss to the company, threatens the reliability of the transmission system and presents a significant safety risk to Hydro One Transmission personnel and the general public."

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #51 List 1

Interrogatory

Reference: i) Exhibit D1/Tab 3/Schedule 2, page 5 and page 6, lines 8-20
ii) EB-2006-0501, Exhibit D1/Tab 2/Schedule 1, Appendix A

Issue Number: 4.1

a) With respect to the spending for Circuit Breakers, Station Re-Investment and Power Transformers in Table 2 (reference (i)), please provide a schedule that compares the finding of the 2006 and 2008 asset condition assessments for the assets covered by each of these categories.

b) Please comment on the extent to which the increase in spending requirements for 2009 and 2010 over those planned (per EB-2006-0501, Exhibit D1/Tab 3/Schedule 2, page 6) for 2007 and 2008 is supported by a deterioration in reported asset condition.

c) What other facts have changed since the 2007-2008 Application that support the need for increased spending in these areas?

Response

a) The tables below provide a comparison of the finding of the 2006 and 2008 Health Indices for assets covered by the Circuit Breakers, Station Re-Investment and Power Transformer programs.

The Health Index (HI) is used as a measure of the effectiveness of past O&M and capital decisions and it is one indicator of asset health. Actions are undertaken whenever the HI's deem assets to be in poor or fair condition. These actions may include additional monitoring, maintenance, refurbishment or replacement. However, the HI does not factor in all available asset information, and as such it is not the sole driver for investment decisions.

Notwithstanding a good or very good HI rating, specific investments may still be initiated as a result of the additional asset information not captured by the HI. This information includes performance data (both individual asset and asset family), additional condition data, and requirements with respect to obsolescence.

Equipment	Year	"HI<30"	"30<=HI<50"	"50<=HI<70"	"70<=HI<85"	"85<=HI<100"
Power Transformers	2008	0.3%	1.8%	1.9%	9.4%	86.6%
	2006	0.5%	2.1%	4.8%	13.9%	78.7%
Air Blast Circuit Breakers	2008	0.0%	1.1%	4.4%	28.9%	65.6%
	2006	0.0%	2.3%	5.3%	38.2%	54.2%
High Voltage Switches	2008	0%	1%	16%	53%	31%
	2006	0%	0%	6%	29%	64%
High Pressure Air Systems – Condensers	2008	0.0%	16.1%	0.0%	6.9%	77.0%
	2006	0%	14%	0%	6%	80%
SF6- Breakers	2008	0.0%	0.4%	8.6%	14.0%	77.1%
	2006	0.0%	0.0%	0.0%	9.0%	91.0%
Metalclad Breakers	2008	0.0%	0.0%	1.4%	8.2%	90.4%
	2006	0.0%	0.0%	1.4%	8.6%	90.0%
Metalclad Bus	2008	0.0%	0.0%	0.0%	24.0%	76.0%
	2006	0.0%	0.0%	5.3%	10.5%	84.2%

b) As noted in the response to a) above, investments are driven by the condition of individual assets, performance data (both individual asset and asset family), and requirements with respect to obsolescence.

Investments in circuit breakers are driven by deterioration in the condition and performance of the equipment. Data suggesting poor condition includes; deterioration of gaskets, leaking seals, degraded insulation, mechanical and electrical wear and higher maintenance cost. Data suggesting poor performance includes failures, increased outage rates and the results of breaker timing tests. Other factors considered are technical obsolescence, lack of manufacturer support and spare parts.

Investments in transformers are driven by deterioration in the condition and performance of the equipment. Data suggesting poor condition includes deteriorating equipment protective coatings, corrosion, insulation degradation, leak rates, excessive vibration and gas accumulation in the oil. Data suggesting poor performance includes increased outages rates as well as internal winding and under load tap changer failures.

c) Please refer to response b).

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #52 List 1

Interrogatory

Reference: i) Exhibit D1/Tab 3/Schedule 2, page 5 and page 6, lines 8-20
ii) EB-2006-0501, Exhibit D1/Tab 2/Schedule 1, Appendix A

Issue Number: 4.1

a) With respect to Overhead Lines Refurbishment and Component Replacement, the Application states (page 49) that projections based on condition data and reliability performance are for structure replacements to increase in the test period. Please provide a data comparison (i.e., asset condition and reliability data submitted for EB-2006-0501 which supported the 2007-2008 expenditure levels versus current asset condition and reliability data) that substantiates this resported change in circumstances and supports the increased need.

Response

Prior to 2007 there was no way other than a visual inspection to assess the condition of wood pole arms on the 230 kV Gulfport structure. This was highlighted in Exhibit D1, Tab 3, Schedule 2, page 22 of 34 and in Interrogatory J-7-9 section c) of EB-2006-0501. It is very difficult to identify internal rot using visual inspections. Photograph #1 below shows a 230 kV Gulfport structure and photograph #2 shows internal rot of a wood pole arm.

During 2007 a testing method was developed that involved drilling into the arm from a helicopter platform to determine the degree of sound wood (see photograph #3) . Since that time 1,250 structures have been inspected and 27% of the arms have been assessed to be at end of life. There are currently about 3,800 structures of this type in service that have not been replaced. It is estimated that about 1,000 wood structures are at end of life based on the 1,250 test results. Condition information to this level of detail was not available when EB-2006-0501 was submitted.

From 2003 to 2005 the highest number of failures during any year was 4 as highlighted in Exhibit D1, Tab 3, Schedule 2, page 22 of 34 of EB-2006-0501. This has since increased to 7 wood arm failures during 2007.

The additional condition data as noted above is the reason for the increase in wood structure replacement from the 1,450 identified in Exhibit D2, Tab 2, Schedule 3, S16 of EB-2006-0501, which included 381 of Gulfport structures, to the proposed 1,650 identified in Exhibit D2, Tab 3, Schedule 3, S30 of the current application, which includes 948 Gulfport structures.

Photograph #1

Photograph #2

Photograph #3

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #53 List 1

Interrogatory

Reference: i) Exhibit D1/Tab 3/Schedule 2, pages 53-58
ii) EB-2006-0501, Exhibit D1/Tab 3/Schedule 2, page 21 & 26

Issue Number: 4.1

a) Please confirm that the Port Hope to Peterborough project was included in the 2007-2008 Application with a 2009 completion date.

b) What is the reason for the project's delayed completion until late 2010?

Response

a) Yes. The reference is to the Port Hope Jct to Sydney TS which was included in the 2007 – 2008 Application with a 2009 completion date.

b) The Port Hope Jct to Sydney TS project was deferred by one year in order to address the deteriorated conductor on circuit L1S that needed a quicker response. Details of the L1S project are provided in Exhibit D2, Tab 2, Schedule 3, Investment Summary S34.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #54 List 1

Interrogatory

Reference: i) Exhibit D1/Tab 3/Schedule 1, page 2
ii) Exhibit D1/Tab 1/Schedule 1, page 3

Issue Number: 4.3

a) Please provide a schedule that integrates the capital spending and fixed asset information in the above two references into one continuity schedule that shows capital spending as well as in-service additions for each year and shows assets under construction at year end as well as total fixed assets in-service.

Response

For Capital Expenditure information, please see Exhibit D1, Tab 3, Schedule 1, Table 1.

For in-Service Additions, please see Exhibit D1, Tab 1, Schedule 1, Table 2.

For Assets under construction at year-end, please see Exhibit D2, Tab 3, Schedule 3.

For total fixed assets in-service, please see Exhibit D1, Tab 1, Schedule 1, Table 2.

Transmission Capital - $M.

	Historic			**Bridge**	**Test**	
Description	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**
Capital Expenditures (D1-3-1)	349	402	560	693	944	1,074
In-Service Additions (D1-1-1)	351	315	490	505	794	962
Closing Construction work-in-progress (D2-3-3)	297	376	448	636	786	898
Total Gross Fixed Assets in-service (D1-1-1) closing	9,510	9,793	10,104	10,566	11,314	12,246

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #55 List 1

Interrogatory

Reference: i) EB-2006-0501, Exhibit D1/Tab 3/Schedule 3

Issue Number: 4.3

a) Please provide a listing of development capital projects identified in the EB-2006-0501 Application as coming into service in 2006, 2007 or 2008 and approved by the OEB for inclusion in rate base in the 2007 and/or 2008 test years. For each project please indicate whether or not it is currently projected to be in-service December 31, 2008. If not, please indicate its status.

b) Please provide a listing of any development projects (with total costs greater than $3 M) that were not included the EB-2006-0501 Application but are projected to be in-service by December 31, 2008. For each such project, please provide an investment justification and also explain why project was unforeseen but necessary to complete by 2008.

Response

a) Outlined below are the current in-service projections for the development capital projects identified in Proceeding EB-2006-0501 that were approved by the OEB for inclusion in the rate base for the test years 2007 and/or 2008.

Investment Name	**Current Status***
Lakehead TS: Install SVC	Delayed. *In-service expected for late 2010.*
Downtown Toronto New Transmission Supply: 230kV U/G Transmission Lines John TS x Esplanade TS	In-service.
Preston TS – Add 230/115kV Autotransformer	In-service.
Detweiler TS – Install 245MVAR Shunt Capacitor Bank	In-service.
Orangeville TS – Install 245MVAR Shunt Capacitor Bank	In-service.
Sarnia Generation Connection Plan	In-service *(exception: replacement of one breaker at Lambton TS which is expected in-service for March 2009)*
Kingston Gardiner TS – Add Transformation Capacity	In-service.
Whitby TS – Add Transformation Capacity	In-service.
Buchanan TS: Install 4 Feeder Positions	In-service.
Talbot TS: Build new Transformer Station	In-service.
Holland TS – Build new 230/44kV TS	Delayed. *In-service expected for Mid 2009.*
Pleasant TS Expansion	In-service.
Red Lake TS – Increase Transformation Capacity 115/44kV TS	In-service.
Portlands Energy Centre (PEC) Connection Plan	In-service.

** where "Current Status" indicates the projected in-service status as of December 31, 2008.*

b) Only one development capital project (with net total costs greater than $3M), which was not explicitly included in Proceeding EB-2006-0501, is projected to be in-service by December 31, 2008.

Investment Name	**2006 ($M)**	**2007 ($M)**	**2008 ($M)**	**Net Total ($M)**
Toyota Woodstock: Supply to new plant	0.3	2.7	0.8	3.8

In Proceeding EB-2006-0501, load customer connection projects with net expenditures less than $3 million in either 2007 or 2008 were accounted for under the "Other" category in Exhibit D1, Tab 3, Schedule 3, Table 5, and not separately identified.

In 2005, Toyota Motor Manufacturing Canada Inc. requested Hydro One to connect their new plant in Woodstock, Ontario to Hydro One's transmission system via a line tap from an existing 115kV transmission circuit.

This project was initially expected to be completed in 2007; however delays in acquiring the necessary land rights resulted in a delay of one year before a permanent transmission supply connection could be constructed. In order to satisfy Toyota's schedule, a temporary supply connection was installed along government land allocated for long-term highway expansion to allow the plant to go in-service.

This project is funded by the customer and the capital contribution was determined in accordance with the requirements of the Transmission System Code.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #56 List 1

Interrogatory

Reference: Exhibit D1/Tab 3/Schedule 3

Issue Number: 4.1

a) With respect to projects D3 and D4, what it the latest in-service date required for each project in order to provide necessary support voltage and accommodate new generation in SW Ontario?

b) With respect to project D5, please explain further the statement that the project is “partially discretionary”.

c) Also, how reasonable is the projected December 2010 in-service date for project D5?

d) Why are projects D7 and D8 required to be in-service on the currently planned dates?

e) What is the impact of projects D9 and D10 on the revenue requirement for 2010? It appears that these projects will only proceed if the OPA recommends them. When must this recommendation be received by in order to meet a 2010 in-service date?

Response

a) Project D3 is to install seven new 230 kV capacitor banks in southwestern Ontario during 2009 and project D4 is to make modifications to the Bruce Special Protection System by mid-2010. In EB-2007-0050, Exhibit B, Tab 3, Schedule 1, Page 1-3, the Ontario Power Authority (OPA) noted that these projects are part of the “Near-Term” and “Interim Measures” required to incorporate the forecast increased amount of generation that are expected to become available in the Bruce Area. The need date in the referenced filing for these facilities is 2009 and that need date is linked to the return to service dates for Bruce “A” GS units 1 and 2. In its latest 18-month outlook[1], the IESO forecasts return to service dates for these as 2009-Q3 for unit 2 and 2010-Q1 for unit 1. Hence 2009-Q3 is the latest in-service date for both of these projects to meet the stated purposes.

[1] 18-Month Outlook - An Assessment of the Reliability of the Ontario Electricity System - From October 2008 to March 2010, IESO_REP_0480v1.0, September 23, 2008. http://www.iemo.com/imoweb/pubs/marketReports/18MonthOutlook_2008sep.pdf

b) Project D5 is Cherrywood TS x Claireville TS: Unbundle 500 kV circuits. As stated in Exhibit D1, Tab 3, Schedule 3, Page 14, the project combines both discretionary and non-discretionary components. The discretionary component covers the unbundling of 500kV Circuits since it is aimed at reducing congestion, due to the new Hydro Quebec interconnection and renewable energy projects in eastern Ontario. The non-discretionary component covers the work required to correct existing deficiencies at Cherrywood TS and Claireville TS.

c) The forecast December 2010 in-service date is considered achievable.

d) Projects D7 & D8 are the installation of Static Var Compensators at Porcupine TS and Kirkland Lake TS (D7) and the Installation of Series Capacitors at Nobel TS (D8). They are required by 2010 to accommodate both the existing generation and the expansion of the lower and upper Mattagami River plants which according to a letter that Hydro One Networks received from the Ontario Power Authority on May 20, 2008, are forecast to be in-service between 2010 and 2013

e) Projects D9 & D10 are the installation of shunt capacitors at Algoma TS (D9) and Mississagi TS (D10). These projects contribute $20M to the 2010 in-service additions, which accounts for about $1.0M in the 2010 revenue requirement. A recommendation from OPA to proceed with these is expected to be received in early 2009, which will allow the forecast in-service date to be met.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #57 List 1

Interrogatory

Reference: i) Exhibit D1/Tab 3/Schedule 3, page 24 (lines 18-19)2
ii) Exhibit D1/Tab 3/Schedule 3, Tables 4 & 5

Issue Number: 4.1

a) Load customer connections are funded through a combination of future rate revenues and a capital contribution. Generation connection customers only pay for their connections through capital contributions. However, while the capital contributions from load customer represents almost half the gross cost of their projected connections (Table 4) – for generation customers capital contributions represent only 38% of the projects' costs. Please reconcile.

Response

Hydro One follows the requirements of the Transmission System Code (TSC) to determine capital contributions from load and generation customers. Load and generation work are treated differently in the TSC, which is the basis for the disparity noted in the question.

The TSC specifies that a generator is accountable for the costs associated with the facilities required to connect to Hydro One system, but any work required at Network stations to incorporate that generator, including protection related work, is recovered from the Network cost pool. The generation connection Project D38, described in Exhibit D2, Tab 2, Schedule 3, contains elements that are pool funded. The cost of the pool funded component totals $19.0 M, while the balance of the $32.8M project cost is paid for by the generator via a capital contribution. This accounts for the relatively lower percentage of capital contribution for generation customers noted in the interrogatory.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #58 List 1

Interrogatory

Reference: i) Exhibit D1/Tab 3/Schedule 4, page 5
ii) EB-2006-0501 – Exhibit D1/Tab 3/Schedule 4, page 5 and Project Sheet O1

Issue Number: 4.1

a) In the EB-2006-0501 Application the NMS Upgrade project had an in-service date of 2008 and a total cost of $17.5 M. The current Application calls for an in-service date of 2009 and a total project cost of $27 M. Please explain the increase in project costs.

Response

The additional cost of the NMS Upgrade is mainly due to additional system requirements stemming from the NERC Cyber Security standards, which were published subsequent to EB-2006-0501. The additional system requirements increased the scale and complexity of the underlying architecture, resulting in increased costs and a delay in the in-service date. The additional computing hardware installed to complete this project also resulted in increased need for computer room air conditioning and power supply upgrades at the OGCC and the Richview Backup Centre.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #59 List 1

Interrogatory

Reference: i) Exhibit D1/Tab 3/Schedule 5, pages 2-3
ii) EB-2006-0501 – Exhibit D1/Tab 3/Schedule 5, page 16

Issue Number: 4.1

a) With respect to reference (i), Tables 1 and 2, please provide a breakdown of the annual spending on Cornerstone between Phase 1 and Phase 2.

b) Please provide a schedule that sets out the actual capital cost of Cornerstone-Phase 1 and the projected cost as per the EB-2006-0501 Application for both the project's total costs and the transmission business' share. Please provide an explanation of the variance.

Response

a) Please refer to Exhibit I, Tab 1, Schedule 74, Part b).

b) Please refer to Exhibit I, Tab 1, Schedule 74, Part a).

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #60 List 1

Interrogatory

Reference: i) EB-2006-0501, Board Decision, page 49
ii) EB-2006-0501, Exhibit M/Tab 1/Schedule 1, page 18
(iii) Exhibit F1/Tab 1/Schedule 2, page 4

Issue Number: 5.1 and 1.1

a) As part of its EB-2006-0501 Decision the OEB approved the establishment variance/deferral accounts to:
   - Track customer capital contributions that could be required regarding the Cambridge Preston TS project (reference(i))
   - Track amounts paid out as result of Transmission System Code changes (references (ii) and (iii)).

   Please provide a status report for each of these accounts, including a year to year continuity schedule to December 31, 2008.

Response

a) Hydro One Transmission has not posted any transactions to either of these accounts. The balance in these accounts is nil.

Vulnerable Energy ConsumersCoalition (VECC) INTERROGATORY #61 List 1

Interrogatory

Reference: Exhibit F1/Tab 1/Schedule 1,page 3 (lines 10-11)

Issue Number: 5.1

a) Did the Tax Rate Changes account also reflect changes to the CCA rate for Class 1 as introduced in the 2007 Federal Budget? If not, why not?

Response

a) The Tax Rate Changes account did not reflect 2007 Federal Budget changes to CCA rate for Class 1 as these were not applicable to Hydro One. Property acquired after February 22, 2005 pertaining to transmission assets previously included in Class 1 are included in Class 47. See Exhibit C2, Tab 6, Schedule 1, Attachment 2, page 1.

Vulnerable Energy ConsumersCoalition (VECC) INTERROGATORY #62 List 1

Interrogatory

Reference: (i) EB-2006-0501 – Exhibit M/Tab 1/Schedule 1, page 18
(ii) EB-2006-0501 – Exhibit F1/Tab 2/Schedule 1, page 2

Issue Number: 5.1

a) As part of its EB-2006-0501 Application Hydro One indicated it would establish a Regulatory Asset Recovery Account with respect to those Regulatory Assets approved as of April 30. 2007. Please indicate the current status of this account and provide a continuity schedule through to December 31, 2008.

Response

The current status of the regulatory recovery for the Market Ready and the Deferred Export Transmission Service Credit costs approved in EB-2006-0501 (effective date of January 1, 2007) is as follows;

Market Ready Costs Continuity Schedule:

In M$	Opening Balance January 1, 2007	Actual LTD December 31, 2007	Actual LTD September 30, 2008	Projected LTD December 31, 2008
Opening Principal	16.4			
Recovery of Principal		(1.2)	(6.6)	(8.2)
Interest Improvement		0.8	1.2	1.3
Net to be Recovered		16.0	11.0	9.4

Deferred Export Transmission Service Credit Continuity Schedule:

In M$	Opening Balance January 1, 2007	Actual LTD December 31, 2007	Actual LTD September 30, 2008	Projected LTD December 31, 2008
Opening Principal	(48.8)			
Recovery of Principal		3.6	19.5	24.5
Interest Improvement		(2.3)	(3.5)	(3.8)
Net to be Recovered		(47.5)	(32.8)	(28.0)

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #63 List 1

Interrogatory

Reference: (i) Exhibit G2/Tab 3/Schedule 2, pages 1-2
(ii) EB-2006-0501 – Exhibit G2/Tab 3/Schedule 2, page 1

Issue Number: 6.2

a) In the current Application there are considerably more (i.e., more than double) Generator Station Connections identified than in the previous application. Are all of the additional stations new stations in-service since the last Application or has there been a change in how stations deemed to be generator station connections are defined?

Response

a) The increase in assets being classified as Generation Station Connections is due to two database clean-up issues and the identification of new "junctions" used to connect Generating Stations to the transmission system. The identification of new junctions is a refinement to our Fixed Asset system that will facilitate future cost assignment for any work done on these assets. The new junction assets identified do not currently have any costs assigned to them and do not impact the allocation process.

Vulnerable Energy ConsumersCoalition (VECC) INTERROGATORY #64 List 1

Interrogatory

Reference: (i) Exhibit G2/Tab 1/Schedule 1
(ii) EB-2006-0501 – Exhibit G2/Tab 1/Schedule 1

Issue Number: 6.2

a) How are the assets classified as "OTHER" in reference (i) functionalized to the rate pools?

b) Are there any transmission lines whose Functional Category has changed since the EB-2006-0501 Application? If yes, please identify the lines and the reason for the change.

Response

a) The costs which have been functionalized as Other and/or Common are allocated to the Network, Line Connection and Transformation Connection rate pools by proration based on the size of these rate pools.

b) There are 56 transmission line segments out of more than 2,200 line segments on the transmission system for which the functionalization has changed in EB-2008-0272 as compared to EB-2006-0501.

The reasons for the functionalization changes are mainly due to line segment reconfigurations, database clean-up or the removal of certain line segments. Line segment reconfiguration includes the adding/removing of customer taps to/from an existing line segment.

Tables 1 and 2 list the EB-2006-0501 line segments which have been changed. Table 1 shows the line segments used in both filings and their old and new functionalization assignments. Table 2 shows the line segments that were renamed as a result of reconfiguration and whose functionalization changed as compared to EB-2006-0501.

Table 1: New Line Segment Rate Pool Assignments

Operating Designation	Section #	EB-2006-0501	EB-2008-0272
A1T	7	LC	OTHER
A1T	15	LC	OTHER
A8M	1	N	DFL
A8M	2	N	DFL
B3N	2	OTHER	N
B3N	3	OTHER	N
B3N	4	OTHER	N
B3N	5	OTHER	N
B4V	2	N	DFL
B4V	3	N	DFL
B4V	4	N	TDF
B8W	5	OTHER	LC
BL104	1	N	OTHER
BSC105	1	N	OTHER
BSC105	2	N	OTHER
C1A	3	N	LC
C2A	3	N	LC
C3A	3	N	LC
C3S	1	DFL	N
D3K	4	TDF	OTHER
H24C	15	LC	OTHER
H26C	15	LC	OTHER
H2JK	11	LC	OTHER
H9A	13	OTHER	N
H9A	16	OTHER	LC
M1R	7	LC	OTHER
M20D	6	TDF	DFL
M20D	9	LC	DFL
M20D	10	LC	DFL
Q26M	4	DFL	OTHER
Q26M	6	DFL	OTHER
Q35M	4	DFL	OTHER
Q35M	7	DFL	OTHER
Q4C	2	OTHER	N
T2R	4	OTHER	LC
T2R	6	OTHER	LC
W71D	4	DFL	TDF
W71D	5	DFL	TDF
X2H	4	N	DFL
X4H	3	N	DFL
29M1	10	LC	database clean up
A5H	12	TDF	database clean up

Operating Designation	Section #	EB-2006-0501	EB-2008-0272
A5H	13	TDF	database clean up
A5H	14	OTHER	database clean up
AT1	2	OTHER	line section removed
B3E	3	OTHER	line section removed
B6M	9	OTHER	line section removed
Q5B	11	LC	line section removed

Table 2: New Line Segment Names and Rate Pool Assignments

Per EB-2006-0501		Re-named per EB-2008-0272			
Operating Designation	**Section #**	**Operating Designation**	**Section #**	**EB-2006-0501**	**EB-2008-0272**
D7G	1	D7F	1	LC	DFL
D7G	2	D7F	2	LC	DFL
D7G	3	D7F	4	LC	DFL
D7G	4	F12C	1	LC	DFL
D7G	17	D7F	3	LC	DFL
D7G	21	D7F	5	LC	DFL
H9A	9	H9A	4	N	LC
L25N	3	V41N	1	DFL	N

Vulnerable Energy ConsumersCoalition (VECC) INTERROGATORY #65 List 1

Interrogatory

Reference: (i) Exhibit G1/Tab 3/Schedule 1, page 4 and Attachment 1
(ii) OEB Staff IR #87
(iii) EB-2006-0501, Exhibit G!/Tab 1/Schedule 1,page 4

Issue Number: 6.1

a) In responding to the OEB Staff IR please indicate whether or not Hydro One Networks considers the current cost allocation practice to be more closely aligned with how the transmission system is used and its cost allocation principles (per reference (iii)).

b) Does "45" represent the total number of transmission customers that are currently not charged for line connection service (reference (i), Attachment 1, page 4). Under the alternative approach would there be any customers who would just pay for Network Service and not be billed for Line Connection service and, if so, please explain the type of supply arrangement that would not attract a Line Connection charge.

c) With respect to the three different configurations discussed on pages 2-3, please confirm that:
   - Page 3 (lines 20-22) describe how the "connection" costs associated with those customers in first category were determined.
   - Page 3 (lines 24-29) describe how the "connection" costs associated with those customers in the second category were determined.
   - How "connection" costs for those customers in the third category were determined.

Response

a) Hydro One considers the current cost allocation practice to be a reasonable balance of the cost allocation principles. Given that under the alternative considered by the study the dollars that shift between pools is not significant, the key issue is whether customers supplied at a Network Station should have to pay Line Connection. It is Hydro One's understanding that the Board has previously ruled that customers owning their own Line Connection facilities to a Network Station should not pay a Line Connection charge, and it appears inconsistent to make customers that own their distribution feeders to a Transformer Station located within a Network Station pay a Line Connection charge.

Additionally, the study alternative redefines a minimal amount of what are currently Network pool assets as Line Connection pool assets. It could be perceived as inconsistent with the principle of cost causality for such minimal use of Line Connection assets to result in the levying of a Line Connection charge that recovers the total cost of all Line Connection facilities. The study alternative also requires numerous interpretative assumptions that complicate the cost allocation process.

b) "45" presents the number of Transmission Delivery Points, not customers, which currently are not levied any Line Connection charges. The "45" delivery points supply 11 Transmission customers, excluding Power Producers.

Under the "Alternative Approach" considered in the study, Power Producers will still be exempt from any Connection charges.

c) For study purposes, the same assumptions were used to derive the average "connection costs" for all three configurations analyzed. The assumptions being:

- Addition/ Modification of isolating devices, that is, breakers, motorized disconnect switch, and/or

- Extension and modification to high-voltage connection point for incorporating the connection at the station and/or

- Protection and Control modifications at the Network Station to incorporate the connection

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #66 List 1

Interrogatory

Reference: (i) Exhibit G2/Tab 5/Schedule 1,.page 1
(ii) Exhibit H1/Tab 5/Schedule 1, page 2
(iii) EB-2006-0501, Exhibit J/Tab 5

Issue Number: 2.2

a) Please provide a schedule setting out the actual monthly revenues received by Hydro One Networks for Export Transmission Service from January 2006 to the most recent month available.

b) Please update the response to VECC IR #126 from EB-2006-0501 to include 2007 and 2008 year to date.

Response

a) Revenues received for export transmission service for the periods January 2006 to September 2008 are as follows:

in K$	**2006**	**2007**	**2008**
Jan	1,380.8	862.6	2,299.2
Feb	1,211.3	1,285.6	1,758.5
Mar	1,288.5	1,022.0	1,899.6
Apr	1,334.8	1,275.8	2,480.4
May	1,272.5	1,215.2	2,876.7
Jun	1,018.4	1,166.7	2,727.1
July	1,068.1	1,428.8	2,585.3
Aug	1,282.4	1,302.7	1,853.0
Sep	916.2	1,054.6	1,430.1
Oct	1,083.5	940.5	
Nov	705.8	1,041.3	
Dec	687.8	1,535.8	
Total	**13,250.1**	**14,131.5**	**19,909.9**

b) Export Transmission Service Revenue Split (Source: IESO)

Year	Wheel Through Transactions	Exports Originating in Ontario
2007	1.0%	99.0%
2008[1]	23.7%	76.3%

[1] Covers the settlement period January 1, 2008 to October 31, 2008.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #67 List 1

Interrogatory

Reference: (i) Exhibit H1/Tab 2/Schedule 1

Issue Number: 7.1

a) With respect to page 2, why is the fact that end-use transmission customers non-coincident peaks are 28% higher than their coincident peak evidence that "increased ability of end-use transmission customers to shift load away from system peak" as opposed just evidence that they don't peak at the same time as the LDCs who (due to the fact they are 90% of demand) set the system peak?

b) With respect to page 3, please provide a schedule that sets out the number of Delivery Points for LDCs, End-Use Customers and Transmission Connected Generators where, for 2009, the Sum of the Higher of Monthly CP or 85% of NCP (7 am to 7 pm) is greater than the Sum of the Average Monthly CP Demand.

Response

a) Hydro One agrees that the difference in non-coincident peaks between the End-Use customers and the LDCs can also be an indication that they do not peak at the same time as the LDCs.

b) Transmission delivery points are billed for Network service on a monthly basis. In each month, the billing demand can be either 85% NCP or CP, whichever is the highest. Analysis was performed per Transmission Delivery Point per month to isolate the instances where the charge determinant was 85% NCP and not CP.

The attached table summarizes the number of billed months for which the delivery points per customer group are charged based on 85% NCP demand.

Customer Group	**Tx Delivery Points**	**Total Billed Months (Tx Del Pts x 12)**	**85% NCP Billed Months**
Directs	91	1,092	461
LDCs	427	5,124	755
Power Producers	77	924	420

<u>Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #68 List 1</u>

Interrogatory

Reference: (i) EB-2006-0501, Exhibit J/Tab 5

Issue Number: 7.1

a) Please update the response to VECC IRs #116 (ii) to include 2007 actual and weather corrected values.

Response

Please see the following table.

Ontario 1-Hour Peak Demand
(MW)

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Actual												
1999	23,150	21,046	20,536	17,990	19,584	22,793	23,433	21,114	21,227	18,620	21,019	22,208
2000	23,301	21,759	20,162	19,265	20,313	21,866	21,616	23,160	23,107	19,259	21,862	23,126
2001	22,432	21,795	21,165	18,856	19,144	23,550	23,966	25,239	21,238	19,591	21,178	21,741
2002	22,191	22,623	21,886	20,386	20,068	23,578	25,226	25,414	25,062	21,216	21,862	23,334
2003	24,158	23,469	23,117	21,010	18,741	24,753	23,175	23,891	20,700	20,408	21,584	22,798
2004	24,937	22,608	21,634	19,911	20,327	23,163	23,976	23,159	21,911	19,829	22,066	24,979
2005	24,362	22,322	22,724	19,343	19,007	26,157	26,160	25,816	23,914	20,752	22,564	23,766
2006	23,052	22,321	21,772	19,582	24,857	23,349	26,092	27,005	19,976	19,590	21,267	22,941
2007	23,537	23,935	22,969	20,016	21,490	25,737	24,561	25,584	24,046	19,233	21,814	22,935
Weather Corrected												
1999	23,031	22,067	20,893	19,132	18,738	21,188	21,623	21,287	20,048	19,212	21,736	22,659
2000	23,209	22,574	20,958	19,280	19,424	21,833	22,435	22,039	20,524	19,707	21,756	22,690
2001	23,595	23,178	21,307	18,906	18,926	22,097	22,619	22,351	20,688	19,882	22,006	23,113
2002	23,369	23,374	21,556	19,304	18,966	22,376	22,755	22,570	21,222	20,312	22,444	23,466
2003	23,612	23,392	21,807	19,758	19,233	22,367	22,955	22,842	21,294	20,062	22,387	23,629
2004	23,676	23,560	22,128	20,016	19,373	22,658	23,187	23,008	21,524	20,199	22,822	23,824
2005	23,877	23,685	22,187	20,209	19,407	22,951	23,476	23,395	21,746	20,118	22,276	23,632
2006	23,899	23,218	22,006	19,966	19,351	22,826	23,119	22,927	20,510	19,816	21,746	23,160
2007	23,229	22,715	20,536	19,539	18,656	22,022	22,369	22,401	20,543	19,755	22,459	23,487

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #69 List 1

Interrogatory

Reference: Exhibit H1/Tab 4/Schedule 1, page 2

Issue Number: 7.1

a) Has Hydro One Networks undertaken any analysis that supports the continuation of the $5,200 per meter exit fee? If yes please provide. If no, why is the current value viewed as appropriate?

Response

a) No, Hydro One has not undertaken any new analysis to support the continuation of the $5,200 per meter exit fee as the number of instances where the charge would be applicable is small and dropping. As noted in Exhibit H1, Tab 4, Schedule 1, page 2, Table 1, by 2010 it is expected that only 163 meter points will remain in the pool that would be subject to the exit fee when they leave the pool.

Power Workers Union (PWU) INTERROGATORY #1 List 1

Interrogatory

GENERAL

Reference: Exhibit A/Tab 12/Schedule 1/Page 1 (DBRS Rating Report)

Preamble: In the cited reference, included in the challenges of Hydro One considered by the rating agency (DBRS) are substantial capital expenditure programs, significant external financing requirements and the lack of access to equity capital market.

Question:

a) Does Hydro One expect these challenges to increase in the context of the recent economic down turn and crunch in the credit market?
b) If response to (a) is 'yes', is Hydro One taking any proactive actions and does it have plans that will help it deal with economic events outside of its control that could potentially result in significant variance from forecast revenue and planned work programs?
c) Please provide recent updates on Hydro One's rating produced by any of the rating agencies.

Response

a), b) Hydro One expects that the challenges cited in the DBRS Rating Report to continue or somewhat increase in the context of the economic downturn. For example the "volume of electricity sold" could decrease. Please refer to Exhibit I, Tab1, Schedule 10 for a further response to this question.

c) Attached is the credit rating report from Standard and Poor's dated November 17, 2008.

Filed: December 23, 2008
EB-2008-0272
Exhibit I-7-1
Attachment 1

STANDARD
&POOR'S

COMMENTARY
REPORT

Hydro One Inc.

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Publication Date
Nov. 17, 2008

Rationale

The ratings on Hydro One Inc., a large, regulated transmission and local electricity distribution company (LDC) in the Province of Ontario (AA/Positive/A-1+), reflect the company's low-risk monopoly electricity transmission and distribution networks, secure and relatively predictable regulated cash flows, and the support of its owner, the province. In Standard & Poor's Ratings Services' opinion, offsetting its excellent business risk profile is an intermediate financial risk profile that will face the challenge of a large capital expenditure program in the next several years. The company had C$5.6 billion in debt outstanding as of Sept. 30, 2008.

Hydro One's monopoly position, the business' asset-intensive nature, and regulatory oversight limit competitive risk. It owns and operates more than 96% of the province's transmission network as measured by revenue, and its distribution network service territory covers about 75% of the province. Both the electricity transmission and distribution business carry relatively low operating risk, and exhibit average operational efficiency and reliability. We view the transmission operations as lower risk than distribution.

The Ontario Energy Board's (OEB) regulatory framework supports Hydro One's cash flow stability. The framework allows for the recovery of prudent transmission and distribution costs and the opportunity to earn a modest return. Regulatory cost recovery is generally predictable and timeliness is improving. Furthermore, in the current environment, the LDC's exposure to commodity risk is limited and the transmission provider has none. Although the LDC must bill electricity customers for the commodity delivered, the cost is a flow-through. The company has no obligation to ensure an adequate supply of electricity and is not burdened with the procurement process or power purchase agreements. Net distribution and transmission revenues are subject to modest volumetric risk due to weather. There is no near-term expectation of energy policy or electricity market framework initiatives that would affect the regulatory environment or the company's credit quality.

Hydro One has an intermediate financial risk profile that we believe could weaken during the buildout of the regulated asset base in the next two-to-three years. The extent of the temporary decline in the utility's cash flow strength will depend largely on timing of regulatory approvals and execution of planned capital expenditures, the impact of weather on revenue net of commodity costs, and the company's ability to find operating efficiencies sufficient to offset the OEB's performance-based pressures on rates. Adjusted funds from operation (AFFO) interest coverage was 3.7x as of Dec. 31, 2007 and 3.9x on a rolling 12-month basis as of Sept. 30, 2008. All else being equal, interest coverage could fall to closer to 3x due to delayed cash recovery from assets under construction without impinging on the rating, largely because of the business' regulated monopoly nature and Hydro One's government shareholder relationship. AFFO-to-total debt could decline to about 12% compared with the 2007 level of 14%. As of Sept. 30, it remained at about 14% on a rolling 12-month basis.

Hydro One's leverage, as measured by adjusted total debt-to-total capital, is also likely to temporarily creep back up to the historical level of about 64%, compared with 58% in 2007. Although partially funded from internal sources (about 50%), we believe capital spending during the next few years will be a drain on the company's cash flow, reducing financial flexibility and pressuring cash flow coverage. The utility budgeted C$1.4 billion in capital expenditure for 2008 but had only spent C$835 million as of Sept. 30 (62% of plan). The company estimates its 2009 capital program at more than C$1.5 billion. For several years, capital spending will be higher than the historical average of about C$700 million in the 2002-2006 period.

The transmission system requires upgrades and expansion to accommodate new and retiring generation, increased imports and exports, and modest growth in domestic demand. The 2008 and 2009 capital programs also include part of the estimated remaining C$670 million investment that Hydro One will make in smart meters for all distribution customers under a provincial directive by 2010.

The province's ownership of Hydro One enhances the utility's credit quality. Although Ontario does not formally guarantee the company's debt obligations, Hydro One's strategic nature within the provincial economy and the government's demonstrated willingness to assist the business (with liquidity support) under extraordinary circumstances in the past bode well for similar future support.

Short-term credit factors

The short-term rating on Hydro One is 'A-1'. Unused and committed bank lines, together with strong cash flow from operations and access to debt capital markets, provide Hydro One with sufficient liquidity and the financial flexibility to meet the company's estimated capital expenditure of more than C$1.5 billion in 2009, annual dividend payments of C$250 million-C$290 million, and C$400 million of debt maturing in February 2009. Furthermore, the company remains well within its banking covenant of total debt-to-total capital of 75% and has no material adverse change clauses that could trigger a default.

To support liquidity, the company can draw on:

- A committed C$1 billion bank line (maturing August 2010), of which C$840 remained available to support C$95 million in letters of credit outstanding as of Sept. 30. The bank line is used for general corporate purposes and to support Hydro One's C$1 billion Canadian commercial paper program, of which C$160 million was outstanding at third-quarter end;

- Annual regulated cash flows, as represented by unadjusted FFO, estimated at about C$900 million in 2008 and 2009;
- A medium-term note shelf program, maturing in July 2009, with C$1.15 billion remaining capacity as of Nov. 14, 2008;
- Discretionary capital expenditure estimated at more than C$200 million in 2008 and in 2009.

The company provides the Independent Electricity System Operator (IESO) with C$325 million in parental guarantees in lieu of prudential support. If all credit ratings on Hydro One were to fall below 'AA-', the IESO's prudential requirements would likely increase.

Outlook

The stable outlook reflects Hydro One's excellent business risk profile, which mitigates financial pressures of a larger-than-normal capital spending program. An adverse regulatory ruling or market restructuring (such as the assumption of the obligation to supply) could lead to a negative rating action. An upgrade is unlikely without the assurance of a much stronger balance sheet, and deeper cash flow-interest and -debt coverage. A significant change in the relationship with the government shareholder could move the rating up or down, but likely not more than a notch given the company's underlying credit strength.

Power Workers Union (PWU) INTERROGATORY #2 List 1

Interrogatory

OM&A

Issue 3.1

Are the proposed spending levels for Sustaining, Development and Operations OM&A in 2009 and 2010 appropriate, including consideration of factors such as of system reliability and asset condition?

Reference: a) Exhibit A/Tab 15/Schedule 1/ Figure 7
b) Exhibit A/Tab 15/Schedule 1/ Page 12

Preamble: Ref (a) indicates an increase in the System Unavailability measure in 2007 after a decline for the period between 2003 and 2006. Ref (b) indicates that this was due to an increase in planned line outage work compared to previous years.

Question:

a) Please explain the drivers for the increase in planned line outage work in 2007 and why System Unavailability, which is also affected by unplanned work, was lower in 2006 despite the ice storm in that year?
b) What is Hydro One's forecast for unsupplied energy due to planned work beyond 2007?
c) Ref (b) indicates that the increase in System Unavailability was not detrimental to the delivery performance to load customers. How does Hydro One ensure increases in System Unavailability do not adversely impact on delivery to load customers?

Response

a) The main driver behind the increase in planned line outage work in 2007 is the number of upgrade projects. These projects included cable diversion work on the several 115kV cable circuits in the city of Toronto and reconductoring of a 115kV circuit in the Ottawa area to support work on a new interconnection with Hydro-Quebec (TransEnergie). Due to their large scopes of work, these projects required extensive circuit outage time to be completed. This resulted in a greater duration of circuit outage time than work in previous years. Note that customer supply was maintained during these extended periods of equipment unavailability. Relatively high System Unavailability due to outages of this magnitude is not expected to occur in 2009 and 2010. However, this measure is expected to be higher than 2005 and 2006 levels in future years due to increasing work programs.

The System Unavailability measure as presented in the referenced exhibit includes planned and unplanned outage events. Typically, forced outage events contribute much less to this measure than planned outage events. A winter storm occurred during February 4-6, 2006 in Southwestern Ontario. Although, the storm resulted in numerous outages on the Hydro One transmission system, the effect of this storm caused an impact of less than 1% on the System Unavailability measure for that year.

b) Unsupplied Energy due to planned work is projected to be approximately 1 system minute by year-end 2008. Typically, planned work constitutes less than 15% of the total Unsupplied Energy. The impact of planned work beyond 2008 is not known at this time. Planned interruptions usually affect this measure to a minor extent due to the actions taken by Hydro One to mitigate supply to load customers. Therefore, this measure it is not forecast into future years.

c) As discussed earlier in part a) above, planned outages on major circuit equipment directly affect System Unavailability. However, due to the design and configuration of the network, not all equipment outages result in load interruptions to customers. Hydro One takes steps to mitigate the impact of planned outage work on delivery to load customers through various ways including communication with customers in advance of the planned outage, scheduling planned outages during off-peak hours, performing live line work where feasible, and executing load transfers where possible.

Power Workers Union (PWU) INTERROGATORY #3 List 1

Interrogatory

OM&A

Issue 3.1

Are the proposed spending levels for Sustaining, Development and Operations OM&A in 2009 and 2010 appropriate, including consideration of factors such as of system reliability and asset condition?

PWU Interrogatory 3

Reference: Exhibit A/Tab 15/Schedule 1/Page 13/Table 3

Preamble: The SGS 2008 Study in the cited reference indicates that for 230kV and above systems, Hydro One is in either first or second quartile depending on the metric used, and for systems in the 100-161kV range, Hydro One is in the third or fourth quartile. Hydro One states that the results for the 115 kV system are expected due to the rural nature of the system and the longer radial circuits than most of its comparator transmission companies.

Question:
Which specific work/investment programs in this application does Hydro One propose and expect to improve the reliability performance of the 115kV system?

Response

Hydro One takes actions to improve reliability performance of its system as part of a number of programs, as discussed in the response to Interrogatory Exhibit I, Tab 1, Schedule 30. Investments funded by the Performance Enhancement program discussed in Exhibit D1, Tab 3, Schedule 3, pages 27 to 28 also contribute to improving reliability and include some of the following specific work:

- Installation of lightning arrestors on circuits that are experiencing a high number of lightning outages.
- In locations where conductors are prone to galloping, Hydro One would install anti-galloping devices to prevent conductors from clashing.
- Installation of switches to facilitate sectionalizing thereby reducing the number of affected customers and restoration time.
- Installation of fault locating devices to identify the fault location and reduce restoration time.

Power Workers Union (PWU) INTERROGATORY #4 List 1

Interrogatory

OM&A

Issue 3.3
Are the compensation levels proposed for 2009 and 2010 appropriate?

Reference: a) Exhibit C1/Tab 3/Schedule 2/Page 1
b) Board staff Question 41

Preamble: Board Staff has requested Hydro One to provide comparison of Hydro One's compensation, wages and benefits with other Ontario Hydro successor companies.

Question:
Please include compensation, wages and benefits at Bruce Power in your comparison.

Response

The response to Exhibit I Tab 1 Schedule 41 includes Bruce Power comparisons.

Power Workers Union (PWU) INTERROGATORY #5 List 1

Interrogatory

OM&A

Issue 3.3
Are the compensation levels proposed for 2009 and 2010 appropriate?

Reference: a) Exhibit A/Tab 16/Schedule 2/Attachment 1/Pages 1-2
b) Exhibit A/Tab 16/Schedule 2/Attachment 1/Table 7

Preamble: Ref (a) states "On an overall weighted average basis for the positions we reviewed, Hydro One is approximately 17% above the market P50. This positioning appears to be driven by a combination of competitive base salaries, especially for the most highly skilled Power Workers' Union ("PWU") positions, and legacy collective agreement wages, pension and benefits programs."
Ref (b) presents benchmarking results for the PWU represented positions wherein market results are weighted by organization, i.e., for each participating company one average value per position is determined.

Question:
One major factor influencing the skill level of workers referenced in Ref (a) is progression, i.e., the duration and steps required to qualify for a position. Does the compensation cost benchmarking analysis consider Hydro One's progression for a position such as Regional Maintainer –Lines (Supervisor) with the progression required in the comparator organizations for the same position? For the purpose of your response, assume an illustrative scenario in which a Supervisor at Hydro One is paid a comparable base salary as another employee in one of the comparator organizations and compare the progression requirements.

Response

The benchmarking analysis does not consider progression for a certain classification. Since individual respondent data is not available to Hydro One, it is not possible to make a comparison of progression steps to comparable organizations.

Power Workers Union (PWU) INTERROGATORY #6 List 1

Interrogatory

OM&A

Issue 3.3
Are the compensation levels proposed for 2009 and 2010 appropriate?

Reference: Exhibit A/Tab 16/Schedule 2/Attachment 1

Question:
In the opinion of the consultants that conducted the Compensation Cost Benchmarking Study, what are the shortcomings of the study including data that was available for the study, the analytical methods/approaches used in the study, and the findings of the study?

Response

Please see the attached letter from Mercer Consulting.

Filed: December 23,2008
EB-2008-0272
Exhibit I-7-6
Attachment

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15 December 2008

Mr. Glen MacDonald
Senior Advisor - Regulatory Affairs
Hydro One Networks, Inc.
8th Floor, South Tower
483 Bay Street
Toronto, ON M5G 2P5

Private & Confidential

Subject: Question Regarding Possible Study Limits

Dear Glen,

As requested as part of case EB2008-0272 currently before the Ontario Energy Board ("OEB"), we have reviewed the Power Workers' Union ("PWU") Interrogatory Question #6 and the question from Energy Probe regarding the Total Compensation Cost Study ("the Study") that Mercer recently completed on behalf of Hydro One. Specifically, we understand the question from the PWU is as follows:

> *"In the opinion of the consultants that conducted the Compensation Cost Benchmarking Study, what are the shortcomings of the study including data that was available for the study, the analytical methods/ approaches used in the study, and the findings of the study?"*

To provide a framework to respond to the specific points requested in the question above, we have organized our response into the following three categories. Specifically:

1. **Data Availability** - Potential issues related to data availability;
2. **Analytical Methods** - Potential issues related to analytical methods/approaches; and
3. **Findings** - Potential issues related to the findings of the study.

Summarized below are our responses to the specific points requested in the question above. Specifically:

1. Data Availability
Given the relatively small size of the Canadian electrical utility market and the unique structure of each utility organization, ensuring that all relevant peers participated in the Study was essential to the Study's success.

To ensure that the appropriate peer organizations across Canada did participate, Mercer worked with Hydro One to contact each desired Study participant to ask for their co-operation and participation in the study.

With the support of Hydro One, all utility peer organizations did participate in the Study.

2. Analytical Methods
The objective of the Study was to provide independent benchmarking information using generally accepted benchmarking approaches. As a result, we applied our standard benchmarking approach to collect, tabulate and analyze the results.

As with any compensation benchmarking study, the analysis and data is limited to the extent that each participating organization provided complete and accurate information on compensation levels.

Based on our review of the raw data submissions, we believe that the data provided by participants to be complete and consistent with typical compensation benchmarking projects.

3. Findings
As noted above and in the report findings, the Study reflected 30 benchmark positions and was designed to be a sampling of the most highly populated positions at Hydro One to ensure that no one position biased the results.

Although we did not do any analysis of Hydro One's remaining employee population beyond the roles in the study, the intention of the sample that was chosen was to include job classes with large numbers of incumbents (i.e., more than 10 incumbents) to provide a perspective on "total compensation costs" at Hydro One. In addition, to ensure representation from all of Hydro One's major operating units and departments, some roles with less than 10 incumbents were also included in the Study.

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GUY CARPENTER OLIVER WYMAN

We understand that there are approximately 700 position classes that were not covered by the study as they, in general, have fewer than 10 incumbents. As a result, it is possible that within these position classes there may be compensation levels that are higher or lower than the overall 17% above median conclusion. Given the relatively small number of incumbents per position, however, they are likely less material from a "total cost" perspective than the roles that were part of the Study.

As the Study followed our generally accepted benchmarking principles and reflected a significant portion of Hydro One’s population, we do not believe that any data availability or analytical method issues would materially alter our overall results and conclusions.

Glen, I trust this letter provides the information you require. If you have any further questions, please do not hesitate to give me a call.

Sincerely,

Iain Morris
National Partner

Copy:
Mark MacCharles, Mercer

Energy Probe INTERROGATORY #1 List 1

Interrogatory

Ref: Exhibit A, Tab 13, Schedule 2

This reference describes the applicant's changes to policies. Please provide copies of the following policies:

i) First Nations and Métis Policy
ii) Corporate Procedure for Retention of Consultants
iii) Corporate Charge Card Procedure
iv) Employee Business Expense Policy & Procedure
v) Employee Travel and Accommodation Policy
vi) Major Fixed Asset Retirement/Surplus Reporting Procedures
vii) Purchase of Low Value Non ACL External Contractors Services & Materials (Local Purchase Contract)

Response

Please see attachments:

i) Attachment 1 - First Nations and Métis Policy
ii) Attachment 2 - Corporate Procedure for Retention of Consultants
iii) Attachment 3 - Corporate Charge Card Procedure
iv) Attachment 4 - Employee Business Expense Policy & Procedure
v) Attachment 5 - Employee Travel and Accommodation Policy
vi) Attachment 6 - Major Fixed Asset Retirement/Surplus Reporting Procedures
vii) Attachment 7 - Purchase of Low Value Non ACL External Contractors Services & Materials (Local Purchase Contract)

Document Number: **SP 0837 R0**

Document Name: **First Nations & Métis Relations Policy**

Issue Date: **September 2008**

The requirements of this document are mandatory.

Purpose

This document provides Hydro One employees with guidance on their relationships with First Nations & Métis peoples.

Revision

Information contained in the policy, approved in December 2007, is now contained in this document.

Contents

1.0 Scope

This policy applies to Hydro One Inc. and its subsidiaries.

2.0 Statement of Policy

Hydro One is committed to developing and maintaining relationships with First Nations & Métis peoples that demonstrate mutual respect for one another.

Hydro One owns assets on reserve lands and within the traditional territories of First Nations & Métis peoples. Hydro One recognizes that First Nations & Métis peoples and their lands are unique in Canada, with distinct legal, historical and cultural significance.

Hydro One is committed to working with First Nations & Métis peoples in a spirit of cooperation and shared responsibility. Forging relationships with First Nations & Métis communities based upon trust, confidence, and accountability is vital to achieving our corporate objectives.

This First Nations & Métis Relations Policy enhances and complements other corporate policies and will guide Hydro One in its relationships with First Nations & Métis peoples.

3.0 Objectives

Hydro One's First Nations & Métis Relations objectives are to:

- Where appropriate, undertake together with the Crown, consultation with First Nations & Métis peoples and communities in the early stages of, and throughout, projects or other activities that may impact upon them.
- Continue to build positive, mutually beneficial relationships with First Nations & Métis communities.
- Help Hydro One employees to understand the unique legal, historical and cultural significance of First Nations & Métis peoples, for the purpose of promoting effective relationships with First Nations & Métis customers and communities.
- Promote business and workforce development for First Nations & Métis peoples.

4.0 Principles

The principles outlined below have been developed to instruct in the application of the First Nations & Métis Relations Policy, such that managers and employees of Hydro One can transform the First Nations & Métis Relations Policy into action.

4.1 Communication

- Hydro One communications and public education efforts will take into account the situation and interests of First Nations & Métis customers and communities.
- Hydro One will continue to work with First Nations & Métis employees, communities and organizations to share information, concerns, and ideas of mutual interest to promote effective relations.
- Hydro One endeavors to make First Nations & Métis customers, communities and organizations aware of its policies, practices, and procedures.
- Hydro One will consult and cooperate with provincial and federal agencies on matters of mutual interest and concern relating to First Nations & Métis peoples as may be appropriate.

4.2 Hydro One Operations

4.2.1 Customer Service

- Hydro One will carry out all its business activities with First Nations & Métis peoples and communities in a manner that is respectful, responsive, and timely.
- Hydro One strives for excellence in providing customer service to First Nations & Métis peoples and communities in Ontario and works to anticipate their needs.
- Hydro One will ensure that information and training is available to employees to guide and support them in their interactions with First Nations & Métis communities and customers.

4.2.2 Negotiation

- Hydro One favours resolving matters with First Nations & Métis peoples in a non-adversarial manner.
- Hydro One negotiates in good faith and in a timely manner, to find solutions that are of benefit to both the First Nations & Métis community and to Hydro One, and that will build the foundation for successful future relationships.
- Hydro One is committed to seeking resolution of transmission and distribution line tenancy issues, past grievances, and other issues with First Nations & Métis communities.
- Hydro One negotiates compensation for its transmission line permits on the basis of fair market value, and in a fair and consistent manner.

4.2.3 Environmental Impacts

- Hydro One considers environmental protection to be one of the keys to the success of the company. We recognize and respect First Nations & Métis peoples' unique knowledge of the natural environment and their historical attachment to the land.
- Hydro One seeks to minimize and mitigate environmental impacts of Hydro One operations on First Nations & Métis people, communities and lands.

4.3 Community Economic Development and Capacity Building

- Hydro One supports collaboration with First Nations & Métis businesses and communities to further First Nations & Métis participation in the electricity sector and related economic opportunities.
- Hydro One supports procurement opportunities for qualified First Nations & Métis businesses Hydro One encourages the development and viability of First Nations & Métis contractors who can provide goods and services to the company through identifying contracting opportunities, conducting workshops and the promotion of business networking.
- Hydro One supports community initiatives, and cultural activities through its corporate citizenship programs.

4.4 Employment and Education

- Hydro One supports diversity and is committed to increasing the representation of First Nations & Métis people in all levels of its workforce.
- Hydro One will cooperate with First Nations & Métis peoples to develop initiatives that support First Nations & Métis peoples in gaining the knowledge and skills that will prepare them for employment with Hydro One.
- Hydro One provides training to its employees to help them to understand the unique legal, historical and cultural significance of First Nations & Métis peoples, for the purpose of promoting effective relationships with First Nations & Métis customers and communities.

5.0 Accountability

This policy applies to Hydro One Inc. and its subsidiaries. All employees whose responsibilities include relationships with First Nations & Métis people or the development of programs and policies affecting First Nations & Métis people will be guided by this policy. In order to ensure that this policy becomes operational, strategies, procedures and tools will be developed to guide and support managers and employees in their relationships with First Nations & Métis people.

Appendix A: Document Management

Owner/Functional Responsibility	Corporate and Regulatory Affairs - First Nations & Métis Relations
Approval Date	December 2007
Approval Required By	Executive Committee, Human Resources & Public Policy Committee of the Board of Directors
Effective Date	December 2007
Document Last Reviewed	September 2008

HODS

Document Number: **SP 0709 R0**

Document Name: **Corporate Procedure for Retention of Consultants**

Issue Date: **August 2008**

When in printed form, this document is uncontrolled.
It is the user's responsibility to verify that this copy matches the document on the Hods website.

The requirements of this document are mandatory.

Purpose

This procedure is meant to assist and guide end-users, contract managers and project sponsors ("Requisitioners") in the process of planning for, evaluating, selecting and managing Consultants consistent with the Corporate Policy on Consultants and Procurement Policy and Principles. The application of this procedure will be to all Consultant requirements as defined in the Corporate Policy on Consultants.

Revision

Information contained in the policy, approved in March 2005 by the Executive Committee, is now contained in this document.

Contents

1.0 Summary

This procedure is meant to assist and guide end-users, contract managers and project sponsors ("Requisitioners") in the process of planning for, evaluating, selecting and managing Consultants consistent with the Corporate Policy on Consultants and Procurement Policy and Principles. The application of this procedure will be to all Consultant requirements as defined in the Corporate Policy on Consultants.

This is a high level process. Inergi SMS/Hydro One Supply Chain trained purchasing staff ("Purchasing Individuals") possess the expertise to guide Requisitioners through the process of retaining Consultants and have access to specific guidelines (Buying Guide Manual/SMS Operations Manual), templates and resources to enable them to conduct the competitive process. Purchasing Individuals will ensure the Corporation's purchasing power is leveraged to maximize opportunities for rebates and discounts.

2.0 Governing Principles

The process for securing resources involving Employee/employer relationships (regular staff, temporary and permanent) is not covered by this procedure.

Approval of a Consultant engagement requires a specific requisitioning authority element under the Organizational Authority Register (OAR).

If a contract involves both consulting services and other types of services, then this policy applies as though the primary objective of the contract is the purchase of consulting services alone.

Hydro One will ensure that no Consultant has an unfair advantage over its competitors through pre-proposal activities. The successful proponent of the work shall not have an unfair advantage in obtaining subsequent work by virtue of it having completed the awarded work.

The Full Life Cycle of retaining Consultants consists of five major steps:

1. Planning and Need Definition
2. Selecting Consultants to be Invited to Submit a Proposal
3. Request for Proposals (RFP)
4. Contracting
5. Managing the Contract

Hydro One will:

- Disclose in the RFP situations where the consulting service relates to a similar or project specific service previously performed by a Consultant competing for the work.
- Involve Supply Chain in the placement of all Consultant contracts.
- Issue Formal Purchase Orders for all Consulting engagements and payment will be based on invoices submitted against established Purchase Orders (see Appendix E).

- Ensure required Security Checks are performed prior to retaining a Consultant, and all Consultants retained will have received "clearance" (see Appendix G).

Not reimburse Consultant fees and expenses (see Appendix D) using a Corporate Charge Card or Corporate Charge Card Cheques.

3.0 Scope

This procedure applies to all staff in the Corporation involved in any aspect of retaining Consultants. The application of this procedure provides guidelines that assist Requisitioners and Purchasing Individuals in retaining Consultants.

Hydro One Supply Chain is responsible for content, revisions and support of this procedure.

The responsibility for compliance and adherence with this procedure rests with each Line of Business. This includes, but is not limited to, the completion, forwarding and monitoring of all business cases, performance and deliverable documentation and information. Unless explicitly noted, the specific format for this documentation is left up to the judgment of the Requisitioner.

4.0 Application Rules

4.1 Planning and Need Definition

The Planning and Need Definition step is the primary responsibility of the *Requisitioner* who will include support from various business units as required i.e. Human Resources, Finance, Inergi SMS, Supply Chain.

All options to perform the work internally are to be exhausted prior to proceeding ensuring all Purchased Services Agreement (PSA) and the Ontario Labour Relations Act (OLRA) requirements have been met.

All Consultant requirements include a process to ensure that the supplier will not be deemed an Employee of Hydro One. Each individual requirement must be assessed to determine the most appropriate means of securing or contracting for Consultant services. Reference Appendix A and Appendix B. They will guide *Requisitioners* through the decision analysis process resulting in one of two determinations:

1. The individual is deemed to be an "Employee" as defined in Appendix B
2. The individual is deemed to be a "Consultant" as defined in Appendix B

When the individual is deemed to be an Employee, Hydro One will make a secondary determination in accordance with Appendix A that will result in the majority of instances in the individual being hired as a temporary employee reimbursed through Hydro One's payroll system. Notwithstanding, in some instances the individual may be engaged as a Consultant through an agency that does comply with CCRA requirements.

All other individuals must meet the CCRA test as being a Consultant (see Appendix B). If the individual and the working relationship that will be created between that person and Hydro One do not meet the CCRA tests, and he/she will not agree to be hired as a temporary employee or through an agency that does meet CCRA requirements, the individual shall not be retained and other options must be reconsidered.

The distinction between an Employee and a Consultant services engagement is important under tax laws because an employer must withhold statutory deductions (CPP, EI, income tax) from an Employee but not from an individual providing Consultant services. If an individual is misclassified as a provider of Consultant services, Hydro One may be liable for imposed fines and penalties. If the employer directs the individual throughout the term of the agreement, an *employer/employee relationship* is created. This is the key (but not the only) criteria that common law will consider when distinguishing a Consultant engagement from contract Employee engagement.

4.2 Selecting Consultants to be Invited to Submit a Proposal

List of Consultants will be jointly developed by the *Purchasing Individual* and the *Requisitioner*. Vendor names of most qualified will be acquired through recommendations from internal sources, industry contacts, market analysis and/or through a publicly advertised process including Request for Expression of Interest (RFI), Request for Pre-qualification (RFPQ) or Request for Proposal (RFP).

Where the value is less than $5 million, and if a publicly advertised RFP, RFEI or RFPQ process is not utilized, *Purchasing Individuals* will assist *Requisitioners* in conducting a market analysis. A manageable number of proponents are selected based on the market intelligence gained which will provide known competence, knowledge, qualifications and experience of the "market players". The market analysis and rationale for selecting invitees is documented and retained in the appropriate procurement file. This provides a clear audit trail for subsequent inquiries.

Unless the requirement is of a sensitive or confidential nature, all requirements for Consultants estimated at $5 Million dollars will be publicly advertised either as a RFI, RFPQ or RFP and regardless of the value, will be posted on the Hydro One Networks Inc. external Tenders website.

Where the requirement is greater than $50,000 only one Consultant has the required expertise, justification for the single source must be documented by the *Requisitioner* and approved by the Line of Business and Hydro One Manager, Supply Chain. The Template/Form is available on the SMS website. Such requirements are not advertised or posted on the external website or in newspapers.

4.3 Request for Proposals (RFP)

RFP's are utilized as the means of soliciting competitive submissions for Consulting Services. *Purchasing Individuals* must be engaged in the competitive process, where the value of the requirement is greater than $50k. The compilation of the documentation and processes leading to a contract are generally a joint effort between the *Requisitioner* and the *Purchasing Individual*.

The *Purchasing Individual* will be the single point of contact for vendors while the competitive process is conducted.

Consideration of subsequent phases, implementations, increased scope etc. must be considered as part of the go-to-market strategy.

The RFP will disclose situations where the consulting service relates to a similar or project specific service previously performed by a particular Consultant and will disclose if the intent is to award the contract to the Consultant who previously performed the service unless a better offer is submitted.

High-level RFP process steps and primary responsibility:

- Create scope of work/terms of reference document: *Requisitioner*
- Determine commercial terms and conditions considering: pricing, intellectual property, payment terms, termination, dispute resolution, Canada Customs and Revenue Agency (CCRA), Workplace Safety and Insurance Board (WSIB), Freedom of Information Act (FOIA), Personal Information Protection and Electronic Document Act (PIPEDA), insurance, Workplace Human Rights and Anti-Harassment Policy & Procedure, Code of Business Conduct, confidentiality, re-employment of former employees, site access and security check requirements etc.: *Purchasing Individual* in consultation with *Requisitioner*
- Determined by the nature of the requirement, Confidentiality/Non-Disclosure Agreements may need to be executed <u>prior</u> to RFP being released: *Purchasing Individual*
- Develop selection criteria and scorecard (prior to release of RFP): *Purchasing Individual and Requisitioner*
- Develop Format for Submission: *Purchasing Individual*
- Solicit Proposals: *Purchasing Individual*
- Evaluate submissions: *Purchasing Individual and Requisitioner*

Where the value is <u>less than $50k</u> the Requisitioner may, at its sole discretion, solicit proposals directly from vendors, be the point of contact for the vendors, and/or single source the requirement without the requirement for Single Source approval from Manager, Supply Chain or the involvement of the Purchasing Individual. Upon receipt and acceptance of the proposal(s), the Requisitioner shall forward a duly approved Material Request for processing by a Purchasing Individual. The Purchasing Individual will finalize the contract/Purchase Order and make the award to the Consultant.

4.4 Contracting

<u>4.4.1 Selection Process - Evaluating Submissions</u>

The selection process will be conducted jointly by the *Requisitioner* and *Purchasing Individual*. Evaluation matrix (scorecard) and results of the evaluation process will be documented and kept for reference in the Purchase Order file. The results of the evaluation are to be the basis for selecting a particular Consultant. Having a cross-functional team involved with the evaluation process allows a balanced appraisal of Consultants. Each team member individually evaluates the submissions based on the established scorecard. The team lead compiles the scores and establishes the "winner" based on the average of the scoring. Submissions not meeting the "Must" criteria detailed in the RFP will not be scored or considered for award. Re-employment of former employees must be considered in accordance with Appendix C.

4.4.2 Establishing the Contract

No commitment can be made to the Consultant until purchase authority (distinct from requisitioning authority) is obtained in accordance with the OAR. The Organizational Authorities for Consulting requirements for Hydro One business units are contained on the Finance web site. Any reimbursable expenses are to be funded and approved for at both levels of authority (Purchasing and Requisitioning).

Any commitment (purchase order/contract) to an external vendor must be made by a Purchasing Individual. Any consideration for increased scope or subsequent phases are to be detailed in the approval documentation.

An approved Business Case is required for all Consultant engagements $50,000 or greater prior to a commitment being made to the successful Consultant.

The business case supporting rationale will consider the following:

- the use of existing permanent staff in lieu of a Consultant
- the use of temporary staff in lieu of a Consultant
- expectation that the traditional relationship of employer and employee will not exist in the engagement (see Appendix B)
- appropriateness of using a Consultant for the specific scope of work
- knowledge/skills requirements and transfer expectations
- estimated cost and availability of approved budget to cover both time and expense charges
- ability to meet timetable and key milestones
- compliance with policy on Re-employment of Former Employees (see Appendix C)
- expectation that no conflict of interest issues will arise
- expectation that Hydro One's Code of Business Conduct will be adhered to by both Hydro One and the Consultant
- confirmation that no Consultant had an unfair advantage through pre-proposal activities.

The Business Case shall be provided to the Purchasing Individual to be kept in the appropriate procurement file.

A formal Purchase Order in PassPort will be established for all Consultant requirements. The value of the Purchase Order shall not exceed the value of the Material Request and shall be in accordance with the contract terms and conditions.

4.4.3 Method of Payment, Payment Terms and Expenses

The **Corporate Charge Card must not** be used for the payment of Consulting Services and/or reimbursable expenses.

Reimbursable expenses shall be in accordance with Appendix D. Payment terms are to be appropriately structured to manage the risk associated with the value of work received. Structured payment schedules by deliverables retaining a portion for payment on completion and acceptance of the work or full payment on completion and acceptance of the work will assist in the management of this risk. Self-employed Consultants will be allowed to submit bi-weekly invoices for payment within 15 days. All other Consultants will submit invoices in accordance with the contract terms.

<u>4.4.4 Disclosure of Award Information and Debriefing Sessions</u>

Where the value of the requirement is in excess of $100,000 and after award and acceptance of the contract by the successful proponent, Purchasing Individuals will provide a letter informing the unsuccessful proponents of the successful vendor's name. The value of the award will not be disclosed.

Where the value of the requirement is less than $100,000, the successful proponent's name will be disclosed only after award and acceptance and upon request to the Purchasing Individual. This can be done verbally. The value of the award will not be disclosed.

Upon request from unsuccessful proponents, *Requisitioners* and *Purchasing Individuals* will jointly provide debriefs. By providing feedback to the Consultants of reasons for not being selected, it helps to improve quality of subsequent offers. It also offers the supply community an opportunity to be assured of Hydro One's fair, consistent and transparent process for evaluating submissions.

4.5 Managing the Contract: Requisitioner

Managing the contract shall allow:

- Effective management of Consultant contribution
- Reduction in; costs, opportunities for fraud, risk of misuse of Consultants
- Effective audit procedure
- Improved quality of Hydro One's skills sets
- Maximum benefit derived from deliverables

The above is accomplished by:

<u>4.5.1 Requisitioners being responsible for</u>

- Implementing a simple monitoring system that covers key aspects of the contract
- Appointing internal Hydro One staff to be accountable for managing the assignment
- Maintaining an element of control over how the work is to be performed ensuring an *employer/employee relationship* is not created
- Periodic review of performance based on contracting issues
- Matching invoices to agreed payment mechanism and terms. Performance of Consultants should be formally reviewed prior to contract payments being made
- Creating the environment for transfer of knowledge by allowing employees time for participation and training
- Ensuring procedures and approvals for the renewal, amendment and/or extension of Consultant contracts are determined by the cumulative value of the contract, are in accordance with the OAR and involve purchasing individuals.

4.5.2 Evaluating Performance

Upon completion of the contract, an overall evaluation of the Consultant's work will be conducted within the engaging unit, usually by the Project Manager. A copy of the evaluation of all Consultant contracts must be forwarded to Manager- Supply Chain who will maintain a central repository. This allows Consultants' previous performances to be reviewed when subsequent engagements are being considered.

Questions to ask yourself when the Consultant presents the diverables/recommendations:

i. Product delivered as defined in the Terms of Reference?
ii. Real issues/project objectives addressed?
iii. Recommendation logical and practical?
iv. Next steps clear?
v. Potential savings/benefits attained/attainable?
vi. Transfer of knowledge occurred?
vii. Costs on/under budget?
viii. Target dates and accountability met?
ix. Customer expectations met?

4.5.3 Retention of Deliverables

A soft copy of all contract deliverables in report format shall be kept by the Requisitioner. This affords the opportunity to leverage Hydro One's intellectual property for subsequent projects or engagements.

5.0 Exceptions

In rare instances when criteria are met for the "special circumstance" to apply, the Corporate Procedure for Purchases of Materials and Services of an Extremely Sensitive and Confidential Nature (Appendix F) shall be adhered to.

"Emergency" situations shall be handled in accordance with the Procurement Procedures.

6.0 Definitions

Hydro One defines "**Consultant**" as a person or organization that is retained to give professional advice or services which add intellectual property value for a fee, and is not deemed an employee of Hydro One (see Appendix B). A Consultant undertakes to accomplish a specific result and is largely free to employ his or her own means in the manner he or she deems most appropriate to achieve the results. Hydro One is not normally involved in the performance of the work, other than to see that it is completed in accordance with the agreement. There are generally clear deliverables associated with the work and payment is tied to milestones, deliverables, or completion. In some instances, reimbursement is based on a "time and material" basis and in rare cases on a "retainer" fee basis. Reimbursement is through Accounts Payable. Consultants include companies, individuals, "rental staff" or agency staff.

Consultants provide services in the form of advice, counsel and/or recommendations in areas such as organizational design and planning, productivity, efficiency, public relations, recruitment, business process re-engineering, bench-marking, research and development, studies requiring specialized professional expertise in areas such as environmental studies, engineering design, architectural services, research and development, laboratory services, custom designed software, information technology systems, executive searches or other HR professional services, custom developed surveys for marketing and energy management (including feasibility studies), energy audits, and custom developed training.

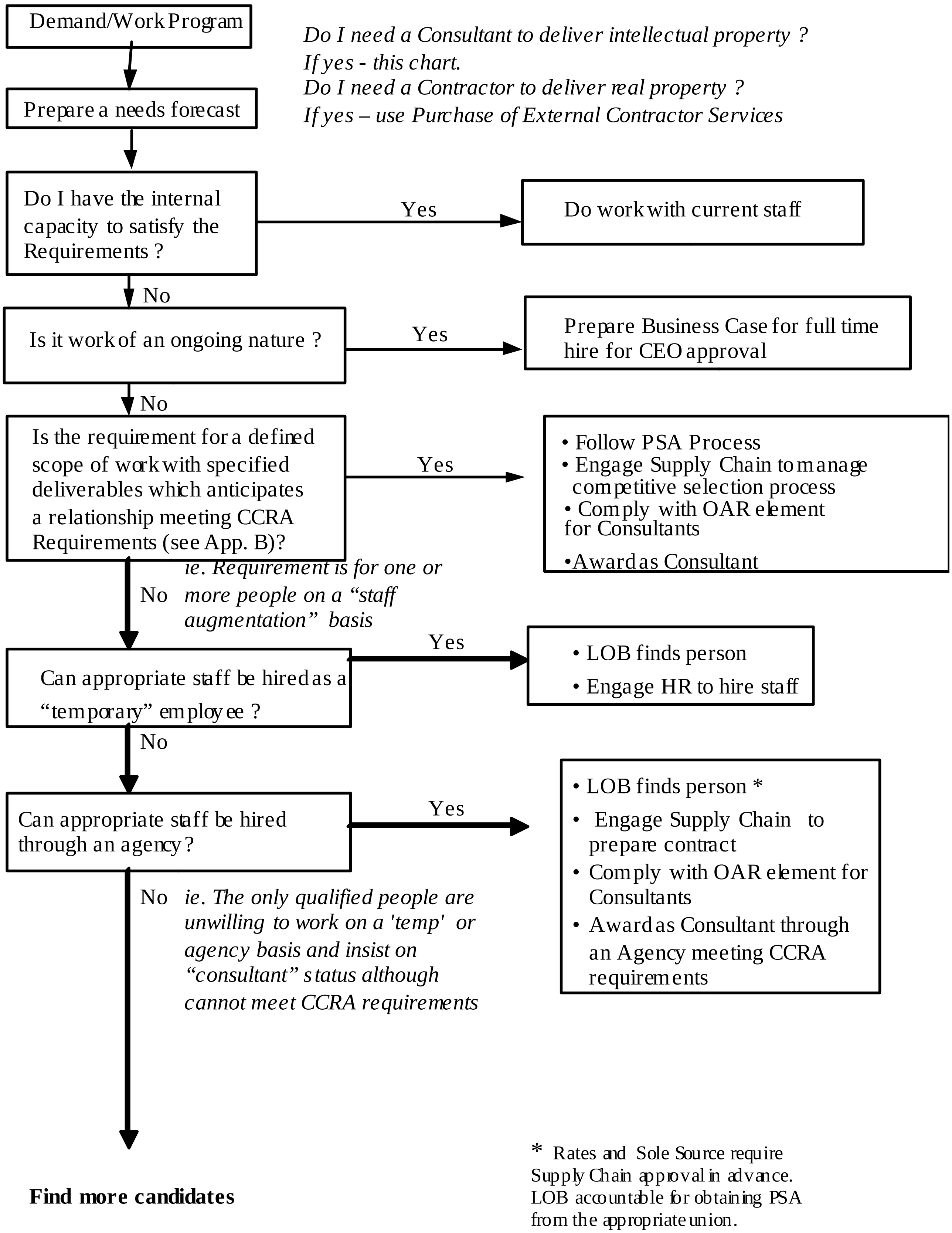
Hydro One defines "**Employee**" as a person hired on a temporary or full time basis by Hydro One and reimbursed through Hydro One's payroll system.

Hydro One defines "**Contractor**" as a person or organization that is retained to supply equipment, materials or construction/maintenance services required in order to complete a work program which adds to real property value and is not deemed an employee of Hydro One. A Contractor undertakes to accomplish a specific result and is largely free to employ his or her own means in the manner he or she deems most appropriate to achieve the results. Hydro One is not normally involved in the performance of the work, other than to see that it is completed in accordance with the agreement. There are generally clear deliverables associated with the work and payment is tied to milestones, deliverables, or completion. In some instances, the engagement is based on a "time and material" basis. Reference HODS SP0312 Purchase of External Contractor Services (non-Local Purchase Order).

7.0 References

SP0707 Corporate Policy on Consultants
SP0708 Procurement Policy
SP0826 Procurement Procedures

Appendix A: Employee versus Consultant – Decision Analysis Process



Appendix B: Meeting CCRA Requirements – Consultants

Note: In order to be retained as a Consultant, a person or corporation must meet the definition of a "consultant" versus "employee" in all four of the tests described below.

Employee	**Consultant**
1. Control ("master – servant relationship") Test:	
• Hydro One has the authority to control not only what is done, but also the manner in which it is done • An employee is subject to the direction and control of Hydro One, for example, the time, place and manner of doing the work.	• An independent consultant undertakes to accomplish a specific result and is largely free to determine the time, place and manner he or she deems most appropriate to achieve the result. • Hydro One is not normally involved in the performance of the work, other than to see that it is completed in accordance with the agreement.
2. The Integration Test:	
• The person is an integral part of the Hydro One team and performs a core business function for the duration of the engagement.	• The person's work, although important to the business is not an integral or core part of it, but is only accessory or "add-on" to it.
3. The Economic Reality Test:	
• An employee's earnings are not entirely tied to a specific deliverable or contracted result. • An employee does not bear any financial risk and has no opportunity to profit or risk of loss arising from the work performed. • Tools, equipment and supplies are supplied by Hydro One.	• A consultant is an entrepreneur who is contracted for a specific task and generally has a chance of profit or risk of loss with respect to the contracted work • Tools, equipment and supplies other than those of a Hydro One specialized or secure nature are supplied by the consultant • The consultant generally has more that one client (or seeks to have more than one client) to render the business economically viable.
4. The Specific Result Test:	
• An employee is required to place his or her personal services at the disposal of the company on a regular basis to perform such duties as may be assigned by the company. • The employee is required to perform the services personally.	• A consultant relationship normally pertains to the carrying out of a particular task, the focus of attention being mainly on the result to be accomplished from the working relationship. • The work may be done personally or by another person hired by and under the supervision of the consultant.

Appendix C: Re-employment of Former Employees

Purpose

As a general principle Hydro One prefers to not re-employ, either directly through the payroll system or through any agency, contract or purchase order former employees of Hydro One, Ontario Hydro Services Company or Ontario Hydro who left through normal retirement or with a severance package of any sort. This does not include former employees who left the company of their own free will, accepted no severance package or pension. Hydro One practices succession planning as a means for planned and cost effective rejuvenation of its staff complement. Re-employing retirees or former employees who left with a severance package as a normal means of conducting our business does not support this direction.

This principle promotes recruiting and training of new staff to fulfill ongoing business needs rather than using former employees.

This principle prevents former employees in receipt of a pension or severance payment from "double dipping" while performing on an ongoing basis essentially the same duties as when employed by Hydro One.

This principle does not prevent companies that employ former employees of Hydro One, Ontario Hydro Services Company or Ontario Hydro from participating in and winning tender competitions for Hydro One work provided that former employees do not own, have options on or receive benefit now or in the future from in excess of 10% of the shares of the company and are not the primary or significant factor in the selection of the company.

Procedure

The vice-president of each LOB shall ensure that temporary staff or Consultants retained by the LOB comply with the principles stated above. All application exceptions require prior approval of the CEO upon recommendations of both the vice-president of the LOB and Human Resources. Human Resources shall obtain CCRA approval where required.

Former Employees who were terminated for cause shall not be re-employed.

When Supply Chain is engaged by the LOB to manage the competitive and award process of a contract on behalf of the LOB for any materials or services, the Manager - Supply Chain shall ensure that the company and its staff are in compliance with the ownership principle stated above.

Appendix D: Travel Time and Expense Guidelines – Consulting Services

Consultants shall be reimbursed in accordance with the specific terms of their contracts. They will not normally be required to submit time sheets or expense reports with their invoices. Consultants shall retain such records on file for a period of seven years and shall make them available for audit purposes by either Hydro One internal or external audit personnel. Such records shall be in a form and contain sufficient information to substantiate the amounts invoiced to Hydro One. Consultants shall be responsible to ensure that only those expenses which meet CCRA requirements for deductibility as a business expense are claimed as expenses.

In order to determine what time and expenses may be invoiced to Hydro One, unless the Consultant agreement specifies otherwise, the following guideline shall be used.

Time

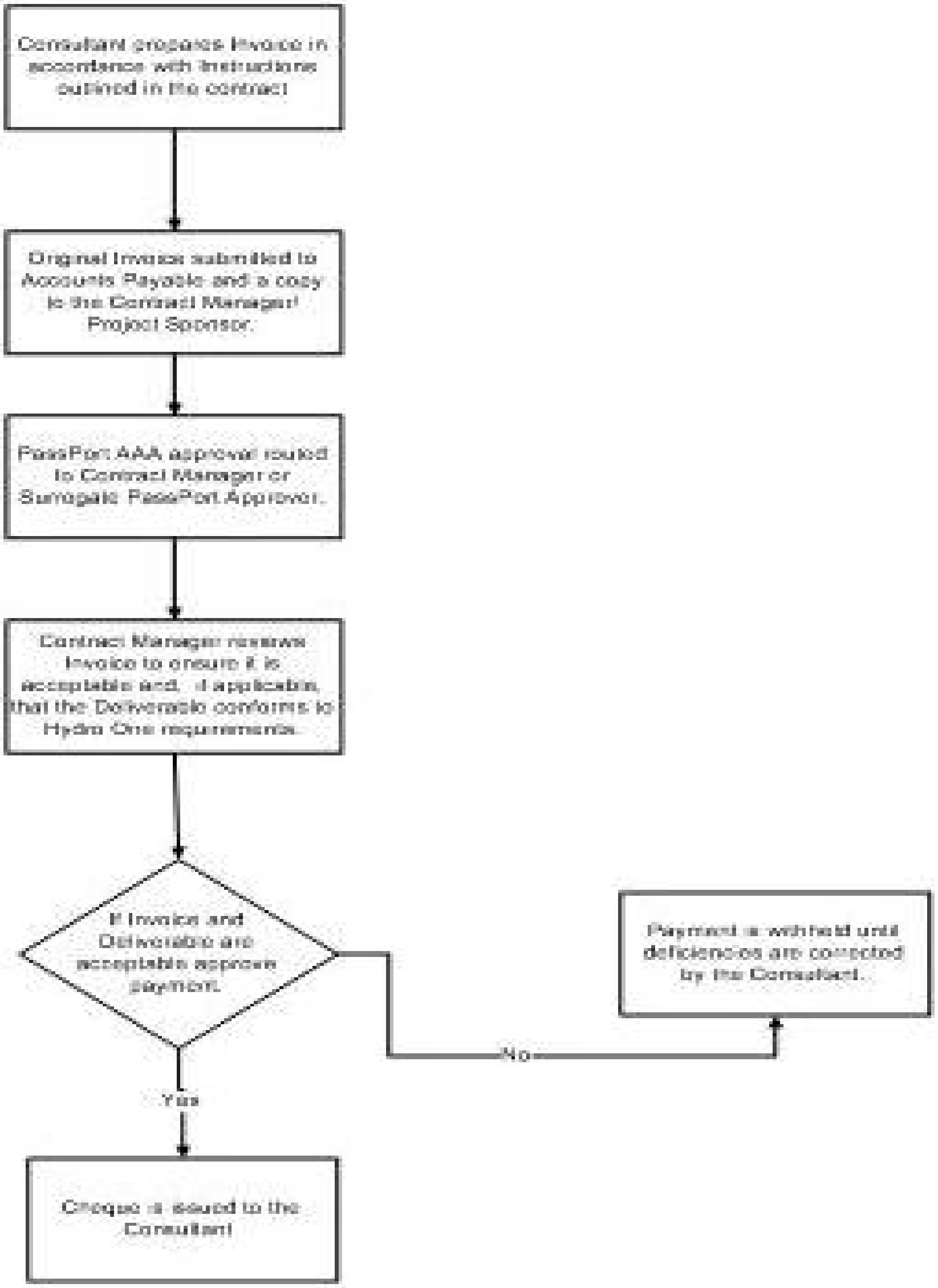
1. Hydro One Networks Inc. (HONI) will not reimburse the Consultant for travel time to commute to and from the normal place of work specified in the contract.

2. If the Consultant's attendance at a different place of work is required at the beginning or end of a day (or the whole day) HONI will reimburse for the incremental commuting time. For example: If it takes 1 hour to commute to Trinity and 1 ½ hours to commute to the alternative place of work, HONI will pay for ½ hour of time each way in addition to the time worked. Travel time in this case will be reimbursed at straight time.
3. If the Consultant's attendance is required away from the normal workplace during the day but the day starts and ends at the normal place of work, HONI will reimburse the Consultant at straight time for the travel time between the normal place of work and the alternative place of work as part of the normal day's work.

Travel Expense

1. HONI will not reimburse the Consultant for the cost of commuting from their residence to the normal place of work.
2. If the Consultant normally commutes to the normal place of work by foot, bicycle or public transit but drives to an alternative place of work (at the request of HONI) on a particular day, HONI will reimburse the full cost of travel to and from residence to the alternative place of work. This may be by personal vehicle or, with manager's approval, by rented vehicle. For example: If a Consultant normally takes public transit to Trinity each day and instead drives 100 km round trip to and from their residence to an alternative place of work, HONI will reimburse the full cost of the 100 km round trip.)
3. If the Consultant normally drives to the normal place of work but drives to an alternative place of work on a particular day, HONI will pay only the incremental cost of driving to and from the alternative place of work. For example: If a Consultant normally drives 30 km round trip to and from Trinity each day and instead drives 100 km round trip to and from an alternative place of work, HONI will reimburse the cost of the additional 70 km.
4. If the Consultant normally drives to the normal place of work and during the day travels to and from the normal place of work to another place of work, HONI will reimburse the full cost of that round trip between the two work locations.
5. Mileage shall be reimbursed in accordance with the rates established by HONI's HR Department and are posted on HONI's Ask HR Intranet website.
6. Expense receipts must show the vendor GST number wherever possible.

Appendix E: Administrative Process for Invoicing and Payment



Hydro One will accept invoices on a bi-weekly basis for an independent Consultant. Terms and schedule for payment for other consulting engagements will be in accordance with Hydro One's standards terms, unless otherwise stipulated in the contract.

Appendix F: Corporate Procedure for Purchases of Materials and Services of an Extremely Sensitive and Confidential Nature

SPECIAL CIRUMSTANCE

There are special circumstances where the Corporation is required to purchase services or materials for work that is of an extremely sensitive and confidential nature. Examples of this work could include making security arrangements for senior executives or obtaining financial advice on a potential acquisition where senior management deems it prudent that knowledge of the transaction be limited and be on a need to know basis.

In these circumstances a departure from Corporate Purchasing Procedure means:

- Restricting the involvement of Purchasing Individuals and/
- Not issuing a standard purchase order and recording the purchase in Corporate Purchasing systems.

REQUIREMENTS

1. The requisitioning authority must be a direct report of the President with the position of Vice-President or higher. To use the special circumstance, the requisitioning authority must be able to demonstrate that there is significant risk if confidentiality is not maintained and other options for working within normal purchasing procedure is not viable. The guideline, which follows, provides help in the application of these criteria.
2. The CFO must approve the purchase. Where the CFO is the requisitioning authority, the President must approve the purchase.
3. The CFO must be consulted in the development of the terms and conditions of the contract to ensure Corporate Contract Standards are met.
4. The CFO will maintain a Purchase Order/Contract system for special circumstances.
5. The requisitioning executive will be accountable for ensuring all other aspects of Corporate Purchasing Policy and Procedure and Hydro’s Standard Internal Control Objectives are met over the full life cycle of the purchase.
6. The CFO will approve payment for invoices signed by the requisitioning authority confirming receipt of contract deliverables.
7. The CFO will periodically report to the CEO on the exercise of the authority for this special circumstance with copies to the General Auditor.

GUIDELINE AND CRITERIA FOR USE

The following questions must be addressed to ensure the need for the special circumstance is justified:

1. *Are one or more of the following criteria met in describing the need for confidentiality? These circumstances involve material risk if confidentiality is breached and may result in:*
    - personal risk of injury or harm to employees
    - personal risk of injury or harm to the public,
    - risk to Corporate assets,
    - risk to Corporate competitive advantage, or
    - Corporate relations risk.

2. *Could the confidentiality needs be met by an alternative approach that stays within Corporate Purchasing Policy and Principles and general procurement procedures as described Case 1 and Case 2 below?*

Case 1: Blanket Service Contract
Pricing and terms and conditions are established (e.g. financial valuations of potential acquisitions and financial strategic advice) as per the normal purchasing process and the supplier retained on a blanket contract basis. While the blanket contract would be awarded based on competition with the assistance of Purchasing Individuals, the line manager would award specific work packages within the terms of the blanket package without further involvement of purchasing.

This minimizes risk with respect to vendor selection, price and contract terms while also minimizing risk associated with many aspects of contract confidentiality. It would not be appropriate where the name of the vendor could compromise security such as the name of a provider of security services to senior executives. Also the same vendor may not be appropriate for all of the different issues that arise for initiatives such as financial valuations.

Case 2: Contract Terms and/or Deliverables not Described in Purchase Order

Where there is concern about maintaining confidentiality about the terms and or deliverables of a contract with a supplier, the specific contract terms and/or deliverables may be separated from the Purchase Order and kept on a confidential basis by the senior executive accountable for negotiating the acquisition of the service. The accountable executive would consult with Contract Management to ensure that Corporate requirements and standards are understood and complied with. While a purchase order is raised, contract terms and conditions are not divulged on it. In this way specific terms and conditions are not communicated to Purchasing Individuals or others who do not have a need to know.

For both cases, there is a record of the purchase and payment to the supplier is facilitated through the purchase order.

ATTACHMENT 1 to APPENDIX F

EXECUTIVE AUTHORITY ELEMENTS

4.01 – GENERAL REQUSITIONING

4.02 - GENERAL PURCHASING

4.02. 3 Purchases of Services and Materials of an Extremely Sensitive and Confidential Nature - Special Circumstance

President/CEO	UTAL
CFO	$ 5 M

Notes:

1. These authorities are not to be further delegated. Where the CFO requires the approval of a special circumstance contract, purchase approval is provided by the CEO.

2. Use and application of this authority must meet criteria and guidelines in the special circumstance to *Corporate Procedure for the Purchases of Materials and Services of an Extremely Sensitive and Confidential Nature.*

Appendix G: Security Checks

BUYING GUIDE	
Title: SECURITY CHECKS	
Guideline No: BG- F-040	**2004 REVISION (NEW)**

SCOPE

This Guideline reviews the use of security checks. The responsibilities of purchasing staff including the determination of the need, solicitation of bids and consent, evaluation, approvals, and awarding are covered in this Guideline.

OVERVIEW

Hydro One onducts security checks on employees and vendors as a means to protect its employees, customers, assets and information.

This procedure addresses the requirements and the process to obtain security checks when contracting externally for contract staff and other goods and services.

TYPES OF ENGAGEMENTS REQUIRING SECURITY CHECKS

There are three types of security checks conducted by Corporate Security: criminal record, driver's licence and credit ("Checks"). Not all contract staff, consultant, material or service requirements require that any or all Checks be performed. It is the responsibility of Hydro One and Inergi purchasing individuals ("Purchasing Individuals") to assess the requirement and to determine what Checks, if any, are required.

Any engagement that matches any or all of the following conditions will require Checks as described below in **Types of Checks**. It is the responsibility of Supply Chain to assess the requirement and determine what Checks are required:

#1 - access to Hydro One computer systems. This includes access to PassPort and/or PeopleSoft and/or Financial Data Mart - all Hydro One locations,

#2 - performing work for Hydro One regarding financial approvals or determining Hydro One financial controls/authorities - all Hydro One locations,

#3 - unescorted access to any transmission station ("TS"), switching station ("SS"), distribution station ("DS") or control centre ("CC") (includes both NOD and Telecom control centres in Barrie and Richview) - this does not include service centres, head office, Markham Call Centre, Warehouses, Fleet Garages, Construction Yards, Temporary Work Centres, Metering Shop, Hydro One Brampton Offices

See also **Attachment "A"** Sample Services listing goods and services generally provided to Hydro One by external vendors and indications of when such services would require Checks to be performed. This is not an all-inclusive list. When in doubt, contact Director, Corporate Security, for direction.

Escorted access to any "TS", "SS", "DS" or "CC" does not require Checks to be performed. See sub-section entitled "Special Terms and Conditions - Escorted Access". **BG-F-041 – STATION ACCESS AUTHORIZATION** must be followed, in addition to this Guideline, when unescorted or escorted access is required at any SS, DS, TS, or CC.

TYPES OF CHECKS

Credit Check required when the engagement meets #1 or #2 conditions defined above.

Driver's Licence Check required when the engagement requires that the individual drive while engaged in doing work for Hydro One or to drive on or park on any of Hydro One's TS, SS, or DS properties.

Criminal Record Check required when the engagement meets #1, #2 or #3 conditions defined above.

Escorted access to any transmission station ("TS"), switching station ("SS"), distribution station ("DS") or control centre ("CC") does not require any of the three types of Checks to be performed. Driving on or parking on a Hydro One CC property does not require a Driver's Licence Check.

PROCESS

DETERMINING THE NEED FOR CHECKS

Determine if the requisitioned goods or services, including contract staff and consultant engagements, require criminal record, driver's licence and/or credit checks to be conducted on potential vendor(s), its employees and contractors, its subcontractors and their employees. Refer to the definitions supplied earlier in this document. Confirm if the access will be escorted. It may be necessary to contact the requisitioner or project coordinator to ensure a proper understanding of the requirement. Escorted access to any transmission station ("TS"), switching station ("SS"), distribution station ("DS") or control centre ("CC") does not require Checks to be performed. However, there is a requirement to include a clause in the Special Terms and Conditions of the RFx document. See sub-section 3.4 entitled "Special Terms and Conditions - Escorted Access".

MANDATORY REQUIREMENT

Include in the evaluation scorecard, as Mandatory, that the vendor is required to respond to say that it is willing to have employees and subcontractor employees sign a Security Check Consent, Authorization and Release form. Vendors not willing to consent will not be considered for Hydro One business.

RFx DOCUMENTATION

Within the RFx documentation there are specific criteria, clause and section inclusions necessary when Checks or escorted access are a requirement. The following sub-sections provide further clarity:

EVALUATION CRITERA – CHECKS REQUIRED

Include in RFx Evaluation Criteria section along with other listed criteria: Agreement to complete Security Check Consent, Authorization and Release forms.

SPECIAL TERMS AND CONDITIONS – CHECKS REQUIRED

Include the following clause in the Special Commercial Terms and Conditions of the RFx documentation if not included in the appropriate Contract Standard:

Security Checks "Clause"

No employee, consultant, contractor or subcontractor of the Company shall:

(a) be assigned by the Company to assist the Company in providing the Purchaser with any of the services that are the subject matter of this Contract; or
(b) have access to any of the properties, offices, or confidential or propriety information of the Purchaser for the purpose of assisting the Company to provide any of the said services;

unless and until:

(i) the said employee, consultant, contractor or subcontractor has signed a Consent, Authorization and Release in the form that appears in **Attachment 1**, and the said signature on the Consent, Authorization and Release has been witnessed; and
(ii) the signed and witnessed Consent, Authorization and Release has been delivered to the Purchaser.

To that end, each individual employee of the Company and employees of all subcontractors expected to have access to any of the properties, offices, or confidential or proprietary information of the Purchaser for the purpose of assisting the Company to provide any of the said services; over the life of the contract are required to complete the attached forms (**Attachment 1** - Part 1 and 2 of the Security Check form).

- Once security checks have been successfully completed and an award has been made, Purchaser will issue letters to the Company representative authorizing site access to each applicant. Purchaser letter must be presented prior to access to Purchaser sites.
- The onus will be on the Company to ensure (over the life of the contract) that Security Check forms are completed and submitted to Purchaser for any new employees and subcontractor employees.
- The onus will be on the Company to ensure that any changes to the security status of any employee or subcontractor employee is brought to the immediate attention of Purchaser.

The aforementioned security requirements shall be in force prior to the commencement of services under the contract and shall remain in force during the entire term of the contract. Notwithstanding anything else in the contract:

(a) the Company shall not commence providing the said services prior to the Company's receipt of Purchaser letters authorizing site access to each applicant. Purchaser letter must be presented prior to access to Purchaser sites;

(b) if the security status changes of any employee or subcontractor employee during the term of the contract, the Company shall not continue providing the said services utilizing the employee or subcontractor employee until such time as the Company receives from Purchaser a letter authorizing site access based on said changed security status. In such an event, the Company shall diligently endeavor to complete the work in accordance with the schedule set forth in the contract and, if necessary, will increase the level of effort necessary to ensure the schedule is maintained. Any price or funding limitations shall not be exceeded without the Purchaser's prior written authorization, notwithstanding any extra efforts required to maintain schedule.

(c) in addition to any other remedy that the Purchaser may have against the Company as a result of the Company's failure to comply with all the terms of this clause, the Company shall, to the extent that delay in providing the said services occurs as a result of the non-delivery of signed and witnessed Security Check Consent, Authorization and Release forms as required by (a) and (b), be liable to the Purchaser for all damages arising out of the said delay.

FORM FOR SUBMISSION – CHECKS REQUIRED

Include a section in the Form for Submission for the Company to acknowledge it will comply with the above clause if selected as the successful proponent/bidder. Upon submission of RFx response, it is not required that the vendor sign the forms. Signing of the forms will be required just prior to award. A sample section to include in the Form of Submission can be found below:

SECURITY CHECKS - - MANDATORY - FORM FOR SUBMISSION "CLAUSE"

The Company agrees that clause ***(insert clause number)*** of the Special Terms and Conditions contained in this ***(state RFx document)*** will be one of the terms of any contract that may be entered into with the Purchaser. The Company further agrees it shall cause each individual employee of the Company and employees of all subcontractors expected to have access to any of the properties, offices, or confidential or proprietary information of the Purchaser for the purpose of assisting the Company to provide any of the said services over the life of the contract to complete and duly sign and have witnessed the attached form (**Attachment 1** - Part 1 Request for Security Check & Part 2 Security Check Consent, Authorization and Release).

Agreed - Yes __________

Agreed - No __________

NOTE: Vendors that do not indicate a willingness to have employees and subcontractor employees complete, sign and have witnessd **Attachment 1** will be disqualified. Hydro One must be satisfied in all respects with the results of all security checks to give further consideration to any submission. Upon submission of your response, it is not required that the form be signed. Signing of the form will be required prior to award.

SPECIAL TERMS AND CONDITIONS - ESCORTED ACCESS

Escorted access to any transmission station ("TS"), switching station ("SS"), distribution station ("DS") or control centre ("CC") does not require Checks to be performed. However, it is the responsibility of Purchasing Individuals to include the following clause in the Special Terms and Conditions of the RFx documentation when it has been deemed that the Company will have escorted access:

ESCORTED ACCESS

If any of the work or services provided pursuant to the Contract necessitate entry to one or more of the Purchaser's transmission stations, switching stations, distribution stations or control centres by the Company or its subcontractors or any person providing services to, or acting on behalf of, the Company or its subcontractors (collectively, the "Entrants"), no Entrant shall be permitted entry to any of the said premises unless accompanied at all times by an employee of the Purchaser or another person appointed by the Purchaser to provide such accompaniment. It shall be the responsibility of the Company to arrange such accompaniment, and the Company shall ensure that no Entrant shall enter or attempt to enter the said premises without such accompaniment.

SECURITY CHECK CONSENT, AUTHORIZATION AND RELEASE FORM

When attaching the sample form to the RFx Documentation, as required by reference of **Attachment 1** in the RFx Security Check - Special Terms and Conditions clause and Security Check section of the Form of Submission, it is the responsibility of the Purchasing Individuals to update the sample to reflect the type of Checks Hydro One requires to be performed (i.e. credit, driver licence and/or criminal record). See **Attachment "B"** Security Check form Part 1 and 2 for RFx inclusion.

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Note: Ensure **Attachment "1**" numbering is numerically appropriate, i..e. ensure the RFx documentation does not contain two attachments named "Attachment 1".

EVALUATION

Those vendors not indicating a willingness to have employees and subcontractor employees complete the Security Check, Consent Authorization and Release forms are to be disqualified and will not be considered for award of Hydro One business. Normal evaluation process to be followed.

RECOMMENDATION AND APPROVAL FOR AWARD

When requirements dictate that a Memorandum for Purchase Approval (MPA) be processed and approved prior to award of a contract, Purchasing Individuals shall ensure that the competitive details clearly name the responding vendors that were disqualified based on unwillingness to have employees sign Security Check Consent, Authorization and Release forms. The document shall also indicate in the opening first paragraph that the award is contingent on:

(a) the vendor(s) providing duly signed and witnessed Consent, Authorization and Release Forms; and
(b) the OPP's providing Corporate Security with a status report and Corporate Security providing "Clearance" based on a positive assessment by Corporate Security of criminal record, driver licence/history and credit information *(listed as appropriate to that particular requirement).*

When requirements do require a Memorandum for Purchase Approval be processed and approved prior to award of a contract, Purchasing Individuals shall ensure that the Review and Justification tab (P.O. panel 6) in PassPort clearly an indicates that the awarded Company was provided "Clearance" by Director, Corporate Security.

When requirements do not require a Memorandum for Purchase Approval be processed and approved prior to award of a contract, Purchasing Individuals shall ensure that the Review and Justification tab (P.O. panel 6) in PassPort clearly includes the names of responding vendors that were disqualified based on unwillingness to have employees sign Security Check Consent, Authorization and Release forms or by failing to obtain "Clearance" by Director, Corporate Security, and an indication that the awarded Company was provided "Clearance" by Director, Corporate Security.

SOLICITING SIGNED CONSENT FORM FROM RECOMMENDED & APPROVED VENDOR(S)

Complete the cover sheet and portions of Part 1 Request for Security Check form to be completed by Requestor (Purchasing Individual). Sign the Request for Security Check form. Provide vendor(s), by fax, courier or mail as appropriate, with the cover sheet, Part 1 Request for Security Check and Part 2 Security Check Consent, Authorization and Release form for signature. Fill in "Job Title" by inserting vendor name and reference to the RFx. This will ensure ease of reference on return of vendor signed copies. SEE SAMPLE **ATTACHMENT "C** " (Cover Sheet and Form for vendor signature). Expedite the return of the forms, as necessary.

Note: You will notice Part 1 Request for Security Check directs the Requestor (Purchasing Individual) to indicate access/exposure areas. Within the selection are Human Resources/Labour Relations Information, Hydro One Proprietary Information and Hydro One Marketing and/or Business Strategy. Within the external contracting process these areas of exposure are generally covered by agreement to a Confidentiality clause or the signing of a Confidentiality/Non-Disclosure Agreement. It is not necessary to submit a Request for Security Check for engagements where these, or any combination of these, selections are the sole area(s) of exposure Therefore, **the only applicable selections are**: Hydro One Finances and/or Financial Information; Access to/use of Hydro One vehicles; Other: (Please State). Refer to definition earlier in this Guideline to determine applicability. Other would include "unescorted access to a TS, SS, DS or CC".

FORWARDING SIGNED CONSENT FORMS TO CORPORATE SECURITY

Signed consent form(s) to be faxed by Purchasing Individual to Corporate Security Confidential fax at 416-345-6861, Attn: Chris Price Director, Corporate Security. The Purchasing Individual's name, contact number, signature must be on the form as Corporate Security's initial contact if there are any issues. Also ensure that the "Job Title" is completed. If there are going to multiple companies awarded the requirement, insert the prime Company name. This is to ensure that the Purchasing Individual is able to easily match Corporate Security's response to the original requirement. Once the assessment has been completed, the Purchasing Individual on the form will be the only individual notified by Corporate Security.

ASSESSMENT

Corporate Security will contact OPP to solicit criminal record and driver licence data. This generally takes up to fifteen days. Corporate Security will perform an assessment of persons' criminal, credit and driving record history, as appropriate. This is generally completed in 24 hours.

CLEARANCE

Corporate Security will provide "Clearance" to Purchasing Individual by forwarding an authorized "Request for Security Check" form. The Request for Security Check form will indicate the security status with either an A, A* or D.

" A " means that access has been granted outright
" A* " means there are some minor concerns and the Purchasing Individual and Director, Corporate Security will have discussed the issues.
" D " means access is not granted.

As there may be numerous Applicants (employees of vendor and/or employees of subcontractors) for one vendor, it may or may not be relevant that a "D" security status on one or more Applicants exists. The withdrawal of the one candidate to perform the work may not require another candidate for replacement as sufficient workforce may have been approved for access. It may, however, require that the vendor provide new Applicants for Corporate Security assessment. It may require the vendor to be disqualified based on access not being granted to one or more Applicants. In any case, Applicants allocated a "D" security status will not be granted access to Hydro One properties. Director, Corporate Security will discuss the options specific to each individual project with the Purchasing Individual and the appropriate course of action will be devised. It will be carried out by the Purchasing Individual.

NO CLEARANCE

Should "Clearance" not be granted, the Purchasing Individual may participate in discussions with Corporate Security as to "next steps".

If no opportunity exists to resolve, vendor shall be notified by using the sample letter format **(Attachment "D"** Sample letter to vendor not receiving "Clearance"). This step should not be taken without direction from Director, Corporate Security and consultation with the Supervisor. There is no requirement to send notification to each of the applicants. One letter addressed to the vendor will suffice. Requisitioner and major stakeholders shall be notified. Second place bidder, based on evaluation, shall be pursued. Approval documents will be updated following Guideline BG-E-012 Instruction Notices – Amendments (Changes) revising the Memorandum for Purchase Approval as required, and the process steps of this Guideline from "SOLICITING SIGNED CONSENT FORM FROM RECOMMENDED AND APPROVED VENDOR" onward will be repeated.

AWARD OF CONTRACT

Upon receipt of "Clearance" in the form of authorized "Request for Security Check" from Corporate Security and upon settlement of all other terms and conditions, Purchasing Individual shall provide vendor with a Purchase Order/contract for execution that includes the following clause:

- The onus will be on the Company to ensure (over the life of the contract) that Security Check Consent, Authorization and Release forms are completed and submitted to Purchaser for any new employees and subcontractor employees. When doing so, please reference the Purchase Order number.
- The onus will be on the Company to ensure that any changes to the security status of any employee or subcontractor employee is brought to the immediate attention of Purchaser. When doing so, please reference the Purchase Order number.

ISSUING LETTERS AUTHORIZING SITE ACCESS

Upon execution of the Purchase Order/contract, Purchasing Individual will issue letters to authorize site access to each Applicant. One letter per Applicant is required and the Purchasing Individual prepares and sends all of them to the attention of the Company representative. Purchasing Individuals are to ensure Applicants not receiving "Clearance" are not provided with letters authorizing site access. See sample letters **Attachment "E"** for sample letter.

PURCHASE ORDER FILE DOCUMENTATION

The Purchasing Individual shall ensure that copies of all related security check documentation is retained in the Purchase Order file.

CHECKLIST - RESPONSIBILITIES OF PURCHASING INDIVIDUALS

The following is a high level listing of the responsibilities of Purchasing Individuals when reviewing and addressing the need for Checks. The unique properties of the steps of the procurement process to be followed to carry out these responsibilities are outlined in the section of this Guideline entitled: PROCESS

- Always solicit the latest version of the Security Check form (Part 1 and Part 2) by accessing it at http://gridweb.hydroone.com/ecs/sms/index.html FORMS CABINET.
- Confirm whether the requirement necessitates escorted or unescorted access
- Determine whether the requirement necessitates credit, driver licence and/or criminal record checks.
- Include in RFx; Special Terms and Conditions a clause relating to security checks, a sample two Part form (Part 1 – Request for Security Check and Part 2 -Security Check Consent, Authorization and Release) and the Form for Submission question requiring vendor's to state willingness to consent to Checks
- Include in RFx Special Terms and Conditions, as applicable, a clause relating to Escorted Access on any transmission station ("TS"), switching station ("SS"), distribution station ("DS") or control centre ("CC") properties
- Evaluation criteria disclosed to vendors and internal evaluation scorecard shall include mandatory requirement for vendor to respond saying that it is willing to have employees and subcontractor employees sign a Security Check Consent, Authorization and Release form
- Disqualify those responses not indicating willingness as above
- Ensure purchasing approval documents include details of credit, driver licence and/or criminal record checks relevant to the evaluation and the recommendation
- Complete and sign Request for Security Check - Part 1 . Ensure "Job Title" includes reference to the RFx in order to effect ease of reference on return of vendor signed copies
- Solicit, and expedite as necessary, completed Part 1 and signed Part 2 - Security Check Consent, Authorization and Release Form(s) from recommended vendor(s)
- Forward signed two part form (Part 1 – Request for Security Check and Part 2 - Security Check Consent, Authorization and Release Form(s) to Corporate Security
- Participate in discussions with Corporate Security personnel as required
- Issue contract/Purchase Order only after receiving Corporate Security "Clearance"

- Ensure contract/Purchase Order highlights obligations of vendor with respect to changes in security status and new employees
- Issue letters to the vendor's representative to authorize site access to each applicant
- Retain a copy of all related security check documentation in the Purchase Order file

These appendices may be revised from time to time by the Manager – Supply Chain Services in order to ensure the implementation of the intent of this Procedure.

Appendix H: Document Management

Owner/Functional Responsibility	Supply Chain Services
Approval Date	March 15, 2005
Approval Required By	VP Supply Chain Services
Effective Date	March 15, 2005
Document Last Reviewed	August 2008

Document Number: **SP 0706 R0**

Document Name: **Corporate Charge Card Procedure**

Issue Date: **July 2008**

When in printed form, this document is uncontrolled.
It is the user's responsibility to verify that this copy matches the document on the Hods website.

The requirements of this document are mandatory.

Purpose

This procedure specifies requirements relating to the use of the Corporate Charge Card (currently Bank of Montreal MasterCard).

Revision

Information contained in the policy, approved in March 2008 , is now contained in this document.

Contents

1.0 Scope

This procedure specifies requirements relating to the use of the Corporate Charge Card (currently Bank of Montreal MasterCard), and applies to cardholders, Supervisors, Local and Corporate Charge Card Coordinators and financial staff involved in the processes.

2.0 Governing Principles

The intent of this procedure is not to supercede the existing central purchasing process. The Corporate Charge Card should be utilized as the preferred method of payment where appropriate (see guidelines below).

Where cost and risk are justified, the Corporate Charge Card is to be issued to Hydro One staff for processing employee business expenses and purchases of materials and services (local purchasing) for Hydro One.

The Corporate Charge Card is a payment mechanism only, and possession of one does not imply authority to incur expenses, make purchases or make payments.

Expenditures on the Corporate Charge Card are to comply with all pertinent corporate policies and procedures. The card is **not** to be used for personal expenses, but only for valid business expenses.

All Corporate Charge Card purchases and authorizations of Corporate Charge Card statements must be in accordance with the Executive Authority Register (EAR)/Organizational Authority Registers (OARs) and associated policies and procedures.

Corporate Charge Cards can only be issued to and utilized by Hydro One employees including temporary and hiring hall employees. Exceptions must be deemed reasonable and include:

- Inergi personnel may obtain a CCC if approved by a Hydro One MCP Manager in the related functional area and in accordance with the Corporate Charge Card limits set out in Guidance F of the EAR/OARs.
- Contract employees may obtain a CCC if approved by a Hydro One MCP Manager in the direct line of authority based on criteria in Section 4.2 and the Corporate Charge Card limits set out in Guidance F of the EAR/OARs. The same processes apply as to regular Hydro One employees, however, the Supervisor is also required to complete/sign a "Corporate Charge Card Usage by Non-Hydro One Employees - Supervisor Terms and Conditions" form (see Appendix D).

3.0 Definitions

CCC	Corporate Charge Card
CCCC	Corporate Charge Card Coordinator
LCCC	Local Charge Card Coordinator
BMO	Bank of Montreal
details Online™	DOL (Bank of Montreal's web-based MasterCard database)
SCM	Supply Chain Management
FLM	First Line Manager
EAR	Executive Authority Register
OAR	Organizational Authority Register

4.0 Guidelines

The purpose of the Corporate Charge Card (CCC) is to enhance the payment processes for employee business expenses, local purchasing, and other exceptions as determined by Supply Chain Management (SCM) or the Corporate Controller. Use of the CCC expedites payments and reduces overall costs to Hydro One by eliminating the administrative efforts associated with the payment process while maintaining expenditure control (e.g. Material Requisitioning/invoice approvals for local purchasing). Authorized employees are empowered to use the card in accordance with the criteria established in associated policies and procedures.

The CCC can be established for employee business expenses (travel), reimbursements as well as Work Orders or Projects. The CCC is to be used for local purchases, as defined by the Local Purchasing guidelines.

A CCC can also be established for other types of spend within a line organization and must be approved by an MCP Manager in the direct line of authority and in accordance with Guidance F of the EAR/OARs.

Other examples include:

Payments to Bell Canada and Allstream are processed via CCC. Both of these cardless cards utilize blocking features which allow only the specific vendor to charge to them.

Fleet Management Services utilizes the CCC to process their MTO Licensing payments.

For all Capital Contribution Refunds please refer to the following link:

http://operations.hydroonenetworks.com/web/sub/BusProcInfo/Assets/Hydro_One_Customer_Capital_Contribution_Refund_Process.doc

4.1 Local Purchasing

Local Purchasing is generally defined as the acquisition of materials and services under $15,000. There are many exceptions to this general definition. The full definition can be found in Section 3.0 of the Local Purchase Procedure located at:

http://finance.hydroone.com/Supply_Chain_Services/Policies_and_Procedures/default.htm

This procedure should be thoroughly reviewed with attention being paid to goods & services that do not constitute a local purchase and therefore cannot be paid for using the CCC. For example but not limited to: protective clothing and safety equipment, donations, minor fixed assets and consultants. In some situations, approval may be obtained to procure these items via the CCC. The purchase of Contractor Services must follow guidelines specified in the Local Contractor and Material Purchase Process.

All local purchasing must be done within the guidelines of the Code of Business Conduct for Employees (see HR website).

Where cardholders transact using their CCC for items greater than $15K, approval must be obtained by the Manager Supply Chain. Evidence of approval can be either attached to or referenced on the respective CCC statement.

4.2 Criteria in Determining Staff to be Provided with Corporate Charge Cards

Consideration should be given to providing a card to an employee, where there is an identified need in the performance of their job function (e.g. ongoing business expenses and/or local purchasing).

Cards can be issued for employees or for a Work Order/Project ID/OM&A account. CCCs issued for a Work Order/Project ID/OM&A account are associated to a designated employee (Card Administrator) who is responsible for the CCC.

4.3 Criteria in Determining Work Orders/Project IDS/OM&A Accounts to be Provided with Corporate Charge Cards

A CCC can be established for a Work Order. It is recommended that a Work Order card be obtained for those work orders where there is a need for local purchasing, a need to accumulate costs at the work order level, and the length of the work order exceeds one month. For work orders that are expected to be open for less than one month, a CCC could still be obtained at management's discretion, if the volume of transactions expected to be processed on the card warrant.

All Work Order cards will be issued to an individual, known as the Card Administrator, who is responsible for the card. The Card Administrator will be responsible for ensuring that all CCC statements are reconciled on a monthly basis (i.e. all receipts/supporting documents are attached) and forwarded to the appropriate Supervisor for authorization - see Section 4.11 Authorization Process.

A CCC for a Work Order could be set up as a cardless CCC (i.e. no plastic issued). To obtain a CCC associated with a Work Order, proper authorization must be obtained in accordance with Guidance F of the EAR/OARs - see Section 4.4 below, and the application should be processed through the Local Charge Card Co-ordinator (LCCC).

Since each Work Order CCC will have a unique default account number associated with it, this will ensure that the costs are properly recorded to the Work Order in PassPort and are passed through to PeopleSoft. When WO distribution is used, the costs will flow to Task 01. These are mapped by Detailed Cost Element (DCE) so that in most circumstances, the user will see what type of cost has been incurred.

The cardless CCC number can be utilized by individuals other than the Card Administrator, where deemed appropriate. The card number and expiry date should only be provided to employees who have a legitimate need to charge against that card. The Card Administrator will be responsible for monitoring the costs charged against that CCC. The supporting documentation (e.g. vendor's invoice, packing slip) must be forwarded by all users of that Work Order card, to the Card Administrator on a timely basis.

The list of card numbers and expiry dates should be safeguarded, similar to a plastic card, to protect against unauthorized use. CCCs can also be set up for a Project ID or for an OM&A Account/Cost Centre. The same process would apply for Project ID and OM&A Account/Cost Centre cards as for the Work Order cards.

See Appendix A: Accounting & Capitalization Treatment of Corporate Charge Card Transactions.

4.4 Establishing Corporate Charge Card Limits and Cash Withdrawal Feature

The credit limits should be established consistent with the requirements and responsibilities of the applicant's position and the intended use of the CCC. The credit limit and cash withdrawal limits should be what the applicant would normally expect to incur on the card on a monthly basis. The credit and cash limits should be established to meet the reasonable, normal monthly requirements of the individual or Project/Work Order to whom it is issued.

Approval of the credit and cash limits (including temporary increases) will be by the direct line of authority and in accordance with the signing authority limits in Guidance F of the EAR/OARs.

4.5 Establishing Corporate Charge Card Accounting Distribution

The CCC process requires that one default distribution be established for each card.

Any new card that is set up, whether it is for an employee, Work Order, Project ID or OM&A Account, will require an associated default distribution. The Local Charge Card Coordinator will set up the default distribution number, as directed by Line Management who will indicate the default distribution number on either the Application or Work Order/Project ID/OM&A Application form. These default distribution numbers can be changed by the Local Charge Card Coordinators, at the direction of line management, on an as needed basis.

In the past, most of the CCCs had a standard OM&A default distribution number. With the introduction of Work Order and Project ID cards, the default distribution can be to the Work Order or Project ID.

It will be up to each line of business to establish how the card program can best be implemented to meet their business requirements and establish the parameters around the program to support this process. Parameters around distributions are established at the Business Unit levels, but can be established at any level below that (e.g. department level), within the confines of those set at the Business Unit level. The decision as to how the card default distributions are set up will be made by the lines of business and executed by the Local Charge Card Coordinators.

4.6 Redistributing Corporate Charge Card Charges

As a CCC can be opened for a Work Order, Project ID or specific OM&A account, the need to redistribute should be minimal.

There may however, be instances where charges are incurred against a CCC that is an OM&A Account Card which should be redistributed to a Work Order or Project ID. In such situations, redistribution may be required to ensure the costs are charged against the appropriate work order/project ID, where the costs are **material / significant**. Because redistribution attracts incremental administrative effort, consideration should be given to the cost effectiveness of redistribution.

When a redistribution is required, a CCC Redistribution Form must be completed for each transaction, by the cardholder or Card Administrator on a timely basis, and forwarded to the appropriate Local Charge Card Coordinator. The Local Charge Card Coordinator will redistribute the transaction in ***details*** **Online™** by entering the revised distribution number (i.e. Work Order, Project ID or OM&A Account/Cost Centre). CCC charges can only be redistributed using ***details*** **Online™** in the month of the purchase. The cut-off for redistribution in ***details*** **Online™** is the 27th of each month, at 6:00pm[1] . For Corporate Charge Card purposes a "month" is from the 28th of the previous month to the 27th of the next month. The redistribution form should be submitted to the Local Charge Card Coordinator for redistribution as close to the time of purchase as possible (a copy of the redistribution form should also be attached to the CCC statement). A copy of the CCC Redistribution Form can be found at the following link:

http://finance.hydroone.com/AccountsPayable/CorporateCard/document.htm

Receipts/supporting documents are **not** to be submitted to the Local Charge Card Coordinator with the redistribution form. Supporting documentation should be retained, and attached to the CCC statement that is submitted for review and authorization.

<u>Redistribution of Charges</u>

Where an item is to be redistributed from the default account established for that CCC, the account distribution number to which the charges are redistributed must be clearly identified on the redistribution form.

[1] There may be a few months during the year where there is an exception. Please check the Flat File Schedule from the Local Charge Card Coordinator (LCCC).

Redistribution of charges after the 27th of the month can be done directly in PassPort, or through a Peoplesoft General Ledger journal and should only be done when those charges are significant or material in value. In Passport, a redistribution is done by accessing the appropriate panels through the Payment Reference Number, and in so doing will revise at the Work Order level. Instructions for this process can be found at:

http://finance.hydroone.com/AccountsPayable/AcctgTools/document.htm

Alternatively, a redistribution can be processed through a journal in Peoplesoft General Ledger, in which case it will not be reflected in the PassPort Work Order. Business Units are responsible for processing any redistributions that are required. All CCC statements for which redistributions are required should be forwarded to the Local Charge Card Coordinator or the Finance contact, as appropriate, for journalizing. Redistributions of charges in Peoplesoft from one G/L account to another within the same cost centre should not be requested. If the line of business would like to process account redistributions, it is recommended they be done directly in PassPort.

4.7 Validation of Corporate Charge Card Transactions

Every charge that is incurred during the month will have an accounting distribution associated with it. The accounting distribution will be to either the Default Account associated with the card or the redistribution accounting of a particular transaction, processed in ***details*** **Online™** (i.e. Work Order, Project ID or OM&A /Cost Centre information entered to override the Default Account).

Each week, the Bank of Montreal (BMO) will validate the accounting distribution at the Card level or at the transaction level (where there has been redistribution) for the current month's transactions. To facilitate this validation on a weekly basis, Hydro One will provide a Chart of Accounts (which will contain the valid work orders, project IDs, accounts and cost centres) to the Bank of Montreal. Weekly Exception Reports and a monthly Overall Default Account Report will be issued by BMO to the LCCCs for their timely follow-up.

The objective of these control reports is to ensure that the corrective action indicated by the Weekly Exception Reports has been taken by the LCCC. This will ensure that there are few instances, if any, where the transactions are required to be posted to an overall default account, and that redistribution errors are minimal.

In the event that the default distribution on the Card or on a redistributed transaction does not validate using Hydro One Chart of Accounts, then the charge will default to an overall G/L default account (Cost Centre associated with the card and GLA 620280). If the cost centre does not validate, the cost centre will default to 7806. A G/L listing of these 620280 CC7806 transactions is sent on a monthly basis from Inergi to the applicable LCCC for corrective action.

Weekly Exception Report

On a **weekly** basis (every Wednesday), an **Exception Report** will be produced by BMO to identify the CCC transactions in which the CCC's default distribution number or the revised distribution number did not validate.

The report will group the information, according to the hierarchy within the BMO system, so that the Local Charge Card Coordinator can be advised of the problems for only those Cards that they support. Each Wednesday, the **Exception Report** will be forwarded by e-mail to the Local Charge Card Coordinator. LCCCs should endeavour to make corrections in a timely manner, to minimize problems at the end of the month when the CCC data is uploaded to Hydro One systems.

Monthly Overall Default Report

The business day following the 27th of each month, the CCC data will be extracted and a flat file created by BMO. The flatfile information is brought into PassPort electronically through the Accounts Payable module. The data is then available for viewing through other modules within PassPort (e.g. Work Management) and is passed to PeopleSoft for entry into the General Ledger in time for month-end reporting.

On a monthly basis, immediately after the monthly flatfile is created, BMO will produce a **Monthly Overall Default Report**. The report will identify the CCC transactions that did not pass the validation during the statement period's flatfile creation, resulting in the use of the overall default account in the creation of the flatfile. The report will group the information, according to the hierarchy, within ***details* Online™**, so that the Local Charge Card Coordinator can be advised of the overall defaulted accounting, for cards they administer. The **Overall Default Report** will be forwarded by e-mail to the appropriate Local Charge Card Coordinators for review and further handling as required. The LCCC must review the report with Line Management who will be responsible for advising if any corrective action should be taken.

Employee Information Validation

Certain information will be extracted from the bank's database and validated against the Hydro One employee database. This will ensure that all charges being processed are for current Hydro One employees only. The employee's ID number is the criteria that will be validated. Any exception (e.g. missing or invalid employee number, employee's status is inactive or there is no default account setup on the card) will be noted on the Employee ID/Default Report which is forwarded by Business Integration to the LCCCs for follow-up and resolution.

4.8 Payment Reconciliation Process

On a monthly basis a summary of all charges is sent from the Bank of Montreal to Accounts Payable for payment. One payment is made based on the details of all Hydro One CCC charges incurred. Prior to facilitating payment, the Corporate Charge Card Administrator will reconcile the transactions that were uploaded into PassPort, as per the control totals report produced at the time of upload, with the invoice as provided by the Bank of Montreal. Any exception will be followed up and reconciled prior to payment.

4.9 Management Reporting

***details* Online™** provides a suite of Management Reports to provide a control framework and to provide management information. A listing of some of the pre-formatted reports can be found in Appendix B. Specialized Reports can be developed at Line Management's request to meet any other reporting requirements they may have. Those needs should be identified to the LCCC.

Critical to the control environment at Hydro One, is the 1121D report. This report is a compulsory report that **MUST** be provided to the level of management responsible for the authorization of charge card expenses on a monthly basis (e.g. FLMs would be provided with a report for all the cardholders reporting to them). The 1121D report is distributed electronically to Supervisors by the Bank of Montreal on a monthly basis. The LCCCs also have the ability to download these reports from ***details* Online™**.

The 1121D report identifies employees with cards and employees who have been assigned a Work Order/Project ID/OM&A Account card. The two can be distinguished via the default distribution number (i.e. E for employee or OM&A account, W for Work Order, P for project ID cards). This report lists all open cards as well as any closed cards which have a billed balance in the month the report relates to. Closed cards could have pre-cancellation date transactions on them. Also, closed cards could possibly continue to incur charges even after the cancellation date, if these charges were pre-authorized (i.e. subscriptions, etc.). Particular attention should be paid to closed cards to ensure validity of transactions and that any necessary action is taken.

The following is a checklist of items to be reviewed:

Item Reviewed	Reviewed by	When reviewed	Reason for Review
Employees listed	Line Management	Monthly	To ensure employees are valid i.e report to a Supervisor and have valid card requirement
Current Month	Line Management	Monthly	To ensure statements have been submitted for monthly authorization
Credit Limit	Line Management	Periodically	To ensure limits reflect current needs of cardholder project or program
Cash Limit	Line Management	Periodically	To ensure limits reflect current needs of cardholder project or program
Default Account Code	Line Management	Periodically	To ensure appropriate default account is being utilized.

It is the responsibility of the Supervisor to ensure that statements are received in a timely manner, from each of the employees on the 1121D report who have a monthly balance, and that the statements are reviewed, approved and dated within 60 days of the statement date, and then forwarded in a timely manner to the LCCC for filing. Once the Supervisor has reviewed the 1121D report, it should be signed and dated, indicating approval, then forwarded in a timely manner to the LCCC for filing. Alternatively, approval can be provided electronically by sending the e-mail containing the 1121D report to the LCCC, indicating in the Subject line that the report has been reviewed and approved.

The retention period for this report is current year plus one.

Additional reporting needs should be identified to the LCCC.

4.10 Authority to Incur Expenses/Charges

Possession of a card does not imply authority to incur expenses, make purchases or make payments to vendors. Prior verbal approval, in accordance with Element 4, Material Requisition of the EAR/OARs, is required before any charges are incurred unless the charges represent business expenses that are a routine part of the job. Authorization after the expense has been incurred, in accordance with the EAR/OAR's, occurs via the CCC statement authorization process as outlined in Section 4.11 below.

The requestor of goods and/or services may not avoid the need for higher OAR authority approval levels by delegating these purchases to their subordinate. In the event that the expense is incurred by the subordinate, approval of the transaction or statement should be obtained by the requisitioner's supervisor.

4.11 Authorization Process

Each month the employee is required to submit their CCC statements, Cash Use and Employee Expense Reports to their Supervisor for authorization, in a timely manner. For Business Expense Cards, the statement is approved on a per transaction basis in accordance with Element 4, Invoice Approvals, of the OAR; and on the whole by the appropriate signing authority based on Guidance E of the OAR. For Work Order/Project/OM&A cards, the statement is approved on a per transaction basis in accordance with Element 4, Invoice Approvals, of the OAR. If a transaction(s) on the statement exceeds the signing authority of the approver, the statement should be forwarded to an individual with the appropriate authority under Element 4, Invoice Approval, of the OAR, to review and approve the transaction(s).

In the case of administrative staff, or any other staff who by the nature of their function make purchases on behalf of their Supervisor, statements should be approved by the immediate supervisor of his/her supervisor.

The appropriate signing authority level must sign and date the statement within 60 days of the statement date, as evidence of approval. Before approving a statement, the approver should ensure all responsibilities listed in section 4.20 are complied with.

The approval of the CCC statement, expense report or cash use form implies the approval of any exception to policies and procedures as indicated.
Approval of the CCC statement must be within 60 days of the statement date and be forwarded to the LCCC in a timely manner.

4.12 Closure of Work Order/Project ID/OM&A Account Cards

The life of a Work Order/Project ID card should generally correspond to the life of the Work Order or Project ID to which they are associated.

When a Work Order/Project ID is closed, the individual responsible for that card must notify the Local Charge Card Coordinator that the CCC should be closed.

When closing Work Orders/Project IDs, consideration should be given to the fact that the CCC transactions are not uploaded to PassPort until the 28th of each month. To ensure that all appropriate costs are charged against the Work Order/Project ID where a CCC is used, consideration should be given to leaving the Work Order /Project ID open, where there is a chance that there are applicable costs still to be processed through a CCC file.

The bank will automatically cancel any card where there has been no financial activity for a period of one year. A report providing the details of these account closures will be generated by the Bank and issued to the Barrie Administrative Service Centre (BASC) for follow-up with the appropriate Supervisors. These cards **cannot** be reactivated. If an individual for whom an inactive account was cancelled is deemed to have need of a CCC in the future, a new application is required. Cancelled cards will not be reissued on expiry.

4.13 Cash Withdrawals

The cash withdrawal option is available for all cardholders, where the feature has been authorized by Line Management in accordance with Guidance F of the EAR/OARs. It allows employees to be reimbursed for out-of-pocket expenses (e.g. mileage, parking, meals).

If there has been cash withdrawn during the month, the withdrawal is to be substantiated with a Cash Use Form. The Cash Use Form must be supported by original receipts for each purchase. The ATM withdrawal slip is not considered adequate supporting documentation for a withdrawal. While the ATM withdrawal slip is not required to support a cash withdrawal, it is a good business practice to secure the slip to confirm withdrawals on the CCC statement are valid. The Cash Use Form is available on the Accounts Payable website:

http://finance.hydroone.com/AccountsPayable/CorporateCard/document.htm

The above link must be referred to periodically to check for updates.

If an ATM is used, for convenience, the exact amount of cash used is not likely to be withdrawn. In this case there will be a balance (owed to Hydro One or owing to the employee) to be carried forward to the following month. This balance will be identified in the cash reconciliation on the top of the Cash Use Form. It will become the balance carried forward in the following month's Cash Use Form reconciliation. The balance being carried forward should be reasonable. This balance must be cleared out, to a reasonable amount, no later than year end, for the current year.

All Cash Use Forms must be signed and dated by the employee and must be approved by the appropriate supervisor.

All mileage distances claimed on the Cash Use Form must be verifiable. The business purpose and number of kilometers should be stated. Apply the per kilometer rate for the month the mileage expenses were incurred.

4.14 Cheque Writing Capability

Cheque writing capability enables the cardholder, where the functionality has been authorized in accordance with Guidance F of the EAR/OARs, to write cheques against their CCC. This feature exists primarily to allow the cardholder to issue cheques to subordinates to reimburse them for business expenses, where individuals have not been issued a CCC of their own. The cardholder of the account is the only one authorized to issue cheques for that card. Cheques may not be written to self or to "cash" to reimburse out of pocket expenses (use cash advances for this purpose).

If a vendor is not MasterCard enabled, and we expect to transact business with that vendor again, we should encourage the vendor to become a MasterCard merchant. Cardholders are encouraged to provide their LCCC with the vendor's details to facilitate setting them up on MasterCard. Until the vendor is MasterCard enabled, an appropriate Purchase Order should be set up via the Material Requisition process and invoices should be sent to Accounts Payable quoting the relevant Purchase Order number.

Where cardholders transact using a CCC cheque for transactions other than reimbursing subordinates for out of pocket, business expenses or other recognized reason; approval must be obtained from the Corporate Controller. Approval must be noted on the CCC statement. For example, if the payment is required immediately or Hydro One is at risk, a CCC cheque can be used. Detailed explanations as to why a CCC cheque was necessary must be provided if not a permitted circumstance.

Cheques are provided in duplicate. The duplicate copy of the cheque must be attached to the CCC statement for authorization along with any supporting documentation. A properly approved Expense Report must be included with all cheques written to reimburse employee expenses. The Expense Report is available on the Accounts Payable website:

http://finance.hydroone.com/AccountsPayable/FormsCabinet/Document.htm

In addition, the cardholder is responsible for providing the details of the cheque (i.e. payee, location/city, reason for payment) to their LCCC for input to ***details*** **Online™**. This enables analysis to occur of all CCC expenditures to ensure we realize all procurement benefits available to Hydro One.

Cheques are included as part of the monthly credit limit, and as such cheques can only be written up to the amount of the remaining credit limit. Since cheques accrue interest from the date they are cashed, consideration should be given to making cheques payable as closely as possible preceding the 27th. This will minimize the financing charges associated with cheques, similar to cash withdrawals.

4.15 Changes to Existing Corporate Charge Cards

From time to time, there will be requirements to change the information for existing cardholders. Those changes would include:

- Employees transferring in/out of business units;
- Changes to Credit/Cash Advance limits;
- Change in address;
- Change in default account (e.g. cost centre changes);
- Changes in organization structure;
- Addition/deletion of cheque writing capability; and
- Change to blocking requirements.

In each of these instances, the Local Charge Card Coordinator will process the completed Employee Change Form, available on the Accounts Payable website:

http://finance.hydroone.com/AccountsPayable/CorporateCard/document.htm

If the change relates to credit limits, cash advance limits, change to cheque writing capabilities or to blocking, it will require approval, in accordance with Guidance F of the EAR/OARs (see Section 4.4). The LCCC's will accept application changes via email providing the completed Employee Change Form is attached and the email is issued from the supervisor.

BMO will not process applications and changes >$50K or related to LCCC cards without first obtaining approval from the Corporate Charge Card Coordinator (CCCC) at the BASC. If there is a change in credit limit to $50,000+, the Change Form must also be faxed to the CCCC (at the BASC), who will provide authorization to BMO to proceed with the change. In addition, if a LCCC requests any changes to their own Corporate Charge Card, the change form must be approved by their Supervisor in accordance with the OAR and must additionally be sent to the Corporate Charge Card Coordinator for actioning.

4.16 Car Rental Insurance

Hydro One and the CCC offer Supplemental Liability Insurance and Collision Damage Waiver Insurance (CDWI), respectively; for vehicle rentals. These insurances must be **declined** when offered by the car rental agency, provided the car is being used for Hydro One business and has been rented using a Hydro One CCC. The car must be rented in the name of the cardholder and others should not be allowed to drive the vehicle, unless that person has been listed as a driver at the time of the vehicle rental. CDWI provides world-wide coverage and Supplemental Liability Insurance provides coverage in continental North America.

CDWI has certain exclusions and limitations (for more information refer to the link provided below). Notably, the insurance does not cover all categories of vehicles. For example, the following are NOT covered:

- Trucks, off-road vehicles, recreational vehicles, vans (except as further defined in coverage details)

http://finance.hydroone.com/AccountsPayable/CorporateCard/document.htm

The Employee Travel and Accommodations Policy provides further guidance on car rentals.

Hydro One's travel consultant will accept only the CCC for vehicle rentals.

4.17 Corporate Charge Card Support

As outlined in the authorization process described in Section 4.11, the cardholder must submit his/her CCC statement for approval on a timely basis. All expenditures on the CCC statement must be adequately supported. The requirement for support is as follows:

- All charges on the statement must be supported by the original receipt or invoice or other supporting document (where an invoice or receipt is not provided by the vendor) detailing the transaction. The copy of the charge card receipt alone is not adequate;
- Ensure the nature of the purchase, vendor name and amount is detailed on the receipt, invoice or supporting document;
- Provide the business purpose for each expense;
- For business meals and business entertainment, provide the number of participants and their names or group name;
- For amounts greater than $30, include adequate documentation to meet GST requirements. This usually means to provide the vendor's GST registration number and the GST amount, where reasonably available and where required;
- In limited circumstances, there may be exceptions to policies and procedures. These should be highlighted to assess and confirm whether the expenditure is a reasonable business expense;
- All cash withdrawals must be supported by the Cash Use Form;

- The Cash Use Form must comply with employee expense requirements as established in the Hydro One Employee Business Expense Procedure;
- All cheques must be supported with a copy of the cheque (the duplicate) and original related supporting documentation;
- Cheques written to reimburse employee expenses must be accompanied by an approved Expense Report, with original receipts, invoices or other supporting documentation (where a receipt or invoice was not provided by the vendor) for purchases attached, and;
- Redistribution form must be attached, where applicable.

4.18 Blocking and Enabling

As a standard, Hydro One has set a monthly credit limit requirement for all CCCs.

There are also a number of other blocking/enabling features that can be established on the CCC, at line management's discretion (e.g. transaction limits and Merchant Category Code blocking such as airlines, restaurants). Blocking prevents use of cards for those vendors or items/categories identified (e.g. accommodations only).

The blocking/enabling can be done on an individual card basis or on a group of cards. For a complete list of blocking/enabling options, refer to the Hydro One CCC Program Guidelines for Blocking, available on the Accounts Payable website:

http://finance.hydroone.com/AccountsPayable/CorporateCard/document.htm

When blocking/enabling cards, caution should be taken to ensure that it is not so restrictive that cards are inadvertently rejected for legitimate business use. For example, Business Depot processes all its transactions through the US parent company. Out of Country blocking would prevent use of the card at Business Depot. Similarly, Canadian Tire is considered a department store. If department stores were blocked, the CCC could not be used at Canadian Tire.

An alternative to blocking is exception reporting. Rather than block certain businesses, you may monitor monthly usage via exception reports from ***details* Online ™**, which will identify transactions in your business unit based on your selection criteria (see Exception Reporting).

4.19 Exception Reporting

Based on specified parameters, ***details* Online ™** provides Management with Exception Reporting capability. Exception reporting will be dictated by the selection criteria you request (e.g. transactions >$1,000 between May 1 and May 30 or cellular phone activity for a group of cardholders during a month).

There are also a variety of other reports available to Line Management. Some reports that management may find useful are reports:

- by vendor;
- by Merchant Category Code;
- by cardholder;
- by department; or
- by exception.

Reporting needs should be identified to your Local Charge Card Coordinator.

4.20 Responsibilities

<u>EMPLOYEE'S RESPONSIBILITIES</u>

1. Sign a Terms & Conditions form outlining the use of the CCC;
2. Use the Corporate Charge Card only for Hydro One business expenditures (both Travel and Expense), Local Purchasing or other spend types if appropriate, where authorized to do so;
3. Ensure that expenditures adhere to Local Purchasing Policies, Corporate Charge Card Procedures, Business Expense Procedures, Procurement Policy and Principles, Organization Authorities, and any other applicable policies, procedures and collective agreements;
4. Where the cardholder does not have authority to incur the expense, make the Local Purchase or make the payment, prior verbal approval must be obtained, in accordance with Element 4, Material Requisition of the EAR/OARs;
5. Ensure that the vendor is advised that invoices are not to be sent to Hydro One Accounts Payable for processing where payment is processed through the CCC;
6. Provide original vendor itemized receipt, invoice or other supporting documentation (where an invoice or receipt are not provided by the vendor) for each purchase;
7. Ensure the nature of the expense is detailed (vendor name and amount);
8. For business meals and business entertainment, indicate the number of participants and the names or the name of the group/Business Unit;
9. Provide the business purpose for each expenditure;
10. For amounts greater than $30, include adequate documentation to meet GST requirements. This usually means providing the vendor's GST registration number and GST amount, where reasonably available and where required;
11. In limited circumstances, there may be exceptions to policies and procedures. These should be highlighted to assess and confirm whether the expenditure is a reasonable business expense;
12. Verify the validity and accuracy of transactions billed to their Corporate Charge Card. In case of discrepancies, BMO permits a 90-day period to contest transactions. The cardholder should contact the vendor or the Bank and follow up to ensure corrective action has taken place;
13. Complete the Cash Use Form if there is any cash withdrawal. Ensure that original receipts, invoices or supporting documents (where an invoice or receipt is not provided by the vendor) are attached to the Cash Use Forms to substantiate the expenses, where appropriate;
14. Ensure that duplicate copies of the cheques <u>and</u> original receipt, invoice or supporting document (where an invoice or receipt is not provided by the vendor) are attached to the CCC statement for authorization;
15. Sign and date the Corporate Charge Card statement as verification that all expenses shown on the statement are accurate and reasonable business expenses incurred on behalf of Hydro One;
16. Ensure that redistribution forms, if necessary, are completed and forwarded to Local Charge Card Coordinators on a timely basis as required in accordance to the guidelines as established by Line Management, and that a copy of all redistribution forms are submitted with the CCC statement;
17. Ensure that monthly Corporate Charge Card statements are forwarded to the Supervisor in a timely manner;
18. Notify the Bank, Supervisor and Local Charge Card Coordinator, immediately if card is lost or stolen;
19. Notify LCCC if a change is required to the default distribution number on the CCC; and
20. Forward supporting documentation to the Card Administrator, when using a Work Order/Project ID/OM&A account CCC that is issued in someone else's name.

CARD ADMINISTRATOR'S RESPONSIBILITIES

1. All the responsibilities listed under Employee's responsibilities;
2. Ensure that the Corporate Charge Card, its number and expiry date as well as MasterCard Cheques (if applicable), are appropriately safeguarded notifying only those employees that need to know the number (in the case of a Work Order/Project ID/OM&A Card); and
3. Ensure that all original receipts, invoices or other supporting documentation (where a receipt or invoice was not provided by the vendor) issued to other authorized users of the Work Order/Project ID/OM&A Account card are forwarded to you on a timely basis.

SUPERVISOR'S/APPROVING AUTHORITY'S RESPONSIBILITIES

1. Approve credit and cash limits in accordance with Guidance F of the EAR/OARs;
2. Ensure CCC statements are signed and dated by the employee;
3. Ensure that the expenses are reasonable and comply with applicable policies, procedures and collective agreements;
4. Ensure that all Corporate Charge Card statements are received, where there has been activity in the month, as identified by the 1121D Report;
5. Ensure that all expenses on the Corporate Charge Card statement, including cheques and cash withdrawals, are appropriately supported and are reasonable and represent business expenses, incurred on behalf of Hydro One;
6. Ensure where required, the Cash Use Form and the CCC statement or Expense Report is completed, dated and signed by the employee, and the cash withdrawal balance carried forward agrees with the closing balance for the previous month;
7. Ensure each expenditure on the CCC statement, Cash Use Form and Expense Report (where applicable) is supported by the original receipt, invoice or other supporting documentation (where an invoice or receipt was not provided by the vendor), the business purpose and the required GST information;
8. Ensure that redistribution has occurred where appropriate, in accordance with guidelines established with respect to redistribution by the Business Unit, and that the appropriate redistribution forms are part of the supporting documentation submitted with the CCC Statement;
9. Approve each transaction in accordance with Element 4, Invoice Approval, of the EAR/OAR. For Business Expense Cards, approve the cumulative total of the expenditures for the month, in accordance with Guidance F of the EAR/OAR. Refer to section 4.11;
10. Within 60 days of the statement date, sign and date the statement as to the fact that it has been reviewed and complies with items 1 through 9;
11. Ensure that the Corporate Charge Card statements are sent to the BASC for filing;
12. Ensure that all employees using a Work Order/Project ID/OM&A Account card sign a Terms & Conditions form;
13. Notify Local Charge Card Coordinator immediately when an employee is terminated or when a card should be cancelled;
14. Notify the LCCC if a change is required in the default distribution number on a CCC;
15. Review the 1121D report on a monthly basis to ensure that statements have been submitted for monthly authorization, the details for the cardholders identified on the report are complete and accurate, the credit and cash limits are reasonable and commensurate with the position or Work Order/Project ID/OM&A Account that the card is associated with, and that the default account distribution number is accurate; and
16. Corporate Charge Card Coordinator is advised immediately when a Local Charge Card Coordinator is terminated or has been transferred.

LOCAL CHARGE CARD COORDINATOR'S RESPONSIBILITIES

1. Ensure that the monthly 1121D reports are reviewed with evidence of approval and are filed on a timely basis;
2. Ensure card applications are completed accurately and are signed by the Supervisor;
3. Ensure each card application is accompanied by a Terms & Conditions form signed by the employee;
4. Ensure that all signed applications and change forms are appropriately filed;
5. Enter cardholder information into ***details*** **Online ™** based on approved card applications and/or change applications;
6. Once the CCC has been issued for a new account, enter the default account and employee ID for the new card in ***details*** **Online ™**;
7. Ensure that redistribution forms received from cardholders are entered into ***details*** **Online ™** in the current month;
8. Ensure any journals required to transfer costs incurred on a Corporate Charge Card are processed on a timely basis;
9. Ensure all CCC cheque information is input into ***details*** **Online ™** on a timely basis;
10. Ensure all approved statements are received and are filed and kept for 7 years (a statutory requirement under tax legislation);
11. Review all CCC statements for completeness (signed and dated, approval date within 60 days of statement date) and presence of supporting documentation;
12. Provide statement specific compliance reporting to cardholders;
13. Ensure weekly Exception Reports and monthly Overall Default Report from the Bank are reviewed and appropriate action taken on a timely basis (these should be signed, dated and filed by the LCCC);
14. Where issued to an LCCC, ensure that the G/L Account (7806) Default Report and Employee ID/Default Report from Business Process Improvement are reviewed and appropriate action taken;
15. Request reports from the Bank to meet the needs of Supervisors and approving authorities;
16. Ensure effective follow up on non-employee active cards; and
17. Monitor the effective follow up of Closed Report items.

CORPORATE CHARGE CARD CO-ORDINATOR'S (CCCC) RESPONSIBILITIES

1. Supervise and administer work of centralized LCCC's;
2. Provide training for all LCCC's as required. Maintain LCCC procedural manual as required, jointly with Supply Chain Services;
3. Communicate procedural changes and other CCC related information to LCCC's, as required; and
4. Develop and manage control reports and communicate results to address key risks.

CORPORATE CHARGE CARD ADMINISTRATOR

1. Reconcile monthly BMO invoice to data file (for upload to ERP system); and
2. Manage reporting structure for Bank system.

CORPORATE FINANCE/INERGI/BUSINESS INTEGRATION RESPONSIBILITIES

1. Develop and perform compliance tests to address risks; and
2. On a monthly basis, provide applicable LCCCs with Employee ID/Default Report and G/L Account (7806) Default Report.

SUPPLY CHAIN SERVICES RESPONSIBILITIES

1. Review the ***details*** **Online™** database to collect information on vendors and negotiate preferred pricing contracts where appropriate;
2. Facilitate the review of CCC spending and credit limit utilization;
3. Perform analysis of CCC issuer reports to mitigate risk; and
4. Review and provide recommendations to Corporate Controller for updates to all relevant procedures and policies as well as periodic corporate communications (used to highlight specific aspects of any relevant policies or procedures).

4.21 Fraudulent Use of the Corporate Charge Card

If you suspect misuse or abuse of the CCC, you should notify your Supervisor immediately. Supervisors are required to contact Corporate Audit and Corporate Security immediately, so that the incident can be investigated. Corporate Audit/Corporate Security will contact the AP Manager where investigations require vendor contact/information.

Misuse or abuse of the use of the CCC could lead to disciplinary action up to and including dismissal.

If charges are made against your card, which you did not personally incur or authorize someone else to incur (for Work Order/Project ID/OM&A Account cards), the bank should be notified immediately. The Bank of Montreal will launch an investigation. If Hydro One is found not to be negligent, with respect to the incurrence of the transaction, Hydro One will not be held financially responsible for the transaction, and the transaction will be reversed off the cardholder's statement.

4.22 Inadvertent Personal Use of the Corporate Charge Card

If the CCC is used for personal expenses in error, the expense must be re-paid immediately. Repayment can occur by making a payment against the CCC at any MasterCard bank or through a reduction of the amount to be reimbursed on the Cash Use Form.

If repayment is made through the bank, the original bank receipt for repayment must be obtained and attached to the CCC statement that is sent to the Supervisor (with an explanation). A copy of the bank receipt for repayment should be kept for the cardholder's personal records.

If you have a Cash Use Form that is to be sent in within a reasonable amount of time from the date of the personal purchase, the amount may be deducted from the Cash Use Form. It must be clearly identified on the Cash Use Form that it is a reimbursement for personal expenses. In either case, the personal purchase should be **clearly** identified on the CCC statement. **Personal cheques to Hydro One for reimbursement of the CCC for personal expenses are not to be used**, as this method does not provide for an adequate audit trail of the repayment, nor does it ensure that the proper accounts are appropriately reversed.

5.0 Auditing Requirements

Reimbursement to or charges by employees for travel and other business-related expenses are subject to examination by internal and external auditors, including Canada Revenue Agency. In addition, Hydro One may also review these charges for compliance with policies and procedures. Reimbursed or charged expenses found unreasonable or not properly supported could be disallowed by the Canada Revenue Agency and deemed to be taxable benefits to be included as compensation to the employee. The final responsibility for satisfying the Canada Revenue Agency that all such expenses are strictly work related and are not personal in nature rests with the employee and Supervisor.

If expenses have been paid by Hydro One and are subsequently found not to be in compliance with this or other applicable policies and procedures, the employee will be required to repay such amounts. In addition, the employee and the approving Supervisor may be subject to disciplinary procedures. In particular, for the employee, non-compliance with policy and procedure such as discrepancies and inappropriate or duplicate claims could lead to disciplinary action up to and including termination.

6.0 Associated Policies & Procedures

- Employee Business Expense Procedure
- Employee Travel and Accommodations Policy
- Policy on Corporate Vehicles Assignment to Hydro One Staff
- Organizational Authority Register And Executive Authority Register
- Code of Business Conduct for Employees
- Bank of Montreal Local Coordinator's Manual
- Hydro One MasterCard Corporate Card Cardholder's Guide
- Local Charge Card Coordinators Procedures
- Local Purchasing Definition
- Local Contractor & Material Purchase Process
- Procurement Policy and Principles
- Local Purchase Procedure

Appendix A: Accounting & Capitalization Treatment of Corporate Charge Card Transactions

PROJECT ID CORPORATE CHARGE CARD

A Corporate Charge Card can be set up to default its accounting to a PeopleSoft Project ID, if Line Management determines that the accumulation of the Corporate Charge Card costs is appropriate at the Project ID level, to meet the business needs.

The type of costs, their materiality, and acceptability of the use of allocations of accumulated costs are factors that may impact Line Management's decision to have a card issued at the Project ID Level.

For a "Capital" Project ID

Hydro One's capitalization rules, within PeopleSoft must be considered in determining if the accumulation of costs at the Project level is appropriate (see Capitalization Guidelines).

For an "OM&A" or "OMASP" Project ID

For an "OM&A" or "OMASP" Project ID, the Business Unit must determine what level of accuracy for accounting allocation is required.

To use a Project ID as the Default Account on a Corporate Charge Card (CCC) or as the re-distributed accounting on a particular CCC transaction:

- The PROJECT ID in PeopleSoft must have a status of "O" (i.e. Open), as at the end of the fiscal month that the CCC transaction(s) is/are to be posted to it, through PassPort's AP module. If the status is NOT "O" then the particular PROJECT ID will not be extracted and forwarded to the Bank of Montreal (BMO) for CCC transaction validation purposes.
- The PROJECT ID in PeopleSoft must not exceed 9 digits.
- The PROJECT ID must not have one of the following project types: SUM, GL, SLA, AW, CONV, CONVH, CONVX

Given a "valid" Project ID, on the basis of the above criteria- the following will be applicable:

- The PROJECT MANAGER or DEPT ID from PeopleSoft, for a particular PROJECT ID, will be used as the "Cost Centre Charge" within PassPort - to which the CCC transactions will be posted.

  NOTE: The "Dept ID" in PeopleSoft is equal to the "Cost Centre" in PassPort.

- Each CCC transaction will have a Detailed Cost Element (DCE) attached to it based on a mapping of a DCE to the Vendor's Merchant Category Code (MCC). An MCC is assigned to each MasterCard vendor based on the Vendor's type of goods or services (e.g. MCC 5812 - Eating Places, Restaurants - so DCE 406 - Meals has been mapped to it).

- The first digit of the DCE (i.e. the Resource Type) will dictate the transaction's final accounting, done in PeopleSoft, based on the PROJECT ID's Project Type, in PeopleSoft, and the applicable Accounting Template.

- The CCC costs can be seen at the Project ID / Cost Centre in PeopleSoft only (i.e. Project ID costs cannot be viewed in PassPort through any particular panel, as that module is not being used by Hydro One).

The Default Account on a Project Card would be set up as follows:

Where the PROJECT ID is 123PROJ (status is open, project type is not one of the exceptions) and the DEPT ID that is to be used is 0850.

NOTE: Project ID can be alphanumeric; but where the Project ID is less than the full 9 digits, " * " must be used as placeholders for the number of digits less than 9 that the Project ID is.

P123PROJ**0850 (the font differences are for emphasis only)

WORK ORDER CORPORATE CHARGE CARD
(For those Groups that use PassPort's Work Management)

A Corporate Charge Card can be set up to default its accounting to a PassPort Work Order (Task 01), if Line Management determines that the accumulation of the corporate charge card costs is more appropriate at the work order level, to meet the business needs.

For a "Capital" Project ID

Hydro One's capitalization rules, within PeopleSoft must be considered in determining if the accumulation of costs at the Project level is appropriate (see Capitalization Guidelines).

For an "OM&A" or "OMASP" Project ID

For an "OM&A" or "OMASP" Project ID, the Business Unit must determine what level of accuracy for accounting allocation is required.

To use a Work Order (Task 01) as the Default Account on a Corporate Charge Card (CCC) or as the re-distributed accounting on a particular CCC transaction:

- The PROJECT ID in PeopleSoft, related to the WORK ORDER of the transaction must have a status of "O" (i.e. Open), as at the end of the fiscal month that the CCC transaction(s) is/are to be posted to it, through PassPort's AP module. If the status is NOT "O" then the particular PROJECT ID's WORK ORDERs in PassPort will not be extracted and forwarded to the Bank of Montreal for CCC transaction validation purposes.

  The CCC transaction will always be posted against **TASK 01** of the WORK ORDER.

  Consequently, the status of the particular WORK ORDER (Task 01) must be one of the following values, for that WORK ORDER to be extracted and forwarded to the Bank of Montreal for CCC transaction validation purposes:

Status	Description
30	APPROVED
45	READY
48	WORKING
49	H/OPS
50	FINISHED
85	COMPLETE
90	CXCL/REQ
92	CXCL/DNY

Given a "valid" Project ID and Work Order (Task 01), on the basis of the above - the following will be applicable:

- The COST CENTRE CHARGE attributable to TASK 01 in PassPort will be the used as the "Cost Centre Charge" within the AP module of PassPort - to which the CCC transactions will be posted. Costs will also go to the PassPort Activity and PassPort Job Type for Task 01.

- Each CCC transaction will have a Detailed Cost Element (DCE) attached to it based on a mapping of a DCE to the Vendor's Merchant Category Code (MCC). An MCC is assigned to each MasterCard vendor based on the Vendor's type of goods or services (e.g. MCC 5812 - Eating Places, Restaurants - so DCE 406 - Meals has been mapped to it).
- The first digit of the DCE (i.e. the Resource Type) will dictate the transaction's final accounting, done in PeopleSoft, based on the Work Order's related PROJECT ID's Project Type, in PeopleSoft, and the applicable Accounting Template.

The Default Account on a Work Order Card would be setup as follows:

- Where the Work Order is 14000 (status is 30), Cost Center of Task 01 is 0850.
    - **NOTE:** A PassPort Work Order number is stored as an 8 digit number. When using the WO module in PassPort, the system will allow you to enter only the significant digits, leaving off the three leading zeros in this instance. However, when entering the WO information into the AP module it is necessary to enter the leading zeros; therefore for purposes of the Default Account / Re-distribution, the leading zeros MUST be entered.

W000140000850 (the font differences are for emphasis only)

EXPENSE CORPORATE CHARGE CARD (Directly Charged to an OM&A Account)

A Corporate Charge Card can be set up to default its accounting directly to an OM&A Account and Cost Centre, if Line Management determines that the accumulation of the corporate charge card costs is appropriate at that level, to meet the business needs.

NOTE: There are only certain OM&A Accounts that can be used for these cards, as there are limitations as to what type of goods/services can be acquired and paid using the Corporate Charge Card (i.e. what constitutes local purchasing).

Corporate Charge Cards provided to Employees for business expenses would be examples of an OM&A Account and Cost Centre card. Another example, would be a card issued for a Department's or Business Unit's Postage or Courier Costs or General Administrative Costs.

To use an OM&A Account and Cost Centre as the Default Account on a Corporate Charge Card (CCC) or as the re-distributed accounting on a particular CCC transaction:

- The ACCOUNT must be a legitimate PassPort/PeopleSoft Account number and in the 610000 - 629999 inclusive range to be allowable for CCC transaction validation purposes

  (**Note:** GLA 280000 is also a legitimate number for validation purposes). For example, GLA 228000 - INVENTORY would NOT be allowable, as the CCC is not to be used to acquire Inventory.

- Additionally, the COST CENTRE CHARGE must be a valid Cost Centre (from PeopleSoft) which would have been extracted and forwarded to the Bank of Montreal for CCC transaction validation purposes.

Given a "valid" Account and Cost Centre, on the basis of the above - the following will be applicable:

- Each CCC transaction will have a Detailed Cost Element (DCE) attached to it based on a mapping of a DCE to the Vendor's Merchant Category Code (MCC). An MCC is assigned to each MasterCard vendor based on the Vendor's type of goods or services (e.g. MCC 5812 - Eating Places, Restaurants - so DCE 406 - Meals has been mapped to it).

The Default Account on an OM&A Account Card would be setup as follows:

- Where the Account is 620280 (a valid Account in PassPort and within the allowable inclusive range), Cost Center of 0850.

E**620280**0850 (the font differences are for emphasis only)

CORPORATE CHARGE CARD - CAPITALIZATION GUIDELINES

<u>Corporate Charge Card at PROJECT ID Level</u>

If CCC costs are posted to the Project ID level, these costs will come in as Activity - General, to PeopleSoft, and will be treated as an overhead and will be allocated based on the allocation of the direct costs parameters of the automated Capitalization Process, in PeopleSoft.
If the CCC costs are of a significant value and need to be allocated to a specific Project ID - Activity (which would be the PassPort Work Order number) re-distribution within PeopleSoft's Project Costing to the appropriate activity can be requested.

<u>Corporate Charge Card at PassPort WORK ORDER Level</u>

For "Blanket" Capital Projects (e.g. New Customer Connects) and "ACTIV" Capital Projects (e.g. Damage Claims)

1. If CCC costs are posted to a single PassPort Work Order for the Zone/Territory Blanket Project ID, the work group for this Work Order should be Head Office. In this way, all of the CCC costs are treated as an overhead and will be allocated by the Capitalization Process, in PeopleSoft, to the PassPort Work Orders associated with the Project ID.
2. If CCC costs are posted to a single PassPort Work Order for <u>each Work Group within the Zone/Territory</u> Capital Project (Blanket/ACTIV), the work group for the Work Order should be the one to which it applies. In this way all CCC costs are treated as an overhead and will be allocated by the Capitalization Process, in PeopleSoft, only to the related PassPort Work Orders for that work group.
3. If the CCC cost is of a significant dollar value and needs to be charged to at the Work Order level then use one of the following:

    a. Use a CCC that has been issued for the specific PassPort Work Order;
    b. Use the Project ID card that the Work Order is related to and request that a re-distribution be done of the particular CCC transaction, by the Local Charge Card Coordinator, through the Bank of Montreal's ***details*** **Online™** system; or

Assuming that the transaction has been posted already in PassPort, process a journal entry within PeopleSoft, under the related Project ID with the appropriate PeopleSoft Activity number (which would be the PassPort Work Order Number).

<u>Corporate Charge Card at PassPort WORK ORDER Level</u>

For "Normal" Capital Projects (e.g. non Blanket)

- If CCC costs are posted to a PassPort Work Order (that has a one-to-one or many-to-one WO to Project ID relationship) then a CCC is required for each Work Order and for each Work Order the CCC costs will accumulate at Task 01. In this way all CCC costs will be allocated by the Capitalization Process, in PeopleSoft, based on direct costs in each work order for the job type of Task 01.

Appendix B: Management Reports from *details* Online™

All of the following reports are available for your organization unit:

1.	Detail Transaction Report	Provides information about purchase transactions for a specific period of time.
2.	Transaction Line Item Detail Report	Displays detailed transaction information for purchases with line item information for a specific period of time. The transactions are grouped by account number and transaction and are sorted by accounted number, transaction processing date etc…
3.	Cardholder Account Statement	Displays basic information for a given account (looks like a corporate charge card statement).
4.	Cash Advance Transaction Report	Displays cash advance for specific time period.
5.	Merchant Category Code Transaction Report	Displays information by merchant category code (e.g. hotels, restaurants, airlines) for a specific period.

If you identify a need for a report that is not specified, customized reports can be developed to meet your needs. You should address these requests through your Local Charge Card Coordinator.

Appendix C: DCEs

DCE	DCE Title	Description
211	Construct	Construction & Production Material
231	Fuel & Lubr	Fuel & Lubricant
320	Consult	Consultant/Rental
321	Consultant	Consultant
331	Other Ext	Other External Costs
400	Misc.	Miscellaneous
401	Insurance	Insurance Costs
402	Printing	Printing & Related
403	Computer	Computer Services
404	Freight	Freight Costs
405	Travel	Travel Costs
406	Meals	Meals
407	Empl/Reloc	Employee Relocation
408	Courses	Courses and Conferences
409	License	License Fees
411	Compsoft	Computer Software
412	Compequip	Computer Equipment
420	Space	Space & Facility Costs
421	Telephone	Telephone Costs
423	Telecommun	Telecommunications
424	Facil. Oth	Facilities Costs - Other
425	Leases	Leases
426	Utilities	Utilities
FFF	Fuel & Lubr	Fuel & Lubricants
PPP	Proc & Misc	Procurement Card & Miscellaneous

Appendix D: Corporate Charge Card Usage by Non-Hydro One Employees

SUPERVISOR TERMS AND CONDITIONS

The following describes the Hydro One Terms and Conditions that govern the use of the Corporate Charge Card (CCC) by non-Hydro One employees to conduct business on behalf of Hydro One.

By approving a Hydro One corporate credit card to non-Hydro One employees, thereby signed, the Hydro One Supervisor is responsible for all Hydro One credit card transactions incurred by the approved non-Hydro One personnel. Where there are disputed transactions, thereby named, the Hydro One Supervisor assumes full responsibility to resolve such issues and to ensure a final settlement favourable to Hydro One. In addition, it is the Supervisor's duty to follow Hydro One policies and procedures and clearly inform non-Hydro One personnel holding an active Hydro One Corporate Charge Card about terms and conditions that govern Hydro One corporate card usage. Supervisors must also ensure that the non-Hydro One employee has signed a "Hydro One Corporate Charge Card Cardholder Terms and Conditions".

Supervisors are also responsible for:

- notifying the Bank and Local Charge Card Coordinator of lost/stolen cards and changes in cardholder data;
- complying with Corporate Purchasing guidelines and procedures, Business Expense Procedure, Corporate Charge Card Procedure and Local Purchasing guidelines governing the use of Corporate Charge Cards;
- verifying and signing-off to signify the validity of billed transactions on the monthly transaction statements;
- take necessary action to resolve disputed transactions as detailed below;
- request all supporting documentation to transaction statements, provide supporting documentation for audit purposes
- ensure proper completion of Cash Use Form which provides adequate explanations for all cash withdrawals;
- where a cheque has been issued, ensuring a duplicate copy of the cheque is being provided with the statement.
- approval of re-distribution forms and advising the Local Charge Card Coordinator of any re-distribution of charges required for transactions.

Corporate Charge Card transactions are:

- approved in accordance with Corporate Employee Business Expense Procedure and Local Purchasing policy. Prior approvals must be sought for purchases or payments in accordance with Element 4, Material Requisition, of the EAR/OARs; and
- governed by a monthly card limit.

The Corporate Charge Card Number is confidential and is to be used exclusively for purchases made on behalf of Hydro One. If there is a problem with a Statement of Account, Cardholders should follow-up first with the merchant if a bill transaction amount is in dispute. If the dispute is still unresolved, the Supervisor should report the dispute within 30 days of the statement date to the Bank of Montreal.

I have read all the above and agree to adhere to these terms and conditions	
Signature	**Printed Name**
Employee Number	**Date**
Approved Non Hydro One Personnel for Hydro One Corporate Card Usage:	
Printed Name	**MasterCard #**
Company Name/Affiliation:	

Appendix E: Document Management

Owner/Functional Responsibility	Supply Chain Management
Approval Date	March 2008
Approval Required By	VP, Supply Chain Services
Effective Date	March 2008
Document Last Reviewed	March 2008

Filed: December 23, 2008
EB-2008-0272
Exhibit I-8-1
Attachment 4

HODS

Document Number: **SP 0705 R1**

Document Name: **Employee Business Expense Procedure**

Issue Date: **November 2008**

When in printed form, this document is uncontrolled.
It is the user's responsibility to verify that this copy matches the document on the Hods website.

The requirements of this document are mandatory.

Purpose

This document describes the procedure for incurring, submitting, processing, and approving employee business expenses.

Revision

The following changes have been made:

- Update to procedure for processing and reimbursement of business expenses for employees without a Corporate Charge Card.
- Recent changes related to the booking of business travel utilizing the Corporate Commodity Contract.
- Clarification of currency with respect to daily meal limits when travelling in the United States.
- Clarification on the documentation requirement regarding business meals and entertainment.
- References to SP0895 Board and Executive Travel Policy.

Contents

1.0 Scope

This procedure specifies the requirements applying to the following:

- the incurrence of employee business expenses;
- the processing and submission of employee business expenses including supporting documentation;
- review and approval processes for employee business expenses ; and
- accountabilities of employees, supervisors and financial staff involved in the processes.

2.0 Definition

Employee Business Expenses: Expenses including compensatory expenses incurred by employees in the course of performing their job. Compensatory expenses are out-of-pocket expenditures reimbursed at prescribed rates, e.g. mileage. Employee business expenses do not include expenses that are typically reimbursed through the Pay System, such as extramural training, moving expenses, pay allowances (e.g. instructor's bonus), relief pay, service duty, standby allowance, safety boots/tools/clothing (for unionized employees), Occupational Vision Plan (for safety eye glasses), etc.

3.0 Governing Principles

a. No employee shall be out-of-pocket because of travel or other expenses necessarily incurred in the conduct of Hydro One business. An employee should not profit financially from assignments and shall be accountable for exercising due diligence, integrity, prudence and judgment in incurring business expenditures.

b. Corporate Charge Cards shall be provided to employees who frequently incur business expenses such as hotel costs, meals and mileage. Corporate Charge Cards will be the preferred medium of payment using any one of the available options described in Corporate Charge Card procedures. Employees are not to use Corporate Charge Cards or business expense reports for personal expenses.

c. Employees cannot approve their own expenses and allowances. Expense report submissions must be approved by a person higher in the direct line of authority with sufficient authority under the Organizational Authority Register. Employees shall obtain appropriate verbal approval before incurring expenses, unless such expenses are a routine part of the job.

   Tip: In order to avoid approving your own expenses, use the general guideline: *the most senior employee pays*. This may not always be practical in situations such as the examples below:

   i. a business meeting or event for employees hosted by a group where more senior employees have been invited
   ii. a working lunch hosted/organized by a group where more senior employees have been invited to take part.

d. Approval of Administrative Assistants business expenses will be carried out by the superior of his/her immediate supervisor.

e. In limited circumstances where there may be exceptions to policies and procedures, these should be highlighted to assess and confirm whether the expenditure is a reasonable business expense. The approval of the statement implies the approval of the exceptions to polices and procedures as indicated.

f. Subject to the exception described in section 6.0 where a supervisor reimburses a subordinate who has not been assigned a Corporate Charge Card, reimbursement of employee business expenses will be limited to those incurred by the employee and not by other employees.

g. All expenses must comply with relevant policies and procedures (see Appendix B - References).

4.0 Guidelines

4.1 Examples Of Acceptable And Unacceptable Expenses

a. **Examples of acceptable expenses:**

Expenses incurred in the conduct of Hydro One business and within policy constraints including dollar limits as applicable and may include:

- Parking
- Cellular/blackberry and long distance telephone calls
- Travel and accommodation (see 4.2)
- Meals and entertainment (see 4.3)
- Automobile mileage (see 4.2)
- Office supplies
- Seminars and conferences

b. **Examples of unacceptable expenses:**

Expenses unrelated to Hydro One business or inconsistent with other policy constraints:

- Expenses incurred by one employee (e.g. hotel room) should not be charged on another employee's charge card.
- Spouse's expenses, e.g. airfare, meals, cost difference if any between single and double lodging.
- Expenses which would have been incurred as a normal activity by an employee, e.g. lunch while at their normal place of business.
- Personal, non business-related entertainment and similar expenses incurred while traveling on company business.
- Taxable and non-taxable benefits, which are administered via the pay system, e.g. tool allowance, incentives or rewards, entitlements for safety boots/tools/clothing (for unionized employees) and glasses.
- Purchases administered via other company plans such as safety glasses through the Occupational Vision Plan, medical, dental (see Human Resource Procedures).
- Items which are more properly recorded through other financial processes, in particular, minor fixed asset purchases which exceed $2K per unit.

4.2 Travel And Accommodation

a. Business travel outside Canada and the United States must receive authorization from the President and CEO. For out-of-province travel within Canada and travel within the United States, approval is required from a Vice President or above. All other travel is approved in accordance with the Organizational Authority Register.

b. The following criteria govern travel arrangements:

- All air travel will be arranged utilizing the Corporate Commodity Contract, except for emergency situations or where approved by the supervisor.

  [**Note:** if the rate being quoted does not appear to be the most competitive rate, bring it to the attention of the agent or contact the manager of the Corporate Commodity Contract within supply chain if necessary.]

- The following constraints apply:
  - Air travel will be economy class, or its equivalent with respect to cost, unless otherwise approved by the President and CEO.
  - Rail travel may be first class.
  - Car rentals will be small or intermediate size unless otherwise approved by Manager level or above.
  - All air travel will be based on the lowest negotiated rate as offered by the Corporate Commodity Contract that accommodates the traveling employee's schedule and circumstances.
  - Senior Management of Hydro One Inc. at or above the Vice-President level should also consult SP 0895 Board and Executive Travel Policy for further guidance.
- For guidance on insurance protection and liability coverage for car rentals, the Employee Travel and Accommodations Policy and the MasterCard Corporate Card Cardholder's Guide should be referenced.
- Where the employee has obtained authority to make their own travel arrangements, the Business Unit shall pay the lesser of:

  the employee's actual out-of-pocket expenditures related to company business (including mileage) supported by appropriate receipts (for air travel the receipt should be the ticket voucher)
  OR
  the lowest cost which Hydro One would have incurred had the Business Unit arranged the travel, as defined above that accommodates the traveling employees schedule and circumstances. Employees will not be allowed to claim the cash equivalent of airfare when using another mode of transportation.

- When making travel arrangements outside of the Corporate Commodity Contract, it shall be at the lowest cost that accommodates the traveling employee's schedule.

c. Employees driving their own automobiles on company business must ensure compliance with corporate policy, which identifies when it might be preferable for Hydro One to assign a corporate vehicle. They must also disclose using their vehicle for Hydro One business to their insurer, and carry insurance of not less than **$1,000,000** inclusive, covering public liability and property damage.

<u>Note</u> that $1,000,000 coverage is mandatory for Society and PWU employees effective January 1, 2001 as a result of arbitrated settlement.

4.3 Business Meals And Business Entertainment

The following are conditions under which Hydro One will pay for an employee's meal expense:

- it is specified by a collective agreement;
- the employee is dining with a non-Hydro One employee and conducting Hydro One business;
- the employee is dining with another employee and is conducting Hydro One business;
- refreshments and catering for business meetings; or,
- as a result of Hydro One business the employee purchases a meal that would not have been purchased otherwise.

[To avoid approving your own expenses, refer to the guiding principles in section 3.0 (c).]

Total meal costs per person per day should be reasonable as determined by their supervisor and/or their collective agreement. Meal costs not covered by a collective agreement will, depending on the circumstances, generally be regarded as being reasonable if within the following limits:

Business Travel:

- Travel within Canada - daily meal costs for travel within Canada should not exceed $60 per day excluding tax and gratuities (e.g. Breakfast - $12; Lunch - $18; Dinner - $30).
- Travel within the U.S. - daily meal costs for travel within the U.S. should not exceed US$75 per day excluding tax and gratuities (e.g. Breakfast - US$15; Lunch - US$20; Dinner - US$40).
- Travel outside Canada and the U.S. - should be reasonable in the circumstances and approved by your supervisor.

The above limits are suggested guidelines only and do not replace the requirement that the costs be reasonable. Daily meal costs exceeding the above limits should be supported by adequate business circumstances and approved by your supervisor.

You should not charge for meals covered by a hotel where you are staying or are included in the registration fee for a seminar or conference that you are attending.

Internal Functions:

Businesses/functions are permitted to hold internal team functions. Managers and business heads must use discretion concerning the number of internal functions held in a year. Summarized below are the guidelines for events of this nature.

- Up to $30 per employee, excluding tax and gratuities, for lunch
- Up to $60 per employee, excluding tax and gratuities, for dinner

The above limits are suggested guidelines only and do not replace the requirement that the costs be reasonable. Meal costs exceeding the above limits should be supported by adequate business circumstances and approved by your supervisor.

[To avoid approving your own expenses, refer to the guiding principles in section 3.0 (c).]

Business Entertainment:

An employee's responsibilities may require that they entertain for business purposes (e.g. external customers, vendors or business associates to establish and maintain business relationships). All expenses of this nature must be reasonable in the circumstances, be supported by appropriate receipts, and must have a business purpose.

[To avoid approving your own expenses, refer to the guiding principles in section 3.0 (c).]

4.4 Recognition To Employees

Managers will on occasion recognize an employee for an outstanding achievement or effort, special occasions, special achievements, etc. Such recognition should be reasonable in the circumstances and commensurate with accomplishment. Recognition will generally be considered to be reasonable if the total cost is within the following limits:

- Up to $50 per employee excluding taxes if applicable, commensurate with the accomplishment, special event or achievement
- Up to $30, excluding taxes and gratuities, per person for lunch
- Up to $60, excluding taxes and gratuities, per person for dinner

Please note that these are guidelines and not restrictive thresholds. In certain circumstances (e.g. exceptional achievement) the above limits can be exceeded if approved by the President and Chief Executive Officer ("CEO") or the Chair in the case of the CEO. Management is encouraged to use discretion.

It should be noted that all cash or near-cash gifts (e.g. gift certificate) are taxable and should be reported to payroll for inclusion in the employee's T4. Corporate Tax will be able to advise you regarding the tax status of non-cash gifts to employees.

4.5 Cellular/Blackberry Local And Long Distance Calls

Cellular phones and blackberries are provided to employees for business purposes. The assigned plan should be appropriate for but not exceed the specific business requirements of the employee. Limited and reasonable personal use is permitted.

The employee must reimburse Hydro One for any costs incurred as a result of personal use of cellular phones and blackberries that is beyond limited and reasonable use.

4.6 Payments In Non-Canadian Currencies

An employee who has a cash advance or Charge Card withdrawal in Canadian funds and subsequently converts the funds to a non-Canadian currency for foreign business expenditures must translate the foreign business expenditures to Canadian dollars using the original conversion rate.

5.0 Auditing Requirements

Reimbursement to or charges by employees for travel and other business-related expenses are subject to examination by internal and external auditors, including the CRA (Revenue Canada). In addition, Hydro One may also review these charges for compliance with policies and procedures.

Reimbursed or charged expenses found unreasonable or not properly supported could be disallowed by the CRA (Revenue Canada) and deemed to be taxable benefits to be included as compensation to the employee. The final responsibility for satisfying the CRA (Revenue Canada) that all such expenses are strictly work related and are not personal in nature rests with the employee.

If expenses have been paid by Hydro One and are subsequently found not to be in compliance with this or other policies and procedures, the employee will be required to repay such amounts. In addition, the employee and the approving supervisor may be subject to disciplinary procedures. In particular, for the employee, non-compliance with policy and procedure including discrepancies and inappropriate or duplicate claims may lead to discipline up to and including termination.

6.0 Employee Expense Reports

Employee business expenses can be processed through the Corporate Charge Card. This could occur in one of several ways:

- Cash withdrawal feature on Corporate Charge Card (CCC) assigned to the employee who incurred the expense.
- Supervisor uses cash withdrawal feature on their card to reimburse a subordinate employee who does not have a CCC assigned to them.
- Supervisor uses MasterCard cheque writing feature on their card to reimburse a subordinate employee who does not have a CCC assigned to them.

Use of a Corporate Charge Card for employee expenses is strongly urged to reduce company administration costs and to provide the fastest form of reimbursement to the employee. Detailed guidelines for Corporate Charge Card use are outlined in the Corporate Charge Card procedure.

Expense report procedures are summarized below for non-Corporate Charge Card users. When using the expense report procedures, employees are encouraged to submit their expenses monthly. However, where the out of pocket expenses are sizable, more frequent reimbursement may be desirable.

6.1 Employee's Responsibilities

- Ensure that expenditures made have prior verbal approval unless the expenditure represents business expenses that are a routine part of the job, and are consistent with applicable Hydro One policies and practices and applicable collective agreements (see Appendix B - References).
- Exercise integrity, prudence and judgment in incurring their business expenditures.
- Submit expenses within a reasonable time period, e.g. monthly.
- Use the appropriate form and provide the information required on the form. In particular, business purpose for the expenses must be stated. Where expenses cover other people, evidence necessary to satisfy supervisor approval is required. Evidence necessary should be pre-established with

supervisor and may include specific names, the Company name (external to the Hydro One affiliates) or a descriptor (where confidentiality is required) and business purpose of the expense.
- Provide original receipt, invoice or other supporting documentation (where an invoice or receipt is not provided by the vendor) for each purchase.
- Ensure the nature of the purchase, vendor name, and amount is detailed.
- Provide the business purpose for each expense.
- For business meals and business entertainment, provide the number of participants and identify the group of individuals attending, or the name of each individual attending.
- For amounts greater than $30.00 provide adequate documentation to meet GST requirements. This usually means to provide the receipt with the vendor's GST registration number and GST amount, where reasonably available and where required.
- In April 2003, Hydro One eliminated use of the G-Permit. Therefore, employees should ensure that the vendor charges PST where applicable, even if the vendor has previously been issued a Hydro One G-Permit Tax Certificate.
- For air travel, the appropriate receipt is the e-ticket or e-invoice.
- Sign the expense report as verification that the submission is accurate and the expenses are reasonable business expenses incurred on behalf of Hydro One.
- Cash expense report cheques as soon as possible after receipt to avoid the risk of loss or theft.
- Expense report summaries should be totaled such that it is easy to agree expenses to the corporate card totals.

6.2 Supervisor's Responsibilities

- Ensure applicable policies and procedures governing employee business expenses are reviewed with their direct reports and other subordinate staff
- Ensure that the expenses are reasonable and consistent with policies and procedures (see Appendix B - References) and applicable collective agreements.
- Ensure all expenses were incurred to conduct Hydro One business.
- Ensure the employee has completed the expense report or cash use form accurately, documented the business purpose for expenses, assigned the correct charge number(s), attached required supporting documents, provided the required information, and has signed and dated the corporate charge card statement, cash use form or expense report.
- Approve within signing authority in accordance with the organizational authority register.

Appendix A: Submitting Expense Reports

Employees who do not have a Corporate Charge Card and have incurred business expenses must complete an Expense Report as follows:

1. Complete the Hydro One expense report form, including header information and report number.

2. List expenses, indicate business purpose for expenditure and attach original receipts, invoices or other supporting document (where an invoice or receipt is not provided by the vendor) to support expense. For amounts greater than $30.00 provide adequate documentation to meet GST requirements. This usually means to provide the vendor's GST registration number and GST amount, where reasonably available and where required.

3. Sign and date the form as verification that submission is accurate and that the expense is a reasonable business expense incurred on behalf of Hydro One. (See Hydro One Admin Procedure, Employee Business Expenses, Section 5.0 - Auditing Requirements).

4. Submit the form and supporting receipts/documentation to supervisor for review and approval.

Supervisor writes a Corporate Charge Card cheque to reimburse employee for the approved business expenses upon review and approval of the expense report.

[Refer to the SP0706 R0 Corporate Charge Card Procedure for requirements on supporting documentation when writing a Corporate Charge Card cheque.]

Appendix B: References

- SP0772 - Employee Travel and Accommodations Policy
- SP0708 - Procurement Policy
- SP0826 - Procurement Procedure
- Organizational Authority Registers and Executive Authority Register
- Code of Conduct for Employees
- Corporate Vehicle Policy
- SP0706 - Corporate Charge Card Procedure
- SP 0895 - Board and Executive Travel Policy
- Collective Agreements
- Power Workers Union
- Society of Energy Professionals
- Electrical Power Systems Construction Association (EPSCA) & Canadian Union of Skilled Workers (CUSW)

Appendix C: Document Management

Owner/Functional Responsibility	Finance
Approval Date	Approved by Chief Financial Officer in October 2008
Approval Required By	Chief Financial Officer
Effective Date	October 2008
Document Last Reviewed	November 2008

HODS

Document Number: **SP 0704 R0**

Document Name: **Employee Business Expense Policy**

Issue Date: **April 2008**

When in printed form, this document is uncontrolled.
It is the user's responsibility to verify that this copy matches the document on the Hods website.

The requirements of this document are mandatory.

Purpose

This document describes the policy for incurring, submitting, and approving employee business expenses.

Revision

This is a new document.

Contents

1.0 Policy Statement

1. No employee shall be out-of-pocket because of travel or expenses necessarily incurred in the conduct of authorized business of Hydro One or its business units.

2. Employees shall be accountable for exercising integrity, prudence and judgment in the business expenditures.

3. Corporate credit cards ("CCC") shall be provided only to employees where the cost of control and residual risk is less than the advantage to be achieved from their use.

2.0 Corporate Requirements

1. Employees shall obtain approval from the appropriate authority to incur travel and other business expenses (*see policy on Employee Travel and Accommodations*), except where approval is inherent in the approved budget or authorized work assignments that require these employees to incur business expenses, or it is inherent in their positions (e.g., routine travel between Hydro locations).

2. In authorizing proposed employee business expenses, the appropriate authority shall ensure that the expenditures have a business purpose and are reasonable.

3. The following criteria govern the payment of employee business expenses:

- No employee is to approve his/her own expenses, rather, such approval must be provided by a person higher in the direct line of authority with sufficient authority under the Organizational Authority Register.
- Subject to the exception described where a supervisor uses either the cash withdrawal or MasterCard cheque writing feature of the CCC to reimburse a subordinate employee who does not have a CCC, (see section 6.0 of the Employee Business Expenses Administrative Procedure), reimbursement of employee business expenses will be limited to those incurred by the employee and not by other employees.
- The claims are to have adequate documentation and meet GST requirements.

3.0 Specific Circumstances

1. Approval of the business expenses of the Chair of the Board will be carried out by the Chair of the Audit and Finance Committee, subsequent to a review by the Chief Financial Officer.

2. Approval of the business expenses of the President and Chief Executive Officer will be carried out by the Chair of the Board, or if not available the Chair of the Audit and Finance Committee.

3. A summary of all business expenses incurred by the Chair of the Board and the President and Chief Executive Officer and their Administrative Assistants will be prepared by the Chief Financial Officer and be presented to the Audit and Finance Committee for review semiannually.

4. All Direct Reports to the President and Chief Executive Officer will submit business expenses to the President and Chief Executive Officer for review and approval.

5. Approval of Administrative Assistants expenses will be carried out by the supervisor of his/her immediate supervisor.

6. When an employee uses the CCC to pay for business expenses, approval of the monthly statements containing the expenses is required by a person higher in his/her direct line of authority with sufficient authority under the Organization Authority Register. As a guiding principle, the most senior employee pays.

7. All programs for the issue of corporate credit cards and working fund advances shall provide Hydro One with adequate protection against losses stemming from unauthorized use of such credit cards and funds or from abuse or negligence in their use by employees holding them.

8. On an annual basis the external auditors will examine and review the business expenditures of the Chair of the Board, the President and Chief Executive Officer, the Chief Financial Officer, the General Counsel, one other Direct Report to the President and Chief Executive Officer at their discretion and their administrative assistants. The external auditors will summarize their findings and present them to the Audit and Finance Committee.

Appendix A: References

- Refer to SP 0772 Employee Travel and Accommodations Policy for travel principles and requirements.
- Refer to the Corporate Administrative Procedure SP 0705 Employee Business Expenses for guidelines, auditing requirements and employee expense report responsibilities.

Appendix B: Document Management

Owner/Functional Responsibility	Finance
Approval Date	Approved by Board of Directors on February 1, 2007
Approval Required By	Board of Directors
Effective Date	February 1, 2007
Document Last Reviewed	March 2008

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Document Number: **SP 0772 R0**

Document Name: **Employee Travel and Accommodations Policy**

Issue Date: **November 2008**

The requirements of this document are mandatory.

Purpose

This document describes the policy for incurring and approving employee travel and accommodation expenses.

Revision

This document has been revised for recent changes related to the booking of business travel utilizing the Corporate Commodity Contract and references are made to SP0895 Board and Executive Travel Policy.

Contents

1.0 Summary

This policy applies to all employees traveling on business for Hydro One. This policy applies to travel accommodation and associated travel expenses (not including expense accounts).

2.0 Governing Policy

Employees will travel on Hydro One business in the most cost-effective manner.

3.0 Principles Application Rules

1. All air travel will be arranged utilizing the Corporate Commodity Contract. Employees may only arrange their air travel outside of the Corporate Commodity Contract in emergency situations or where

approved by supervisor. Corporate Officers will have access to the services provided by a personal travel counselor as designated by the travel company. The personal travel counselors will assist in meeting the specific travel and accommodation needs of the Corporate Officers.

2. Frequent travelers may file a profile with the travel company indicating specific travel and accommodation needs. The Traveler Profile must be approved by the employee's supervisor (minimum Director level), subject to the constraints below, and filed with the company. Consideration may be given in the following situations/circumstances: length of flight/rail trip, destination (i.e. North American vs. Inter-continental destinations), height and weight of employee, travel habits, position, etc.
3. Consideration may be given for upgrades of car rentals based on number of passengers, type and amount of travel estimated (i.e. Highway vs. local), weather conditions (i.e. Winter vs. summer), etc. Refer to the constraints below.
4. Business travel outside Canada and the United States must receive approval from the President and CEO. For out-of-province travel within Canada and travel within the United States, approval is required from a Vice-President or above.
5. All travel (air, rail or car rentals) and accommodation must be paid for using the Corporate Procurement Card where available.
6. The following constraints apply:
    - Air travel will be economy class, or its equivalent with respect to cost, unless otherwise approved by the President and CEO.
    - Rail travel may be first class.
    - Car rentals will be small or intermediate size unless otherwise approved by Manager level or above.
    - All accommodations will be based on the lowest negotiated rate as offered by the Corporate Commodity Contract that accommodates the traveling employees schedule and circumstances.
    - Senior Management of Hydro One Inc. at or above the Vice-President level should also consult SP 0895 Board and Executive Travel Policy for further guidance.
7. The number of employees travelling should be minimized and limited to where the Corporation will clearly derive a benefit.
8. Employees must minimize travel and living costs by exercising cost consciousness. Employees are expected to exercise tight control on travel and expenses and should exercise restraints as with personal funds. Employees must not profit financially from any transaction made while travelling on Hydro One business.
9. Employees must provide as much notice as possible when making travel arrangements to achieve maximum cost savings. In the event of changes in travel plans, employees must ensure that all travel arrangements are revised to ensure that Hydro One does not incur unnecessary cost.
10. Employees are to decline Collision Damage Waiver Insurance (CDWI) and Supplemental Liability Insurance provided the vehicle is being used for Hydro One business and has been rented using the Hydro One CCC. The vehicle must be rented in the name of the cardholder and others should not be allowed to drive the vehicle unless that person has been listed as a driver at the time of the vehicle rental. Employees who do not have a Corporate Charge Card and who are paying for vehicle rentals by cash or personal credit card should purchase Collision Damage Waiver Insurance.
11. Employees may retain credits from frequent traveler programs. However, travel plans, selection of airline, routing requirements, etc. must not result in additional expense nor require an increase in travel time. Employees may use credits from frequent traveler programs to upgrade on services providing there is no additional cost to Hydro One.

4.0 Best Practices

The following best practices should be followed when making travel arrangements:

- Consider alternatives to minimize travel costs (i.e. Teleconferencing)
- Purchase tickets in advance for best fare
- Consider, where practical, alternative itineraries (e.g. Overnight stays, different departure/arrival times) to obtain lower fares

- Minimize costs by returning rental cars with a full tank of gas
- Public transportation or taxis may be a lower cost alternative to car rentals
- Hotel and airport shuttle services are to be used where practical

Appendix A: References

Refer to the SP 0704 - Employee Business Expense Policy
Refer to the SP 0706 - Corporate Charge Card Procedure
Refer to the SP 0895 – Board and Executive Travel Policy

Appendix B: Document Management

Owner/Functional Responsibility	Finance
Approval Date	October 2008
Approval Required By	Executive Committee
Effective Date	October 2008
Document Last Reviewed	November 2008

HYDRO ONE
ADMINISTRATIVE PROCEDURES

Section: **Business Process Improvement**	*Issue Date: January 2007*
Subject: **MAJOR FIXED ASSETS RETIREMENT/SURPLUS REPORTING PROCEDURES**	*Review Date*: *September 2007*
	Prepared by: Sam Amodeo *Submitted by: Deborah Hardy*
	Number: H1- -BI-BPI-A-C-R01 Rev No.: 000

Section: **Business Process Improvement**	*Issue Date: January 2007*
Subject:	*Review Date: September 2007*
MAJOR FIXED ASSETS RETIREMENT/SURPLUS REPORTING PROCEDURES	*Prepared by: Sam Amodeo* *Submitted by: Deborah Hardy*
	Number: H1- -BI-BPI-A-C-R01 Rev No.: 000

1.0 Purpose

The purpose of this document is to outline the steps required to retire from service assets by way of either Sell, Scrap & Sell or Return to Inventory . These assets and profiles are recorded in the Asset Management System by original year of installation.

2.0 Governing Principle

Accurate record keeping with respect to the installation and retirements of assets, or the portions of assets known as profiles, must be consistently maintained in order to satisfy depreciation, financial, sales, tax and regulatory requirements. This necessitates that capital assets and capital profiles retired from service are accurately tracked in the fixed assets records, and removal costs appropriately charged to depreciation expense – adjustment account.

In the event of the Surplusing/Sale(Disposition code "S") or Regular Retirement/Scrapping of an asset(Disposition code "X") the Retirement/Surplus Declaration must be completed as per Inergi LP - Investment Recovery and Fixed Asset procedures also in accordance with Element 6.0 of Hydro One's Organizational Authority Register (OAR).

If an asset is retired but deemed to be re-useable it is returned to inventory and a Retirement form must be filled out with disposition code "I" and submitted. (refers to reusable DX Transformers process)

If an asset is taken out of service to be sent to CMS no retirement form is necessary however a Material Transfer Form must be completed and submitted.

Section: **Business Process Improvement**	*Issue Date: January 2007*
Subject: **MAJOR FIXED ASSETS RETIREMENT/SURPLUS REPORTING PROCEDURES**	*Review Date*: *September 2007*
	Prepared by: Sam Amodeo *Submitted by: Deborah Hardy*
	Number: H1- -BI-BPI-A-C-R01 Rev No.: 000

3.0 Scope

This document describes the Retirement and Surplus process associated with major fixed assets, identifying responsibilities for reporting and recording the retirement of these assets in different situations. Additionally, it details the criteria for completing the Retirement/Surplus Form for all Hydro One business units, and outlines requirements for valuation of assets and profiles that have been declared surplus.

All service providers of all business units involved in the retirement of assets and/or declaring assets and associated profiles surplus are required to adhere to the procedures outlined in this document.

Minor Fixed Assets (MFA), and refurbishment work that is considered OM&A in nature (i.e. the work being done to merely maintain the existing life expectancy of the asset), are not addressed in this procedure.

4.0 Definitions

APPROVER - as per Hydro One OAR 6.0, the person who has the authority to declare a piece of equipment (profile) surplus. Although this authority would normally rest with Asset Management, authority to approve the surplus of assets as part of a Capital project or program is delegated (either explicitly or implicitly) to the Service Provider as part of the "Release of Work" process. Note: Fixed Asset Unit of Inergi LP will not verify name as being 'authorized', in accordance to Hydro One's OAR. It is Hydro One's responsibility to ensure compliance through audit processes for each business unit.

MAJOR FIXED ASSET- comprise power system facilities for electrical generation, transmission, transformation and distribution, communication facilities, production facilities and administrative & service buildings.

MINOR FIXED ASSETS- comprise low value capital assets that are generally portable and which generally contribute indirect net economic benefits to the corporation.

BLANKET PROJECT- distribution capital project type set for monthly automatic capitalization (usually defined as 'day jobs' - i.e. pole replacement, service upgrades etc)

BUSINESS UNITS - DX (220), TX (210), TELE (510), OGRC (650)

CAPITAL PROFILES - unit(s) of equipment that make up an asset (i.e. poles, transformers etc).

IN-SERVICE REPORT PACKAGE - a set of forms that are required by Finance when declaring a parent asset is operational and an asset is being retired or surplused. These packages are normally completed by technical people in the field and approved by the Project Manager, Business Manager or UTS.

MATERIAL TRANSFER FORM - a form required by Finance when transferring an asset to CMS with pre-selected profiles that require a 'TO' and 'FROM' parent asset ids. Note: Only those profiles on form are required.

NET BOOK VALUE/CAPITAL VALUE - NBV is the capital value less the accumulated depreciation; capital value is the cost of original installation

PARENT ASSET - location or specific property unit(s) that provides economic benefit (i.e. John TS, or a line section)

POOLED ASSET - also known as system reserve. These are not available for the general construction (i.e. not-consumable inventory), but are capitalized when purchased.

REFURBISHMENT WORK- work that is capital in nature involves either the replacement of components representing Plant Retirement Units or a betterment of an asset.

RETIREMENT - the process that removes a capital profile from the parent asset when the piece of equipment has been taken out of service.

SURPLUS - the disposition of a specific piece of equipment when that equipment is no longer required by Hydro One,(Sale of asset).

VALUATION - the current value of a parent asset/profile for a specific vintage

VINTAGE - year of installation

DISPOSITION CODE – code on the retirement/Surplus form which identifies the action to be taken, see codes below:
List of retirement (disposition) codes:

- S - Sold (Retirement &Declaration of Surplus)
- X – Scrapped (Retirement & Declaration of Surplus)
- I – Return to Inventory(Retirement, mainly Provincial Lines Transformers)

Note: If the asset is being sent to CMS, no retirement form is completed instead a Material Transfer Form is completed.

5.0 Retirement & Surplus Reporting

Retirement Overview

Replacement of retired assets or profiles is accompanied with the setting up of a capital project to track all costs associated with the process of declaring the replacement asset or profile in-service. Once the capital

project is completed, and the asset is put into service, the Project Manager must ensure the completion of an In-Service Package which contain the forms necessary to retire the old and register the new profiles through a series of system interfaces.
Note: Provincial Lines process differs in that the "In Service" portion is automated, however the retirement/surplus form is not and is sent directly to Fixed Asset Unit of Inergi LP.

The retirement accounting process consists of the capital being credited out of the asset and into the accumulated depreciation account. The net book value (NBV) would remain intact until fully depreciated. Where no vintage is indicated (original install date), Fixed Asset Unit will use the FIFO method, (the oldest instance of the profile will be retired).

Declaration of Surplus Overview
Assets or profiles may be deemed redundant to the needs of an organizational unit due to plant changes, obsolescence, work order cancellations, over ordering or economic conditions. In such instances, the assets or profiles are categorized as being declared surplus. If the Project Manager determines that the surplus assets or profiles are to be scrapped or sold, then the Surplus side of the Retirement/Surplus Form must be completed to ensure proper disposal by the Investment Recovery Unit of Inergi LP.

The surplus accounting process consists of writing off the NBV of the asset sold once the sale is final. Where no vintage is indicated (original install date), Fixed Asset Unit will use the FIFO method, (the oldest instance of the profile will be retired).

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	Prepared by: Sam Amodeo *Submitted by: Deborah Hardy*
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5.1 Retirement/Surplus Form

A Retirement/Surplus Form, containing a list of profiles that are relevant to particular business units, is completed by the Project Manager/Business Manager or UTS for all capital projects that satisfy either or both of the following criteria:

- If an **estimated** labour cost for the removal of the asset or profile is established at the time the project is set-up, regardless of whether the estimated labour was incurred as part of the removal cost
- An **actual** piece of equipment (profile) is removed.

If the capital project for replacement of retired profiles is considered a Blanket Project (see definition in 4.0), an In-Service Package is **<u>not</u>** required but a Retirement/Surplus Form is required to be completed in it's entirety, see the link to the forms below:
http://operations.hydroonenetworks.com/web/root/bi-bpi_assets.htm

The Retirement/Surplus Form is sent to the Fixed Asset Unit of Inergi if completed as a single document(Provincial Lines), if it is completed as part of the In-Service package(REIS) the REIS is sent to Program Results for review and they send it on to Project Costing Unit of Inergi for processing.(see matrix in 5.2)

Email: Project Costing Finance or Program Results (Text Signed from email address of approver)
Internal mail or fax(must be signed): TCT12 Project Costing Unit or Program Results
Contact Program Results(Hydro One) or Project Costing(Inergi) if help is required in completing the forms.

5.2Tasks and Responsibilities

Project Managers/Business Managers/UTS of all Service Providers

_In order to ensure Investment Recovery disposes of the Assets to be taken out of service on a timely basis the Retirement/Surplus form must be completed and submitted as soon as the Capital Replacement Project begins. (No Retirement/Surplus form, No pickup)

- The Project Manager ensures the completion of the retirement and surplus side of the form if the asset is being scrapped or sold and completes only the retirement side if the asset is being returned to inventory(reusable DX transformers). Submits the form to Fixed Asset Unit- Inergi
- The form will have to be submitted again with the REIS package once the asset is in service and the project is complete, with the exception of "Provincial Lines" as the REIS is automated and therefore the accounting is completed upon the first submission of the retirement form.
- The Project Manager must provide either a quantity or an estimate of the current replacement value of the item(s) being removed for all items identified on the Retirement/Surplus form where no units of measurement are available (e.g. misc. station equipment). This is necessary to allow the Fixed Asset Unit to calculate the net book value of the retired items.See Definitions 4.0 for disposition codes and other fields within the form that are required. Contact Program Results(Hydro One) or Project Costing(Inergi) if help is required in completing the forms
- Completes an analysis of any hazardous material such as oil in transformers which requires special dismantling, and attaches it to the Retirement/Surplus Form (see Hazardous Waste Procedures).

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- Attaches the completed and approved Retirement/Surplus Form to the In-Service Package when the project is deemed in-service, except in the case of Provincial Lines in that the Retirement/Surplus form would be all that is needed, and sends to Program Results who after there review forward to the Project Costing Unit of Inergi LP. For blanket projects, Provincial Lines, Telecom and Remotes forward the Retirement/Surplus Form directly to the Fixed Asset Unit of Inergi LP.
- The Project Manager will be contacted by Investment Recovery to arrange for the pick up of assets.

See below Retirement/Surplus Form Responsibility Matrices for each LOB:

<u>Provincial Lines</u>

<u>Activity</u>	<u>Close Work Order</u>	<u>Complete Retirement/Surplus form</u>	<u>Approve Retirement/Surplus form</u>	<u>Send to Inergi</u>
1. Project/Prog Work	FBC (Planning Group)	Field	Scrap -Business Manager Sale – per OAR	FBC
2. Demand(N-Connect, upgrades)	BASC	Field	Scrap - UTS Sale – per OAR	BASC
3. Reactive Work(trouble calls, storm, damage)	FBC (Planning Group)	FBC (Planning Group)	Scrap- Business Manager Sale – per OAR	FBC

<u>Grid Operations</u>

<u>Activity</u>	<u>Close Work Order</u>	<u>Complete Retirement/Surplus form</u>	<u>Approve Retirement/Surplus form</u>	<u>Send to Program Results*</u>
1. Project/Prog Work	Field Staff	Field Staff	Scrap -Project Manager- Sale – per OAR	Project Manager

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E&CS

Activity	Close Work Order	Complete Retirement/Surplus form	Approve Retirement/Surplus form	Send to Program Results*
1. Project/Prog Work	Project Accounting Specialist	Project Accounting Specialist	Scrap - Project Manager Sale – per OAR	Project Manager

Remotes

Activity	Close Work Order	Complete Retirement/Surplus form	Approve Retirement/Surplus form	Send to Project Costing-Inergi
1. Project/Prog Work	Project Engineer	Project Engineer	Scrap – Project Manager Sale – per OAR	Project Manager

* - Program Results reviews and then sends to Inergi- Project Costing/Fixed Assets.

**Note – If the asset is being sent to CMS no retirement form is needed, a Material Transfer Form is completed and sent to the Fixed Asset Unit(Inergi).*

Fixed Asset/Project Costing Units of Inergi LP

Retirement/Surplus Forms prior to REIS

Once the approved Retirement/Surplus form is received in advance of the REIS the Fixed Asset Unit will perform the following:

- Reviews the form for completeness
- Completes the valuations of the parent asset and profile(s) where applicable(disposition code X or S, with the exception of Provincial Lines) and forwards to Investment Recovery with a copy to the requestor. No accounting for the retirement is completed unless

disposition code I is requested or the Retirement/Surplus form is from Provincial Lines regardless of the disposition code.

- A log of all valuation requests will be kept in a computer file in the Fixed Asset Unit.
  The log will contain:
  - date of request
  - requestor's name
  - a brief description.
  - Project ID
  - Asset ID
  - Asset Profile
  - LOB
  - Valuation
  - Invoiced or Outstanding(Code S)

- Reviews the required additional information on the Retirement/Surplus Form if a blanket project.

- Fixed Asset Unit will return the Retirement/Surplus Form to the Project Manager/ or Program Results for corrective action if the Form is incomplete.

<u>Retirement/Surplus Forms with REIS</u>
Once REIS package is verified the Project Costing Unit processes the "In Service" portion and forwards a copy of the package to the Fixed Asset Unit to process the retirement of the profiles indicated on the Retirement/Surplus form depending on Disposition Code which is traced back to the Valuation Log if necessary . The Fixed Asset Unit will:

- Checks the Retirement/Surplus Form for completeness:

  - profiles, asset id
  - Capital Project ID(Work Order if applicable)

  - quantity, vintage
  - disposition code of 'S' or “X”

- Reviews the copy of the In-Service Package received from the Project Costing Unit, or an email of the Retirement/Surplus form if the project is a blanket, as well as the valuation logs to ensure compliance of valuation requests.

- Processes the retirement of the parent asset or profile when the REIS package is received containing the Retirement/Surplus form if applicable.
- Returns the Retirement/Surplus Form to the Project Manager or Program Results for corrective action, if the information is incomplete.

If Assets are being sent to CMS the Material Transfer Form must be completed and submitted by the Project Manager and will be processed by the Fixed Asset Unit, transferring the asset to CMS(no retirement done)

Investment Recovery Unit(IR)

- Once IR receives the valuation of assets to be Straight Sold(not scrapped and sold), they need to approve the sale(per the OAR) and inform/copy Inergi(Fixed Asset Unit) so they can write off the asset once the invoice is generated. If the asset is being scrapped they do not have to inform the Fixed Asset Unit.
- Investment Recovery will then sell the asset and send the invoice to Inergi(Fixed Asset Unit) so that they can clear the valuation log which contains a log of all assets where a valuation was completed (Disposition Code S or X)

Note: IR will not arrange for pick up of any assets or scrap that has not been approved and accompany paperwork. IR will keep a log of assets approved to be picked up from Retirement/Surplus forms forwarded to them from the Fixed Asset Unit.

6.0 Specific Circumstances - Retirements of Refurbishment Work, System Reserve, Strategic Spare Parts and Distribution Transformers

6.1 Refurbishment Work

Refurbishment work that is capital in nature involves either the replacement of component representing Plant Retirement Units(PRU) or a betterment of an asset.

When assets or profiles are removed from service for refurbishment work, decisions are made regarding the refurbishment work and the treatment of the repaired profiles.(See Refurbishment Procedures – BPI Website) The table identifies the specific scenarios, and the decisions respecting completion of a Retirement/Surplus Form.

Scenario	**Retirement/Surplus Form**
1. To be reinstalled into service	N/A
2. To be returned to consumable inventory for reuse	Yes
3. To be scrapped/sold	Yes
4. To be returned to CMS Inventory(Operating Spares & Strategic Parts)	No (Material Transfer form)

6.2 System Reserve

System Reserves are known as 'operating spares' and consists of large complete units on hand in the event of a system failure. These units are usually major equipment items such as power transformers, circuit breakers, mobile unit substations etc. The units are either purchased or used items. They are capitalized as a 'pooled asset' and not recorded as inventory. When put into service as replacement for a retired asset, the NBV of the unit is transferred from the system reserve parent asset to the in-service asset by Fixed Assets Unit and no Retirement/Surplus Form is required. However, a Material Transfer Form is required and to be completed by the Project Manager.

6.3 Strategic Spare Parts

Strategic spare parts are not 'whole units' and thus are treated as inventory. From an operational point of view, these parts should be managed with the requirements of Hydro One in respect to its inventory regulations. The costs are charged to the capital project (assuming refurbishment) and **no Retirement/Surplus Form is required.**

6.4 Distribution Transformers (customer upgrades)

Distribution transformers, removed from service specifically for customer upgrades, are either sent back to inventory, to another site, or scrapped. Transformers that are deemed reusable are returned to inventory 'like new' to be subsequently issued for use at another location. In most cases the determining factor as to whether the transformer is scrapped or returned to inventory is based on the vintage, 1981 and prior(scrapped), post 1981 returned to inventory, this is due to the PCB content in transformers 1981 and earlier.

For Network Services, Remotes and any other area of business, the unit removed from service will be input to the inventory account (Passport) at the average unit cost, with the offsetting credit charged to a special capital 'holding' project (one for each zone). A Retirement/Surplus form is required with the disposition code being "I"(return to inventory), the Fixed Asset Unit will write off the NBV of the asset with the offsetting debit charged to the same project as the credit from the input to inventory. The balance in the project (if any) will be allocated to capitalization each month.

For more information regarding the disposition on DX customer related transformers for Networks, please see web site:
http://operations.hydroonenetworks.com/web/root/bi-bpi_assets.htm

7.0 Special Retirements

The sudden loss of a parent asset due to 'Acts of God' such as fires, ice storms, hurricanes, floods or earthquakes are considered 'special' retirements. These 'special retirements' shall be approved by Corporate Finance on materiality bases and once approved, Fixed Asset Unit of Inergi LP will retire all affected profiles within that parent asset on a pro rated basis. Since special retirements occur very infrequently and are handled at the corporate level, **no Retirement/Surplus Form is required.**

8.0 Special Circumstance - Inactive Asset (obsolete)

For 100% retirement of a parent asset where asset (site) is deemed 'inactive' (obsolete, or no longer operational), a valuation must be completed for item(s) deemed surplus and the appropriate checkbox marked on the Retirement/Surplus Form. All other profiles that exist in the parent asset will be automatically retired and need not be indicated on the Form.

9.0 Local Sale of Surplus Goods

Under no circumstances does anyone or any Line of Business have authority to sell a Major Fixed Asset without the involvement of IR using the proper company procedures outlined in this document.

10.0 Contacts

Inergi LP - Project Costing Finance (email)
Inergi LP - Investment Recovery (Declaration of Surplus)
- Richard Rumney - 416-904-6931

11.0 References, Forms & Web Sites

"Retirement Surplus Package.xls" "Material Transfer form.xls" "In Service Package 2004.xls" "Capitalization Procedure REV 1_20

Section: **Business Process Improvement**	*Issue Date: January 2007*
Subject:	*Review Date*: *September 2007*
MAJOR FIXED ASSETS RETIREMENT/SURPLUS REPORTING PROCEDURES	*Prepared by: Sam Amodeo* *Submitted by: Deborah Hardy*
	Number: H1- -BI-BPI-A-C-R01 Rev No.: 000

References:

- Depreciation – Minor Fixed Assets
- Reused Transformers Process
- Returns, Refurbishment's, System Reserve Assets and Strategic Spare Parts

Retirement/Surplus Form, Capitalization Procedure
http://operations.hydroonenetworks.com/web/root/bi-bpi_assets.htm

Investment Recovery
http://gridweb.hydroone.com/ecs/sms/investment_recovery.html

Reused Transformer Process
http://operations.hydroonenetworks.com/web/sub/BusProcInfo/Assets/Reused_Transformers_Process.pdf

Surplus Declaration Field Instruction
http://operations.hydroonenetworks.com/web/root/bi-bpi_main.htm

Hydro One OAR
http://finance.hydroone.com/OAR/default.htm

Local Sale of Surplus Goods
http://operations.hydroonenetworks.com/web/root/bi-bpi_main.htm

Hazardous Waste Management
http://gridweb.hydroone.com/ecs/sms/investment_recovery.html

Document Number: **SP 0155 R1**

Document Name: **Purchase of Low Value Non-ACL External Contractor Services & Materials (Local Purchase Contract)**

Issue Date: **March 2008**

When in printed form, this document is uncontrolled.
It is the user's responsibility to verify that this copy matches the document on the Hods website.

The requirements of this document are mandatory.

Purpose

The purpose of this document is to provide a streamlined process to HONI employees for the purchase of contractor services or for material purchases when the value of such services/purchases is under $15,000 and the Contractor is not on the Approved Contractors List (ACL)

Revision

Contract Administration and Contract Monitor training courses will be updated according to this revision. This revision supersedes all previous contracting documentation (SP 0155 R0 and previous documentation posted on the SMS website relating to general services and construction services). The following major revisions have been made to the previous process:

- The document name has been changed from Local Contractor and Material Purchase Process (under $15,000 value) to Purchase of Low Value Non-ACL External Contractor Services & Materials (Local Purchase Contract) to better reflect the content of the document.
- Definitions have been aligned with those in HODS SP 0312. HODS SP0312 is utilized for the Purchase of External Contractor Services (Non local Purchase Order) including all purchases made with ACL vendors regardless of the value.
- References to Security Check now read Personnel Risk Assessment (PRA). The use of the term PRA is related to our obligations under NERC standards for the

North American electricity industry. Our compliance to NERC standards is mandatory, thus the language change.

- Further guidance is provided on the requisitioner's accountability for evaluating the contractor's qualifications in the area of health, safety and environment
- Clarification is provided on the application of the document. HODS SP 0155 only applies to purchases where the total value is under $15k and where the vendor is not on Hydro One's ACL (Approved Contractors List) and where the commitment is made directly by the Requisitioner without Purchasing Individual involvement (Local Purchase).
- Non-ACL vendors are to be utilized only in instances where an ACL vendor is not available or able to perform the work. In such cases, where the value of the services are less than $15k, and where Local Purchase Authority is being exercised in accordance with the OAR, the services are to be procured in accordance with HODS SP 0155. Responsibility for ensuring the contractor meets our Health, Safety, and Environment (HS&E) and Insurance requirements rests with the Requisitioner.
- Non-ACL requirements $15k or over are to be procured utilizing an M/R and the award must be handled by a Purchasing Individual in accordance with the OAR and HODS SP 0312 - Purchase of External Contractor Services (non Local Purchase Order). In these instances, responsibility for ensuring the contractor meets our HS&E and Insurance requirements rests with the Purchasing Individual.
- Purchases made with ACL vendors are not considered Local Purchases as Purchasing Individuals were involved upfront in the vendors being approved in the areas of HS&E and Insurance. HODS SP 0312 not SP 0155 applies to these purchases regardless of who makes the actual commitment to the vendor (Requisitioner or Purchasing Individual).
- Links are provided to the latest version of forms required in the execution of the process and the related policies and procedures.
- Emphasis is on the requirement to use the Local Purchase Contract form when the requisitioner places business directly with a non-ACL vendor.
- Clarification of the requirement by Hydro One for contractors deemed "Independent" by WSIB to obtain WSIB coverage even though WSIB deems the purchase of this coverage to be "optional" for independent contractors.

It is expected that the use of HODS SP 0155 will be minimal as the majority of external contractor services will be procured using the ACL and will align with the requirements of HODS SP0312.

Contents

1.0 Introduction

Two different processes, each defined by dollar value and who within HONI is responsible to ensure the contractor meets the HS&E and Insurance requirements, govern the purchase of services from a contractor or, in the case of local purchasing, materials:

- HODS SP 0312 - Contracted services (General and Construction) including Approved Contractors List (ACL) vendors and those non ACL vendor requirements $15,000 or over. Responsibility for ensuring contractor meets our HS&E and Insurance requirements rests with the SMS or SCM Purchasing Individual.
- HODS SP 0155 (this document) - Contracted services and materials with Non ACL vendors under $15,000 (Local Purchase Contract) - see Exceptions 4.1.2 this document. Responsibility for ensuring contractor meets our HS&E and Insurance requirements rests with the Requisitioner.

In either of these processes, the following principles apply:

- Rule 338 of the Hydro One Safety Rule Book will be followed.
- Contractors are responsible for the health and safety of their own employees and environmental impacts caused by their actions. Contractors must work to the same safety standards as Hydro One Employees.
- Contracts will be managed to ensure that health, safety and environmental responsibilities of Hydro One Networks Inc. and its contractors are clearly defined.

2.0 Definitions

- **Contractor:** A business or individual that is retained to supply equipment, materials or general construction or maintenance services and is not deemed an employee of Hydro One.
- **Contract Administrator**: The individual who has the responsibility to manage contracts for his/her work unit. This includes evaluation of a *Contractor's* safety & environment performance along with their compliance with the terms of a contract. For complex construction projects with multiple contractors a single individual may be assigned the responsibility of administering all contracts associated with a Construction Project. This includes making sure contractors adhere to schedules and contract terms & conditions. They are also responsible to evaluate safety and environment performance. These individuals are the single point of contact between Hydro One and the contractor(s)
- **Contract Monitor**: The individual chosen by the *Contract Administrator* to monitor the *Contractor's* compliance with the terms of the contract. These individuals are the Hydro One site contact.

- **Hydro One Rep:** The Contract Administrator or Contract Monitor assigned to perform the duties
- **Materials:** Any products purchased locally that are required to complete the work task.
- **Purchasing Individual:** This could be either a Commodity Team Leader or Buyer from Inergi Supply Management Services or personnel from Hydro One Supply Chain Services in Finance
- **Requisitioner:** Individual who requires a service to be delivered by an external *Contractor.*

3.0 Diligent Contracting

Whenever possible, the Approved Contractors List (ACL) is to be used for the selection of contractors. These vendors have already been vetted and as such do meet the requirements of Hydro One.

HONI employees are to follow SP 0312 when selecting and utilizing ACL vendors and/or any non-ACL vendors where the value of the requirement is estimated at $15,000 or greater. This process document, SP 0155, shall be followed when selecting and utilizing non-ACL vendors where the value of the requirement is estimated at less that $15,000.

When the services of a contractor are arranged locally and it is not possible to utilize a Contractor from the ACL due to the ACL vendor(s) being unavailable or unable to perform the work, there is also a need to ensure that a due diligence standard is applied. Due diligence means to "take every precaution reasonable in the circumstances to avoid harm" (health & safety or environment). Due diligence is not just a defense but it is also a general duty. As a duty, due diligence is a broad, flexible proactive obligation that goes far beyond "mere regulatory compliance". The degree of risk and the degree of control determine to a large extent what the specific actions of a person will be to ensure due diligence.

When hiring a contractor not already established on the ACL, it is important to take some basic actions for the protection of Hydro One Networks Inc. and its employees:

- The award process must include evaluation of safety performance and the provision of protection against hazards in Hydro One controlled workplace.
- Legal obligations under the contract are emphasized prior to the commencement of work
- All known safety risks and environmental concerns are clearly identified and communicated to the contractor.
- Performance of the contractor is monitored and documented in a systematic manner. Evaluations of poorly performing contractors will be forwarded to the Manager, Supply Chain Services, for recording and future consideration in selecting vendors.

The Hydro One Networks Local Purchase Contract form helps to ensure due diligence is being applied. Local Purchases of Contractor Services are to be made in accordance with the OAR, and may not exceed $15,000 in value.

4.0 Purchasing Contractor Services

4.1 Purchase of Local Contractor Services Using Hydro One Networks Inc. Purchase Order Form

4.1.1 When To Use the Local Purchase Contract form

Hydro One Networks "Local Purchase Contract" form must be used whenever the services of a local contractor are required. This form represents the contract between Hydro One Networks Inc. and the contractor.

The Local Purchase Contract form can only be used in the following situations:

- The value of the transaction is within local purchasing authority limits as established by each line of business. Purchase of services and materials with this form must follow the established criteria for purchases permitted using the Corporate Charge Card.

4.1.2 When Not to use the Local Purchase Contrcat form (Exceptions)

- The value of the transaction exceeds local purchasing authority limits as established by each line of business.
- The vendor is an ACL vendor (terms and conditions are pre-established under Blanket Purchase Order).
- The requirement is for rock drilling, blasting, caissons, major excavations, or for services which require ESPSCA/ CUSW labour requirements, performance bond or where a quality program, or regulatory or safety requirement is specified. In such instances, SP 0312 is to be followed and Purchasing Individuals are to be involved with the purchase and will establish the Purchase Order including appropriate terms and conditions.
- Hiring of Consultants. Direction for hiring Consultants comes from two documents: Corporate Policy on Consultants and Corporate Procedure for Retention of Consultants. (see Appendix A for links to these documents).

4.1.3 Where to Obtain Forms

Local Purchase Contract forms are available from:

http://finance.hydroone.com/Supply_Chain_Services/Forms_Cabinet/default.htm

5.0 Documents Required from Contractors/Role of Contract Administrators and Contract Monitors

Prior to the selection of the contractor and commencement of work, the following must be received by the requisitioner:

- **Certificate of Liability Insurance** confirming a minimum amount of $2 million and that the policy will not be changed or cancelled during its term.
- **WSIB Clearance Certificate** dated within 60 days confirming that the contractor is in good standing with the Workplace Safety & Insurance Board.

For all labour related contracts, forward contractor information (Name, address, phone number), and WSIB clearance certificate (certificate number) S Wabb (internal mail: TCT09 or fax: 416-345-6270). Note all contractors deemed by WSIB to be Independent Contractors are required by Hydro One to obtain WSIB coverage. This is optional as far as WSIB is concerned. However, it is a requirement of Hydro One's. To have this requirement waived requires V.P. approval.
For dependent Operators/Workers (those who do not have WSIB coverage), submit all

contractor hours monthly to S Wabb (internal mail: TCT09 or fax: 416-345-6270), to ensure Hydro One submits WSIB premiums on behalf of these operators/workers).

- **Equipment Safety Certificate**(s) relating to the worthiness of the equipment being provided as part of the contract. Refer to the Equipment Safety Certificate form on the SCM Website

http://finance.hydroone.com/Supply_Chain_Services/Forms_Cabinet/default.htm

- **Safety Performance*** confirming a satisfactory record of safety performance
- **Company Safety Policy**: A copy of their Health & Safety Policy signed and dated with the current year
- **Safety Management System: a Health and Safety program document or individual written procedures that reflect the company's knowledge of OHSA requirements and training records**
- **Labour Union compliance (BTU)**: provision of proof of faxed copy of the help req. to Workforce Acquisition
- **Personnel Risk Assessment Form (as required for unescorted access)**

Refer to SP 0312 for a more detailed description of how to assess the information received from the Contractor. The Contractor must not be permitted to begin work, if any of the above certificates are not provided. Where a *Contractor* does not meet all the above requirements but there is still a need or desire to hire the *Contractor* (i.e. is "only *Contractor* available"), approval to hire can be given by a Line of Business Vice President. In this case, additional controls may be necessary to ensure the *Contractor* delivers the service in an acceptable manner.

Note: HONI Health Safety and Environment are responsible for providing subject matter experts for health, safety or environment contracting issues, maintaining and delivering Contract Administrator and Contract Monitoring training. Each LOB shall ensure its Contract Administrators and Contract Monitors obtain the appropriate training. The role of the Contract Administrators and Contract Monitors is more clearly defined in HODS SP 0312 and within the training provided.

***Safety Performance: To verify contractor's safety performance obtain from contractor one of the following:**

Account Rate Profile

Workplace Injury Summary Report

Cost and Frequency Report

If report indicates Zero fatalities plus Zero Lost Time Injuries over the past 3 years, the contractor shall be deemed to have a satisfactory record of Safety Performance.

Or WSIB ratings in MAP, NEER or CAD which meet the requirements specified in HODS SP0312.

6.0 Contractor Orientation

In all cases, the contractor must be oriented to the work site (i.e., explanation of work to be carried out and hazards at the site). There are two orientation processes that must be used:

If Contractor is…	*Take these actions…*
Working with Networks Crew	• HYDRO ONE REP signs contractor employees onto the job plan as a member(s) of the crew • Hydro One Rep receives completed Equipment Safety Certification Form (see Appendix A) including operator certification (when applicable). • All contractor employees participate in all tailboard discussions • HYDRO ONE REP supervises the contractor • HYDRO ONE REP evaluates contractor performance using the Post-Contract Contractor Evaluation Form (see Appendix A for link), and forward the evaluation to as instructed on the form.
A Licensable skill/trade such as Plumber, Electrician or Crane Operator (applies whether workings with Networks Crew or independently)	• Hydro One Rep verifies qualifications and licence held by requirement for skilled trades (e.g. Plumber Certificate of Qualification (C of Q); Industrial Electrician C of Q; Crane Operator C of Q etc)
Working independently (not with an Networks crew)	CONTRACT ADMINISTRATOR: • meets contractor (on site if necessary) • completes "Contractor Safety & Environment Pre-Job Meeting Checklist" (see Appendix A for link to form) and ensures that all known hazards are explained to the contractor. • highlights obligation of contractor to report all accidents, incidents and regulatory Orders to Comply immediately to Hydro One • signs and has the contractor sign the Checklist • receives completed Equipment Safety Certification Form (see Appendix A) including operator certification (where applicable) • attaches completed Checklist to Purchase Order form • monitors the contractor's work as arranged

	• evaluates contractor performance using the Post-Contract Contractor Evaluation Form (see Appendix A for link), and forward form as instructed on the form.

Appendix A: Associated Documents:

- Code of Business Conduct available at http://law.hydroone.com/Executive%20Services_Root/Code%20of%20Business%20Conduct.htm

- Executive and Organizational Authority Registers (EAR/OAR) available at http://finance.hydroone.com/

- Local Purchasing Procedure available at http://finance.hydroone.com/Supply_Chain_Services/Policies_and_Procedures/default.htm

- HODS SP 0312- Purchase of External Contractor Services (Non local Purchase Order)# at http://discovery.hydroone.com/hods/Info/Documents/SP0312.htm

- Corporate Policy on Consultants at http://finance.hydroone.com/Supply_Chain_Services/Policies_and_Procedures/default.htm

- Corporate Procedure for Retention of Consultants at http://finance.hydroone.com/Supply_Chain_Services/Policies_and_Procedures/default.htm

- Work Methods & Training Website at http://gridweb.hydroone.com/hse/

- Approved Contractors List(ACL) at http://finance.hydroone.com/Supply_Chain_Services/Approved_Contractors_List/default.htm

The following are available at http://finance.hydroone.com/Supply_Chain_Services/Forms_Cabinet/default.htm

- Local Purchase Contract form and instructions
- Equipment Safety Certificate form
- Personnel Risk Assessment Form
- WSIB Contractor Questionnaire
- Contractor Safety & Environment Pre-Job Meeting Checklist
- Incident Reporting for Work Done under Contract to Ontario Power Generation (OPG)
- Post-Contract Contractor Performance Evaluation form

Energy Probe INTERROGATORY #2 List 1

Interrogatory

Ref: Exhibit A, Tab 15, Schedule 1, pages 9 – 10

The tables on these pages compare Hydro One reliability performance to the CEA "composite". Please explain:

a) How many other transmission utilities are included in the composite?

b) How many other transmission utilities do not participate in the CEA study?

c) How are the composite performance numbers calculated?

Response

a) Nine other transmission utilities participated in the CEA study. Their data are included in the composite values in the charts on pages 9-10 in the referenced exhibit.

b) Seven other transmission utilities do not participate in the CEA study relating to the results in the referenced exhibit.

c) The composite performance numbers for each measure are calculated by dividing the sum of all delivery point interruptions reported to the study, by the sum of all delivery points in the population of the study.

Energy Probe INTERROGATORY #3 List 1

Interrogatory

Ref: Exhibit A, Tab 15, Schedule 1, page 13

Table 3 compares reliability data for Hydro One and US Transmission utilities. Hydro One performance in the 100-161 kV class is mostly in the third and fourth quartiles.

a) Please provide an analysis of the reasons for outages on the 115 kV system.

b) Why is the SAIFI for sustained outages worse than for momentary outages?

c) In the DP Outages per 100 mi. Hydro One is in the second quartile. What causes the SAIFI numbers then to be in the 3rd and 4th quartiles?

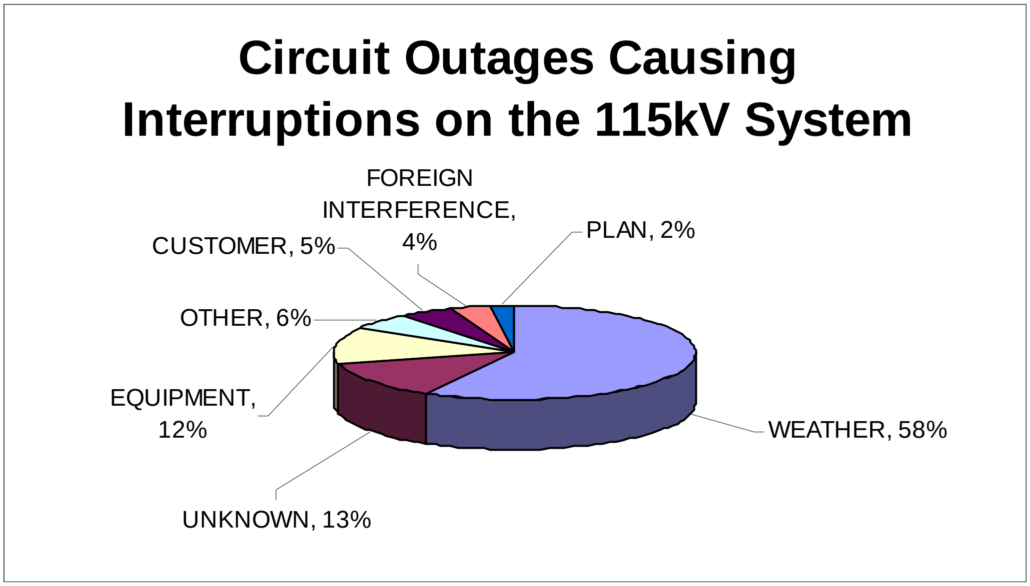
d) What factors cause T-SAIDI to be in the 4th quartile?

e) How much of the 230 kV system is also radial and rural? How does reliability performance for that part of the 230 kV system compare to the 115 kV system?

f) What actions can Hydro One take to improve reliability of its 115 kV system?

Response

a) Table 3 in the referenced exhibit is based on circuit (transmission line) reliability performance. Results of an analysis on outage causes affecting the supply from the Hydro One 115kV transmission system are illustrated in the chart below. The chart illustrates that the dominant cause of circuit outages causing load interruptions is due to weather conditions. Hydro One's transmission system covers a very large service area and contains very long circuits, relative to other transmission systems. Long circuits are more exposed to weather conditions than shorter circuits in smaller service areas.



Results over the 2003-2007 period. Includes momentary and sustained events.

b) The information provided in Table 3 of the reference are not absolute values, they are relative comparisons within the context of each measure. The results do not indicate that T-SAIFI for sustained outages is worse than for momentary outages. The results in Table 3 of the reference indicate that Hydro One's sustained outage performance compared to sustained outage performance of the other transmission utilities that participated in the study. Similarly, the results of Hydro One's momentary outage performance is provided relative to momentary outage performance of the other transmission utilities. These two measures are tracked and compared separately. Therefore, one cannot compare one relative comparison result to another comparison result.

c) Hydro One's 100-161kV DP Outages per 100mi result is 2nd quartile in the comparison and the T-SAIFI results are in the 3rd and 4th quartiles. This indicates that when accounting for (normalizing by) circuit length, Hydro One's performance is 2nd quartile compared to the population of transmission utilities participating in the study. As discussed earlier in part b), the Hydro One transmission system has very long circuits which are more exposed to weather conditions than shorter circuits in smaller service areas. Normalization by circuit length provides a more level playing field for comparing performance among transmission systems involving varying circuit lengths.

d) T-SAIDI in the 100-161kV range is 4th quartile compared to the population of transmission utilities participating in the study. In addition to the statements in the response to part a) of this question (above), it takes time to locate sustained faults on long, remote circuits. And, when located, it may be difficult to access thereby increasing repair time, even in ideal conditions. Performance is somewhat better when normalizing by circuit length (DP Minutes per 100mi).

e) Only 2% of 230kV the system is radial while 30% of 115kV system is radial. The figures in Table 3 pertain to circuit outage performance. Performance of the radial 230kV system has historically performed better than the radial 115kV system. The design of 230kV circuits, due to the higher voltage, requires higher insulation levels and greater clearances between conductors and the supporting structure and underbuilds. These standard design criteria help to make the circuit less susceptible to conditions causing faults.

f) Hydro One takes a number of actions to improve reliability where it is cost effective to do so. This is in addition to the capital replacement programs defined in Exhibit D1, Tab 3, Schedule 2.

Improvement initiatives include:

- Installation of lightning arrestors on circuits that are experiencing a high number of lightning outages on a regular basis.
- In locations where conductors are prone to galloping, Hydro One has installed anti-galloping devices to prevent conductors from clashing.
- Adding redundancy by constructing a second supply.
- Installation of switches to facilitate sectionalizing thereby reducing the time to restore power to customers.
- Installation of electronic fault locating equipment to assist in identifying the fault location.

Energy Probe INTERROGATORY #4 List 1

Interrogatory

Ref: Exhibit A, Tab 16, Schedule 2, Attachment 1

This attachment is a compensation and productivity comparison study of Hydro One by Mercer and Wyman. Page 12 discloses that the compensation survey reflects only 47% of Hydro One employees.

a) What was the breakdown of the other 53% of employees not included in the study by employee grouping as used in the study?

b) Was any analysis (statistical or otherwise) performed to determine how the other 53% of employees not represented in the study would have affected the results had they been included?

Response

The Compensation Cost Benchmarking Study was prepared by Mercer / Oliver Wyman.

a) See the attached.for a listing of the approximately 700 Hydro One positions which were not included in the benchmarking study.

b) No. Please refer to section 3 of the letter by Mercer provided as the Attachment to Exhibit I, Tab 7, Schedule 6.

Job Code	Job Title	Representation
672558	Protection And Control Enginee	SOCIETY
710021	Project Manager	SOCIETY
672553	Protection And Control Supvr	SOCIETY
410487	FLM - Lines	SOCIETY
786001	Eng/Off-Transmission Opg Tools	SOCIETY
739096	PROGRAMS ANALYST	SOCIETY
786002	Team Leader/Senior Advisor	SOCIETY
670551	Technical Supervisor	SOCIETY
711097	Senior Technical Specialist	SOCIETY
650060	Planner	SOCIETY
739812	Load Forecast Mgmt Analyst	SOCIETY
650318	Senior Design Specialist - Stn	SOCIETY
672211	Shift Control Engineer/Officer	SOCIETY
710308	Senior Telecommuncations Analy	SOCIETY
729094	Stations Services Specialist	SOCIETY
734093	Information Technology Analyst	SOCIETY
739819	Materiel/Resource Forecasting	SOCIETY
741421	Sr Real Estate Coordinator	SOCIETY
785504	Customer Support Supervisor	SOCIETY
640202	Safety/Envrnmnt Coordinator	SOCIETY
650025	Environment Planner/Engineer	SOCIETY
741895	Maintenance Scheduler	SOCIETY
759812	Account Executive	SOCIETY
759819	Training Specialist	SOCIETY
784400	Sr Eng/Off-Trans Oprtg Tools	SOCIETY
435482	Fleet Maintenance Supervisor	SOCIETY
650083	Design Eng Spec Line Struct	SOCIETY
650304	Senior Design Specialist	SOCIETY
652021	Design Engr Specialist - Stati	SOCIETY
654302	Senior Project Engineer	SOCIETY
656203	Service Provisioner Eng/Off	SOCIETY
662025	Equipment Engr - Specialist	SOCIETY
664003	Planning & Control Engineer/Of	SOCIETY
672302	Senior Protection And Control	SOCIETY
781007	Totalization Table Coordinator	SOCIETY
620316	Senior Materiel Management Eng	SOCIETY
656017	Telecom Project Engineer/Off	SOCIETY
730441	Senior Accounting And Financia	SOCIETY
730849	Planning And Control Srvcs Off	SOCIETY
739508	Distribution Eng/Officer	SOCIETY
739813	Billing & Meter Read Analyst	SOCIETY
753207	Ass't Eng/Off -Ops Tools & Fac	SOCIETY
755006	Facility Coordinator	SOCIETY
784804	Sr Lines Technical Officer	SOCIETY
630302	Senior Cae Application Eng/Off	SOCIETY
671015	Sr Remote Community Eng/Offcr	SOCIETY
672063	Maintenance Engineer	SOCIETY
690031	Network Mgmt Eng/Off	SOCIETY
709035	Business/Finance Grad	SOCIETY
709405	Senior Comptrollership Advisor	SOCIETY

Job Code	Job Title	Representation
729093	Master Schedule Resource Spec	SOCIETY
729811	Sr Bus Processes Specialist	SOCIETY
730840	Business Analyst	SOCIETY
730860	Sr Acct'g & Financial Analyst	SOCIETY
734090	Business Process Analyst	SOCIETY
734096	Business System Analyst	SOCIETY
734806	Service Management Analyst	SOCIETY
736009	Business Analyst	SOCIETY
741422	Sr Project Cood Products Dlvry	SOCIETY
754502	Team Leader - Field Services	SOCIETY
754520	Grid Operations Supervisor	SOCIETY
756039	Supt. Customer Contracts & Bus	SOCIETY
781015	Health & Safety Coordinator	SOCIETY
786003	Work Methods Specialist	SOCIETY
786009	FLM - Field Technical Services	SOCIETY
623015	Quality Assurance Manager	SOCIETY
650026	Design Engineer Specialist Dev	SOCIETY
650085	Dsgn Engr-Line Elec&Undergrnd	SOCIETY
650572	Sr Supvr - Resource Deployment	SOCIETY
651026	Design Engineer - Specialist	SOCIETY
654004	Dsgn Engr-Speclist-Structural	SOCIETY
656202	Customer Applications Engineer	SOCIETY
662041	Equipment Engineer	SOCIETY
662123	Assistant Estimating Engineer	SOCIETY
685002	Landscape Architect	SOCIETY
685003	Project Forester	SOCIETY
685011	Distribution/Transmn Forester	SOCIETY
701018	Accounting & Financial Analyst	SOCIETY
729412	Sr. IT Specialist	SOCIETY
729413	Senior Network Specialist	SOCIETY
729414	Sr Specialist - Environmental	SOCIETY
729815	Barrie Warehse Inventory Spec	SOCIETY
734091	Project Management Analyst	SOCIETY
734098	Financial Analyst	SOCIETY
741423	Sr Products Coordinator	SOCIETY
743800	Project Manager	SOCIETY
747569	Meter & Relay Services -FLM	SOCIETY
748460	Sr. Customer Business Officer	SOCIETY
748894	Contract Admin/Field SC Coord	SOCIETY
748895	Advisor, Pricing & Rates	SOCIETY
753880	Grid Operations Spprt Offcr	SOCIETY
753881	Community Relations Offcr	SOCIETY
753884	Advisor, Regulatory Affairs	SOCIETY
754519	Acquisition & Spec Prjcts Spvr	SOCIETY
756018	Account Exec - Utility Sales	SOCIETY
784803	Distribution Lines Eng/Officer	SOCIETY
784805	Ass't Distrib Lines Eng/Off	SOCIETY
786004	Customer Relations Team Leader	SOCIETY
786010	Advr, Customer Connectivity	SOCIETY
415396	FLM - Forestry	SOCIETY

Job Code	Job Title	Representation
415885	Warehouse Operations Supvr	SOCIETY
415888	FLM - Stations	SOCIETY
415889	FLM - Central Tool Services	SOCIETY
417084	FLM - Generation Mtce & Oprtns	SOCIETY
610306	Sr Contract Engr/Officer Admin	SOCIETY
620502	Senior Municipal Regulation An	SOCIETY
620504	Retail Service Officer	SOCIETY
650202	Asst Rsrce Dplymnt Est Eng/Off	SOCIETY
652026	Design Engineer Specialist - E	SOCIETY
652051	Teleprotection Engineer - Spec	SOCIETY
652603	Supt - Design, Constr & Asset	SOCIETY
654020	Project Engineer	SOCIETY
656033	Telecommunications Eng/Offr	SOCIETY
656504	Group Leader, Telecom	SOCIETY
662012	Estimating And Scheduling Engi	SOCIETY
670578	District Services Specialist	SOCIETY
671515	Regional Line Supervisor	SOCIETY
672062	Transmission Engineer/Officer	SOCIETY
672135	Assistant Engineer	SOCIETY
672573	Data Collection & Perform Supv	SOCIETY
690027	Contract Engineer/Officer	SOCIETY
690030	Fleet Engineer	SOCIETY
690510	Sr Supervisor - Work Mgmt	SOCIETY
700404	Auditor	SOCIETY
702511	Team Leader - Accounting & Rep	SOCIETY
710002	Technical Analyst	SOCIETY
710521	Mgr, Project Report & Analysis	SOCIETY
711312	Sr Architecture Specialist	SOCIETY
712300	Senior Operations Analyst	SOCIETY
727402	Sr. Mrkt Researcher & Coordtor	SOCIETY
729096	Grid Ops Inventory Specialist	SOCIETY
730436	Senior Financial Analyst	SOCIETY
730460	Senior Financial Coordinator	SOCIETY
730863	Integrated Planning Analyst	SOCIETY
734055	Customer Intelligence Spec	SOCIETY
734095	Work Program Systems Analyst	SOCIETY
734099	Business System Analyst	SOCIETY
734808	Financial and Business Analyst	SOCIETY
734810	Assistant Bus System Analyst	SOCIETY
739069	Corporate Relations Analyst	SOCIETY
739098	Performance Analyst	SOCIETY
739420	Sr Load Forecast Mgmt Analyst	SOCIETY
739808	Transmn Connections Analyst	SOCIETY
739811	Chief Scheduler/Analyst	SOCIETY
739818	Applications Analyst	SOCIETY
739822	Real Estate & Fac Bus Analyst	SOCIETY
741210	Assistant HSE Coordinator	SOCIETY
741211	Ass't Hlth & Safety Coord	SOCIETY
741424	Sr Program Coordinator	SOCIETY
741512	Client Services Coordinator	SOCIETY

Job Code	Job Title	Representation
743531	Carrier Services Manager	SOCIETY
743838	Service Manager - HO Telecom	SOCIETY
743841	Manager, Outside Plant Mgmt	SOCIETY
743843	Work Program Manager	SOCIETY
747419	Sr Advr Custmr Products Dlvry	SOCIETY
747592	Admin Supvr/Fleet Analyst	SOCIETY
747843	Lines Coordinator	SOCIETY
747851	Business Support Supervisor	SOCIETY
747852	Team Leader - Settlements	SOCIETY
748504	Communications & Community Rel	SOCIETY
748824	Trg Officer - Protection and C	SOCIETY
748854	Communication Development Coor	SOCIETY
748867	Business Systems &Training Off	SOCIETY
748892	Construction Services Officer	SOCIETY
748896	Advr, Load Forecast Management	SOCIETY
752406	Sr. Provincial System Forester	SOCIETY
753882	Network Mgmt Eng/Off	SOCIETY
753885	Sr Media Relations Officer	SOCIETY
753886	Joint Use Programs Eng/Off	SOCIETY
754503	Senior Integration Advisor	SOCIETY
754516	Sr Media & Pub Affairs Advisor	SOCIETY
755003	Customer/Regulatory Dev Coord	SOCIETY
755007	Corporate Charge Card Coord	SOCIETY
755404	Sr CDM Strategic Planner	SOCIETY
757822	Team Ldr - Environmental Srvcs	SOCIETY
757823	Supvr Environmental Operations	SOCIETY
759430	Senior Coord-Program Delivery	SOCIETY
765003	Training Instructor	SOCIETY
781001	On Line Communications Coodr	SOCIETY
781002	Lines Coordinator	SOCIETY
781003	Communications Prgm Coord	SOCIETY
781010	Coordinator, Vendor Mgmt	SOCIETY
781012	Coordinator	SOCIETY
781020	EHS Program Mgmt Coordinator	SOCIETY
784401	Sr Eng/Offr-Trans Op Tools Imp	SOCIETY
784402	Sr Technical Srvcs Eng/Off	SOCIETY
784801	Project Control Eng/Officer	SOCIETY
785501	Supvr - Records Management	SOCIETY
785503	Supv - Helicopter Mtce	SOCIETY
786005	IM/IT PCO Administrator	SOCIETY
786007	Reporting & Financial Advisor	SOCIETY
786011	Advr - Program Integration	SOCIETY
786012	Regulatory Coordinator	SOCIETY
840703	General Foreman "B" - Lines/St	SOCIETY
864605	Construction Field Eng/Off	SOCIETY
410312	Lines Apprentice (4 Year Prog)	PWU
415316	Elec Forester Labourer Journey	PWU
415311	Elec Forester Apprentice (4Yr)	PWU
410321	Regional Maintainer-Lines Impr	PWU

Job Code	Job Title	Representation
118007	University Co-Op Student	PWU
340039	Area Forestry Technician	PWU
411132	Regional Maintainer II - Elect	PWU
172007	Field Scheduling Oprtn's Clerk	PWU
313007	CAD Operator Elect & Telecom	PWU
415318	Elec Forester Labourer Forepsn	PWU
363041	Planning Scheduling Tech'n	PWU
411122	Regional Mntr-Elect Improver	PWU
172009	Lines Customer Support Clerk	PWU
210004	Grid Ops Controller Trainee	PWU
210005	Grid Ops Dispatcher Trainee	PWU
415313	Elec Forester Skid Oper Journ	PWU
322523	Sprv Distribution Technician	PWU
411031	Electrical Journeyperson	PWU
118006	University Student	PWU
343056	Distribution Line Technician	PWU
173019	Customer Oprns Support Rep	PWU
435341	Regional Mntnr I - Mechanical	PWU
313002	CAD Draftsperson Elec & Tele	PWU
313008	CAD Operator Layout/Elect	PWU
342023	Meter Technician - Cus Srv	PWU
381404	Supv Protection & Cntrl Tech	PWU
461231	Station Mtce & Inspection	PWU
118001	College Co-Op Student	PWU
322522	Sprv Distribution Technician	PWU
440060	Transport & Work Equip Mec UTS	PWU
313006	CAD Operator Mech/Civil/Struct	PWU
340032	Environment & Hlth Technician	PWU
340935	Maintenance Technician Trainee	PWU
435741	Regional Maintainer I - Civil	PWU
128618	Engineering Admin Support	PWU
342024	Meter Technician - Cus Srv	PWU
461161	Supervising Meter Reader	PWU
416330	Regional Site Mntce Person	PWU
101022	Project Accounting Specialist	PWU
000615	Records Clerk	PWU
313600	Sr CADD Designer - Elec & Tele	PWU
380059	Telecom Microwave Technologist	PWU
381928	Prot and Control Tech Trainee	PWU
410640	Regional Mntnr I-Cable Splicer	PWU
411143	Reg Maint - Power Equip Elec	PWU
435312	MechanTrade Apprentice (5 Yr)	PWU
001083	Drawing Records Clerk	PWU
112516	T/L Customer Srv Admin Centre	PWU
343072	Transmission Lines Eng Techn	PWU
363306	Senior Planning Technician	PWU
364034	Estimating, Sched & Cost Techn	PWU
415400	Helicopter Pilot	PWU
121087	Meter Data Agent	PWU
141311	Sr Scheduling Clerk	PWU

Job Code	Job Title	Representation
173020	Customer Consultant	PWU
300010	Grid Operations Technician	PWU
334037	Instructor - Lines	PWU
363042	Zone Distribution Plan Tech	PWU
415352	Regional Mntnr-Forestry UTS 3	PWU
415500	Air Engineer	PWU
122624	Maintenance Support Rep	PWU
210002	Dispatcher	PWU
343065	Transmission Lines Technician	PWU
363039	Scheduling Technician	PWU
411133	Asst Pwr Mtce Electrician - I	PWU
411223	Reg Mtnr - Pwr Equp Elec Impvr	PWU
427501	Waste Coordinator	PWU
427560	Stockkeeper Uts Level 2	PWU
435332	Mechanical Journeyperson	PWU
435761	Regional Mntnr-Civil UTS 2	PWU
050606	Administrative Assistant	PWU
110694	Business Support Co-Ordinator	PWU
112055	Team Ld - Field Admin Support	PWU
136618	Buyer	PWU
300009	Land Use Agent	PWU
310069	Gis Technician Iii	PWU
313601	Senior CADD Designer - Mech	PWU
313602	CAD Draftsperson Lay/Elec	PWU
313907	CAD Oper Elect & Tele Trainee	PWU
334035	Instructor - Forestry	PWU
343071	Work Methods Tech D/T Lines	PWU
345083	Meter & Relay Services Tech'n	PWU
435313	Mech Trades Apprentice (4 Yr)	PWU
435361	Regional Maintainer-Mech UTS 2	PWU
435530	Asst Mechanic Journeyperson	PWU
435733	Civil Journeyperson	PWU
455100	Truck Driver Class 1	PWU
112054	Workforce Acquisition Coord	PWU
114068	Support Services Clerk	PWU
180007	Regulatory Clerk	PWU
332521	Sprv Planning Technician	PWU
333019	Field Coordindator - TW&E	PWU
333028	Fleet Specialist	PWU
338002	Training Systems Technician	PWU
370412	Ass't Construction Technician	PWU
386001	Planning Technologist III	PWU
411067	Pwr Equip Elect Apprentice	PWU
415363	Elect Forester Sr Foreperson	PWU
427700	Handyperson	PWU
461120	Meter Reader Improver	PWU
001085	Junior Records Clerk	PWU
109663	Accounting Services Clerk	PWU
110599	Administrative Supervisor	PWU
127083	Real Estate Assistant	PWU

Job Code	Job Title	Representation
141670	TWE Clerk	PWU
179006	Grid Operations Clerk	PWU
182100	Administrative Assistant	PWU
334036	Instructor - Stations	PWU
343507	Suprv Forestry Technician	PWU
363040	Zone Planning Technician	PWU
364108	Asst Estim, Sched & Cost Techn	PWU
370319	Sr Construction Technician	PWU
386002	Customer Connectivity Tech	PWU
390098	Computer Applications Tech	PWU
411051	Electrical Subforeperson	PWU
415317	Elec Forester Labourer SubFore	PWU
427561	Waste Coordinator - Uts Lvl 2	PWU
435321	Regional Mntner-Mech Improver	PWU
435432	Mechanic "B"	PWU
000616	Materiels Records Clerk	PWU
084605	Document Processor	PWU
102602	Customer/Vendor Administr	PWU
112058	AMI Team Lead	PWU
121116	Computer Technical Assistant	PWU
127084	Real Estate Clerk	PWU
131016	Meter Control & Scheduling Clk	PWU
140064	Safety And Environment Clerk	PWU
150099	Artist	PWU
153046	Maintenance Support Clerk	PWU
170034	Engineering Support Ass't	PWU
313005	GIS Technician Ii - Telecom	PWU
330050	Waste Services Technician	PWU
333513	Supv Meter & Relay Srvcs Techn	PWU
338005	Grid Ops System Support Tech	PWU
342014	Insulation Test Technician	PWU
342503	Supv - Meter Support Techn	PWU
343069	Remote Com Dist Eng Meter Spec	PWU
344008	Work Methods Tech Stations	PWU
370308	Sr Construction Technician - S	PWU
385033	Systems Support Technologist	PWU
390523	Supervising E&H Technician	PWU
406030	Pwr Equipt Comp Refinisher-JP	PWU
410661	Reg Mntnr-Cable Splicer UTS 2	PWU
411152	Reg Maintainer-Electricl Uts 3	PWU
411231	Power Equip Electrician B JP	PWU
415332	Regional Mntnr II - Forestry	PWU
416360	Regional Site Mntce UTS	PWU
020529	Data Clerk-Typist	PWU
020625	Clerk-Typist	PWU
060035	Grid Operations Receptionist	PWU
100091	Cost Accounting Clerk	PWU
102095	Fleet Services Payables Clerk	PWU
102601	Rental Tool Srvces Coordinator	PWU
105043	Treasury Clerk	PWU

Job Code	Job Title	Representation
105527	Specialized Services Team Ldr	PWU
109128	Customer Accounts Rep	PWU
109401	Publications Media Assistant	PWU
109549	Customer Care Team - Lead	PWU
109661	Acct Clerk, Remote Communities	PWU
110651	Accommodation Planning Clerk	PWU
110687	Real Estate Administrative Cle	PWU
112052	Team Lead Admin Forestry Srvcs	PWU
112057	Acquisition Support Coord	PWU
120038	Estimating Clerk	PWU
121987	Meter Data Agent	PWU
122626	Technical Clerk	PWU
122627	Fleet Scheduling Clerk	PWU
124080	Fleet Operations Clerk	PWU
124085	Helicopter Servcs Coordinator	PWU
127086	Employee Relocation Counsellor	PWU
128061	Project Data Clerk II	PWU
136619	Contract Management Buyer	PWU
139049	Construction Tool Clerk	PWU
140394	Sr Clrk Facilities & Sprt Svcs	PWU
140663	Communications Assistant	PWU
141677	Proposal/Contract Clerk	PWU
141678	Disability Mgmt Assistant	PWU
143504	Corporate Archives Assistant	PWU
149088	General Office Assistant	PWU
154044	Operations Support Clerk	PWU
154046	Regulatory Research Assistant	PWU
154051	Telecom Planner	PWU
154052	Field Office Clerk	PWU
154053	Distribution Information Clerk	PWU
154054	Telecommunications Srv Coord	PWU
154055	Special Services Support Clerk	PWU
154056	Senior Fleet Services Clerk	PWU
154059	Operating Support Clerk	PWU
172004	Field Clerk	PWU
172006	Admin Field Support Clerk	PWU
173021	Business Support Clerk	PWU
179005	Customer Notification Clerk	PWU
180009	HSE Communications Assistant	PWU
300000	Assistant Environment Speciali	PWU
313001	Cadd Technician	PWU
313003	CADD Designer - Mechanical	PWU
313906	CAD Oper Mech/Cvl/StrcTrainee	PWU
313908	CAD Oper Layout/Elect Trainee	PWU
332074	Titles Technician II	PWU
334017	Resource Production Technician	PWU
334034	Instructor - Area Dis Eng	PWU
338001	Equipment Rating Technician	PWU
338006	Distribution Line Tech - Gen	PWU
340030	Distribution Technician (Fores	PWU

Job Code	Job Title	Representation
340036	Lines Technician	PWU
340038	Meter & Relay Quality Tech	PWU
340302	Sr Short Circuit Analysis Tech	PWU
342302	Senior Information Technology	PWU
343061	Transmission Lines Technician	PWU
370427	Construction Technician	PWU
381405	Planning Technologist I	PWU
383000	Architectural Technologist I	PWU
383004	Sr. Architectural Technologist	PWU
383005	Architectural Technologist II	PWU
385028	Systems Support Technologist	PWU
385029	Display Support Technologist	PWU
385032	Project Support Technologist	PWU
385034	GIS Systems Support Tech	PWU
385035	Coord Field Service Telecom	PWU
389301	Sr Protection Performance Tech	PWU
389400	Engineering Tech Telecom	PWU
390123	Operations Technologist	PWU
400030	Carpenter - Journeyperson	PWU
410131	Switching Agent	PWU
410400	Powerline Maintainer Special	PWU
411061	Electrical Sr Foreperson	PWU
411066	Pwr Equip Elect Journeyperson	PWU
411112	Regnl Mntner - Elect Learner	PWU
411153	Lines Subforeperson	PWU
415319	Elec Forester Labourer SrFore	PWU
415325	Elec Forester Skid Op SubFore	PWU
416230	Maintenance Person	PWU
435352	Mechanical Subforeperson	PWU
435363	Mechanical Foreperson	PWU
435431	Mechanic 'A' Electrician	PWU
441030	Accessories Installer JP	PWU
446630	Rigger Journeyperson	PWU
480430	Janitor 'A' Journeyperson	PWU
481830	Customer Service Rep JP	PWU
513695	Grid Operations Manager	MCP
502789	Grid Operations Field Mgr	MCP
513733	Forestry Manager	MCP
513662	Distribution Super Prov Lines	MCP
513708	Customer & Business Srvcs Mgr	MCP
592077	Human Resources Consultant	MCP
748830	Disability Mgmt Consultant	MCP
513235	Manager, Grid Operations	MCP
513704	Sustainment Manager	MCP
519057	Senior Legal Counsel	MCP
513574	Manager, Major Projects	MCP
513609	Area Superintendent	MCP
592098	Sr Health Safety & Env Advisor	MCP
592104	Team Ld Protect, Cntrl & Meter	MCP

Job Code	Job Title	Representation
592106	Sr Regulatory Advisor	MCP
502790	Grid Operations Planning Mgr	MCP
513502	Security Consultant	MCP
513550	IT Account Manager	MCP
592107	Sr. Fin Advr - Bus Controls	MCP
502786	Team Lead -Telecom Engn'g	MCP
592076	Human Resources Assistant	MCP
592105	Team Ld Stations Engineering	MCP
110316	Sr. Human Resources Assistant	MCP
513668	Manager, Telecom Operations	MCP
513688	Mgr, Conservation Demand Mgmt	MCP
513689	Mgr, Program Dev & Deployment	MCP
513700	Customer Program Manager	MCP
513703	Facility Manager	MCP
513709	Training Manager	MCP
513732	Forestry Superintendent	MCP
513748	Mgr, Business Planning	MCP
519058	Legal Counsel	MCP
543079	Director, Project Mgmt Dlvry	MCP
502778	Manager - Cadd Services	MCP
513050	Mgr, HSE Field Support	MCP
513269	Sr Financial Advisor	MCP
513515	Sr IT Security Specialist	MCP
513528	Manager, Taxation	MCP
513598	Mgr, Bus Plan & Spec Studies	MCP
513628	Manager, Field Admin Srvcs	MCP
513677	Manager, Business Management	MCP
513685	Mgr, Corporate Accounting	MCP
513705	Mgr, Fin Plann'g & Analysis	MCP
513710	Performance Manager	MCP
513711	Data Quality & Chge Cntrl Mgr	MCP
513714	Mgr, Financial Program Srvcs	MCP
513719	Support Network Manager	MCP
513725	Reliability Standards Manager	MCP
513726	Transmission Plan'g Mgr - West	MCP
513861	Control Centre Hardware Mgr	MCP
543082	Dir, Carrier Relat & Part Rel	MCP
592072	Occupational Health Nurse	MCP
592086	Executive Desktop Support	MCP
592092	Sr Fin Advr Int Fin Rpt & Cnt	MCP
592095	Sr Financial Advr - Corp Acct	MCP
592096	Sr Treasury Advisor	MCP
592110	Sr Regulatory Advisor	MCP
592114	Theft of Electricity Invest	MCP
711095	Sr Advisor - Decision Support	MCP
740508	Pension Administration Analyst	MCP
000000	Title Unavailable	MCP
050071	Administrative Assistant	MCP
110125	Labour Relations Assistant	MCP
180005	Comp Ben&Hlth Srvcs Specialist	MCP

Job Code	Job Title	Representation
502760	Manager Stations Engineering	MCP
502764	Mgr, Investment Intg & Stns	MCP
502768	Manager Lines Engineering	MCP
502769	Mgr Lines & Stns Engineering	MCP
502771	Superintendent, Western	MCP
502772	Mgr, Program & Wokrforce Mgmt	MCP
502775	Superintendent, Eastern Mtce	MCP
502781	Mgr, Project Control Systems	MCP
502791	Mgr, P&C Technical Services	MCP
502793	Mgr, Meter, Relay & Data Acq	MCP
502794	Mgr, MSP Services	MCP
502795	Mgr - 3D Standards Development	MCP
502796	Superintendent - GTA Stn Mtce	MCP
502798	Superintendent, Northern	MCP
502799	Superintendent, Central	MCP
512952	Manager, Decision Support	MCP
512987	Mgr - Distribution Pricing	MCP
513196	Mgr, Financial Mod & Analysis	MCP
513208	Manager Environment, H&S Audit	MCP
513264	Manager, Planning + Reporting	MCP
513379	Sr Advisor, Regulatory Review	MCP
513380	Manager, Treasury Operations	MCP
513383	Manager, Risk + Insurance	MCP
513402	Manager, Cost Accounting	MCP
513425	Manager, Public Affairs	MCP
513442	Group Mgr, P&C & Telcom Eng	MCP
513444	Mgr - Integrated System Spprt	MCP
513470	Mgr, Staffing & Leadership Dev	MCP
513475	Audit Associate	MCP
513487	Sr Advr/Program Mgr Community	MCP
513488	Labour Relations Manager	MCP
513498	Senior Advisor	MCP
513509	Mgr Environ Srvs & Approvals	MCP
513510	Sr Mgr, Income Tax Compliance	MCP
513517	Mgr, Revenue & Financial Srvcs	MCP
513523	Manager, Business Integration	MCP
513545	Mgr, Asset Strategies & Stand	MCP
513565	Manager, Finance & Integ	MCP
513568	Mgr, Performance Analysis	MCP
513576	Mgr, Stations & Telecom Prgrms	MCP
513579	Mgr, Distrib, Dev & Lines Sust	MCP
513580	Mgr, Generation Connections	MCP
513584	Manager, Business Integration	MCP
513586	Manager, Fleet Services	MCP
513592	Program Mgr, Cust Serv Initiat	MCP
513604	Senior Financial Auditor	MCP
513606	Mgr - Supply Chain Management	MCP
513616	Mgr, Change Management & Comm	MCP
513618	Mgr-Design & Technical Support	MCP
513621	Manager, Warehouse Operations	MCP

Job Code	Job Title	Representation
513624	Chief Estimator	MCP
513629	Mgr, Mass Market Management	MCP
513632	Manager Helicopter Operation	MCP
513634	Mgr, Mtce Technical Services	MCP
513637	Manager Customer Support	MCP
513639	Manager Information Assets	MCP
513642	Manager - Customer Care	MCP
513646	Senior Advisor	MCP
513648	IM/IT Services Manager	MCP
513650	Mgr - Economics & Load Fore	MCP
513651	Supt - Hamilton/Niag Mtce Svcs	MCP
513653	Mgr Emer Prep & LOB Risk Asses	MCP
513655	Mgr Quality Assur & Bus Supp	MCP
513656	Manager, Contracts	MCP
513659	Mgr, Compensation and Benefits	MCP
513660	Mgr, Transmission & Dstrb Sett	MCP
513663	Mgr, Investor Relations	MCP
513664	Manager, Transmission Planning	MCP
513665	Sr Information Techn Auditor	MCP
513669	Senior Auditor	MCP
513672	Distribution Development Mgr	MCP
513674	System Software Manager	MCP
513675	Mgr, Fin Reprtg & Acctg Policy	MCP
513676	Mgr, Project Mgmt & Control	MCP
513678	Service Support Manager	MCP
513679	Network Applications Manager	MCP
513680	NMS Data Services Manager	MCP
513682	Manager, Financial Services	MCP
513686	Mgr, Financial Plan & Analysis	MCP
513690	Manager - Work Management	MCP
513691	Manager - Technical Services	MCP
513692	Mgr, Distribution Planning	MCP
513693	Manager - HR Operations	MCP
513694	Mgr, Work Methods & Training	MCP
513696	Manager	MCP
513698	Manager, Financial Services	MCP
513699	Sr Manager - Outsourcing	MCP
513701	Mgr, Business & Strategy Pln'g	MCP
513702	Systems Support Manager	MCP
513706	Forestry Technician Manager	MCP
513712	Integrated Data Manager	MCP
513713	Integrated Process Manager	MCP
513715	Business Systems & Suprt Mgr	MCP
513716	Work Methods Manager	MCP
513717	Manager, P&C Programs	MCP
513718	Manager, Transmission Pricing	MCP
513720	Programs Support Manager	MCP
513721	Manager IT Security	MCP
513722	Commercial Agreements Mgr	MCP
513723	Standards Development Mgr	MCP

Job Code	Job Title	Representation
513724	Manager, Internal Control	MCP
513727	Interconnections Manager	MCP
513728	Mgr - HSE Eng'ng & Tech Suppt	MCP
513729	Manager - Customer Service	MCP
513730	Program Integration Manager	MCP
513731	Special Studies Manager	MCP
513734	Mgr, Financial & Acct'g Servcs	MCP
513735	Distribution Technician Mgr	MCP
513736	Mgr, Corporate Communications	MCP
513737	PMO Manager	MCP
513738	Sr Manager, Commodity Tax	MCP
513739	Manager - Business Support	MCP
513740	Mgr, Trans Load Connections	MCP
513741	Mgr - Workforce Acquisition	MCP
513743	Inventory Manager	MCP
513744	Mgr, Metering & Tech Services	MCP
513745	Manager, Regulatory Finance	MCP
513746	Mgr, Customer Cntrcts & Prgms	MCP
513747	Mgr, Telecom Project Mgmt	MCP
519047	Assistant General Counsel	MCP
519050	Assistant General Counsel	MCP
519088	Assistant General Counsel	MCP
519090	VP, Supply Chain Services	MCP
532693	Director, Provincial Lines	MCP
532694	Director of Engineering	MCP
532695	Director, Project Management	MCP
532697	Director - Construction Srvcs	MCP
543041	Director, Corporate Security	MCP
543048	Dir, Corporate Communications	MCP
543066	Dir, Finance, Admn, Regulatory	MCP
543067	Director, Performance Mgmt	MCP
543068	Senior Real Estate Manager	MCP
543069	Dir, Strategy & Conservation	MCP
543071	Director, Supply Connections	MCP
543073	Director, Development Strategy	MCP
543074	Proj Dir, Hydro One Networks	MCP
543075	Director, Pension Fund	MCP
543086	Corp Secretary & Corp Ethics	MCP
543087	Director - Human Resources	MCP
543088	Dir, Mergers & Acquisitions	MCP
543093	Director, Network Operating	MCP
543094	Director Network Strategy	MCP
543095	Director Transmission Rgltn	MCP
543096	Director, Remote Communities	MCP
543097	Director Marketing	MCP
543099	Director, Information Tech Sys	MCP
543102	Project Director	MCP
543103	Director, Applications	MCP
543104	Director - Station Maintenance	MCP
543105	Director, Grid Customer Srvcs	MCP

Job Code	Job Title	Representation
543106	Director Work Mgmt & Tech Svcs	MCP
543107	Customer Care Director	MCP
543109	Director, Forestry Services	MCP
543110	Director, IT Service Delivery	MCP
543111	Director, IT Operations	MCP
543114	Director, Work Program Optim	MCP
543115	Director, System Investment	MCP
543116	Director, Telecom Operations	MCP
543117	Director, Aboriginal Affairs	MCP
543118	Dir, Corporate Account & Reprt	MCP
543120	Dir, Business Integration	MCP
543123	Director, Real Estate	MCP
543125	Director, Asset Management	MCP
543126	Director, Treasury	MCP
543127	Dir, Fin & Operational Audit	MCP
543128	Dir, Information Systems Audit	MCP
592053	Administrative Assistant	MCP
592055	Distribution Super Prov Lines	MCP
592063	Asst Wrkfrc Acqstns Officer	MCP
592067	Supt Fleet Maintenance	MCP
592071	Labour Relations Consultant	MCP
592073	Advisor	MCP
592078	Compensation & Benefits Offcr	MCP
592084	Corporate Freedom of Info Off	MCP
592087	Assistant Staffing Consultant	MCP
592088	Rehabilitation Team Leader	MCP
592089	Paralegal	MCP
592090	Sr Financial Advr - Fin Sys	MCP
592091	Sr Financial Advr - Fin Plan	MCP
592093	Sr Fin Advr Ext Fin Rpt & Cnt	MCP
592094	Sr Financial Advr - Corp Func	MCP
592097	Sr Operations Treasury Advr	MCP
592100	Sr Advr, Bus Cont & Emerg Pln	MCP
592101	Sr Advisor - Pricing and Rates	MCP
592102	Sr Advr - Load Data Management	MCP
592103	Sr Advr - Load Forecast Mgmt	MCP
592108	Sr Labour Relations Consultant	MCP
592109	Assistant Law Clerk	MCP
592111	HSE Tech/Engineering Spec	MCP
592112	HR Controls Analyst	MCP
592113	Sr Financial Advr, Dec Suprt	MCP
700008	Auditor	MCP
740506	Team Leader, Rehab Srvs	MCP
743508	Customer Operations Manager	MCP
745515	Prgrm Mgr - Real Estate Mgmt	MCP
747701	Superintendent - Stn Services	MCP
753873	Human Resources Consultant	MCP
757408	Supt Operations & Maintenance	MCP
758813	Fleet Asset Mgmt Srvcs Manager	MCP
770003	M&P Trainee - Human Resources	MCP

Energy Probe INTERROGATORY #5 List 1

Interrogatory

Ref: Exhibit A, Tab 16, Schedule 2, Attachment 1

This attachment is a compensation and productivity comparison study of Hydro One by Mercer and Wyman. The survey results reveal on page 15 that Hydro One compensation on a weighted average basis is 17% higher than the median of survey participants. This is attributed to legacy collective agreement wages, pensions and benefits.

a) Legacy plans are reported as having been negotiated prior to Hydro One's formation in 1998. Since 10 years have now passed since its formation, does Hydro One have a plan to reduce or eliminate the effect of legacy collective agreement wage effects on its compensation levels?

b) Legacy pension benefits are noted as not available to new hires in the Management and Society groups. What is Hydro One's plan to treat PWU workers similarly for pension purposes?

c) Legacy benefit plans are noted as not available to new hires in the Management group. What is Hydro One's plan to treat PWU and Society workers similarly for benefit purposes?

Response

Correction: The Compensation Cost Benchmarking Study referred to in the question was prepared by Mercer / Oliver Wyman.

a) Hydro One has achieved a number of significant changes during collective bargaining to either reduce employee related costs or increase productivity. These changes are highlighted in Exhibit C1, Tab 3, Schedule 2, pp 7-9.

b) Hydro One has assessed the likelihood to achieve similar pension changes with the PWU and it has been determined that there is no reasonable chance to negotiate this without incurring a work stoppage. It is our further assessment that we do not believe a work stoppage is in the best interest of Hydro One or rate payers.

c) Hydro One has assessed the likelihood to achieve similar benefit changes with the PWU and the Society and it has been determined that there is no reasonable chance to negotiate this without incurring a work stoppage. It is our further assessment that we do not believe a work stoppage is in the best interest of Hydro One or rate payers.

Energy Probe INTERROGATORY #6 List 1

Interrogatory

Ref: Exhibit A, Tab 16, Schedule 2, Attachment 1

This attachment is a compensation and productivity comparison study of Hydro One by Mercer and Wyman. Table 5 on page 17 discloses comparative compensation data for non represented employees.

None of these positions appears to be in the executive management group of the company. Why was the executive group not included in the study?

Response

Correction: The Compensation Cost Benchmarking Study referred to in the question was prepared by Mercer / Oliver Wyman.

One of the guiding principles that the stakeholders agreed to was job comparisons should be at the job or class level and should focus on the fewest number of positions possible while representing the largest portion of employees possible. This principle strikes a balance between creating a survey that participants will complete and yielding results that crosses over a wide range of classifications. As such, it was determined that individual executive positions would not represent a significant portion of the employee population.

Further, with respect to executive compensation, in the EB-2006-0501 Decision, the Board directed Hydro One to track any reduction in Executive salaries during 2007 and 2008. Hydro One has accepted the recommendations of the Arnett Panel regarding executive compensation. The top 5 executive positions at Hydro One will have their compensation altered as the incumbents leave in order to follow the guidelines recommended by the Arnett Panel. To date, the positions of Chief Executive Officer and General Counsel have had their salaries reduced as discussed in Exhibit C1, Tab 3, Schedule 2, Page 16 to 17.

Energy Probe INTERROGATORY #7 List 1

Interrogatory

Ref: Exhibit A, Tab 16, Schedule 2, Attachment 1

This attachment is a compensation and productivity comparison study of Hydro One by Mercer and Wyman. Table 7 on page 19 discloses comparative compensation data for PWU represented employees in the study.

Although some argument might be made for over paying highly skilled positions, at least five of the positions in the table do not appear to fall into that category. Specifically, Service Dispatcher, Drafter II, Stock keeper, Data Entry Clerk, and Meter Reader positions would not seem to require extended apprenticeships or unusual skills. What is Hydro One's plan to bring compensation for these positions more in line with comparators?

Response

Correction: The Compensation Cost Benchmarking Study referred to in the question was prepared by Mercer / Oliver Wyman.

Hydro One has a binding collective agreement with the Power Workers Union until its expiration on March 31st, 2011.

In 2002, Hydro One negotiated a new lower Meter position. The Mercer Compensation study shows that this classification is just 4% above market median for compensation. While the service dispatcher, drafter II, stock keeper and data entry clerk are higher than median, these classification cumulatively represent just 3.7% of the 2008 regular PWU staff complement.

Energy Probe INTERROGATORY #8 List 1

Interrogatory

Ref: Exhibit A, Tab 16, Schedule 2, Attachment 1

This attachment is a compensation and productivity comparison study of Hydro One by Mercer and Wyman. Page 25 presents the work output measures used in the productivity part of the study. One of these, "MWhrs sold" is reportedly included because it "*is a measure of system requirements and activity required on that infrastructure to deliver energy. It impacts wear on the system and levels of capacity.*"

a) Total Km of line and Total Gross Assets account for the transmission lines and transformer stations making up the transmission system. Why is "MWhs sold" a relevant measure when these two measures seem to capture all components of the system?

b) Does Hydro One base its staffing levels on the volume of "MWhs sold"? If not, how is employee compensation related to this measure?

c) How does the amount of "MWhs sold" impact "wear on the system"? Does Hydro One schedule any of its maintenance activities on the number of MWhs sold?

d) Would "MWhs sold" be a measure more relevant to productive use of assets than to employee compensation?

Response

Correction: The Compensation Cost Benchmarking Study referred to in the question was prepared by Mercer / Oliver Wyman.

a) As noted in the Mercer / Oliver Wyman report several measures were used for Work Output. While Total Km and Total Gross Assets represent the size of the physical asset, MWhrs sold is a relevant measure because it represents an additional measure of "output" of the network. Increasing transmission of electricity across the network can add additional requirements on the system, increase the maintenance required, and therefore increase the staffing required to ensure the network operates appropriately. Also refer to the response to part c) below.

b) Staffing levels are determined by overall operational, maintenance and investment requirements on the network. These requirements are affected by the total Work output including load on the system as reflected in MWhs sold**,** the size of the system, Total Km, its value, Total Gross Assets and Service Area.

c) In general, increasing loading leads to increasing equipment wear and degradation, which then requires maintenance levels and/or replacement.

d) This study did not examine measures for "productive use of assets" and therefore does not have a basis for comparing relevancy of particular measures against this issue. However Mercer / Oliver used this measure as part of the compensation study as they considered it a relevant part measure of Work Output in its Productivity Indicator.

Energy Probe INTERROGATORY #9 List 1

Interrogatory

Ref: Exhibit A, Tab 16, Schedule 2, Attachment 1

This attachment is a compensation and productivity comparison study of Hydro One by Mercer and Wyman. Page 27 discusses the design of the productivity part of the study. Two of the measures chosen, Gross Fixed Assets and Km of Line, include both Transmission and Distribution components of the company.

a) Why have Distribution assets and line Kms been included in a study of Transmission productivity?

b) What effect would removing the distribution components of the study have on the results?

c) Why were other measures such as “Cost per Customer served” and “# of Employees per customer served” not considered?

Response

Correction: The Compensation Cost Benchmarking Study referred to in the question was prepared by Mercer / Oliver Wyman.

a) The specific direction provided by the OEB in its Decision With Reasons in EB-2006-0501, dated August 16, 2007, page 33, was with regards to “the filing of a study … concerning Hydro One’s compensation costs and how they compare to those of other regulated transmission and/or distribution utilities. … In the study that Hydro One is preparing, the Board expects it to provide empirical evidence which reveals the relative productivity of its workforce in comparison to other utilities.” The direction provided was to Hydro One Networks as a whole, covering both its Transmission and Distribution businesses, and to compare itself to transmission and/or distribution utilities. The only way to do this correctly would be to include Distribution assets and line Kms in the measures. Further, the participant utilities in the workforce productivity study are largely integrated Transmission/ Distribution companies.

Further, as discussed in evidence, such as Exhibit I, Tab 1, Schedule 35, and Exhibit I, Tab 2, Schedule 10:

> *Hydro One has an integrated workforce for its transmission and distribution businesses. This allows Hydro One to take advantage of economies of scale and efficiencies that would not be available through separate transmission and distribution operations. As a result of its integrated workforce, separate workforce data for Hydro One's Transmission Business only is not available.*

As such, separate Hydro One Transmission workforce data is not available for compensation and workforce productivity benchmarking studies. And on this basis, it would be inappropriate not to include Distribution assets and line kms in a study of Hydro One combined Transmission/Distribution workforce productivity.

Consequently, as described in the report and in various stakeholder sessions, the productivity indicators presented are inclusive of Distribution and Transmission.

b) This study did not and cannot isolate or remove the distribution components; the data is not available to do such. Further, it would be inappropriate to do so as discussed in part a), as most of the participants in the study, including Hydro One, have an integrated Transmission/Distribution workforce and cannot/ did not provide separate Transmission and Distribution workforce information. .

c) As stated in Exhibit I, Tab 1, Schedule 1, a "per customer" measure is not an appropriate normalizer for Transmission measures due to the small numbers of customers and types of customers e.g. a large Local Distribution Company and an individual industrial company that are directly served by the Transmission System. As discussed in parts a) and b) above, this study examined the combined, integrated Transmission/ Distribution workforce, so "per customer" measures were not appropriate.

Energy Probe INTERROGATORY #10 List 1

Interrogatory

Ref: Exhibit A, Tab 16, Schedule 2, Attachment 1

This attachment is a compensation and productivity comparison study of Hydro One by Mercer and Wyman. Page 30 reports the Key Findings of the Productivity part of the study.

a) Does "T&D compensation" per measure reported on this page include customer service costs broken out on pages 36 – 40? If yes, how much of T&D total compensation is for customer service functions?

b) How much weight has Customer Service productivity been given in the overall conclusion stated on page 2 of the report that *"Examining the mix of indicators leads to the conclusion that Hydro One requires less workforce compensation to generate various units of output."*

c) The findings on this page report that Hydro One is "fourth best" out of seven on one measure and "about median" on two others. This seems to say that Hydro One is about median on 3 of the 4 measures. How can this be reconciled with the statement on page 2 of the report that "*All indicators measured ranked better than median (i.e., more productive) except one, which is slightly below median (i.e., less productive)."*

d) If Hydro One is in fact at median on 3 of 4 productivity measures, is the statement in b) above "*that Hydro One requires less workforce compensation to generate various units of output"* accurate?

e) If the answer to v) above is "no it is not accurate" is the conclusion appearing at lines 19-21 of page 3 of the schedule that "*Therefore the positive Hydro One productivity results balance Hydro One's total compensation being above the market median"*, justified?

Response

Correction: The Compensation Cost Benchmarking Study referred to in the question was prepared by Mercer / Oliver Wyman.

a) Customer service costs are not included in Transmission and Distribution compensation.

b) The overall conclusion is not based on a weighting of indicators such as Customer Service productivity. The conclusion is derived from the fact that all of the indicators for Hydro One, except one, are more productive than the median of the peer group.

c) Examining the measures in more detail on pages 31 and 36 of the study shows Hydro One's productivity indicators in comparison to the range and median value of the peer panel. Hydro One's productivity indicators are more productive than the median of the peer panel on all but one of the indicators. This is consistent with the statement on page 2.

d) The statement in the study conclusion is accurate. Hydro One is actually better than median of the peer group on 3 of the 4 productivity indicators for Transmission and Distribution and is better than the median for all of the productivity indicators for Customer Service making the statement in the study conclusion accurate.

e) See d) above.

Energy Probe INTERROGATORY #11 List 1

Interrogatory

Ref: Exhibit C1, Tab 2, Schedule 2, pages 3 – 4

Land Assessment and Remediation (line 26) refers to "*historical contamination located both inside and outside the station fence*".

a) What does this contamination consist of?

b) Does Hydro One have a complete inventory of historical contaminated sites?

c) How long does Hydro One expect to need to remediate these sites?

d) What distinguishes "historical contamination" from contamination considered under Environmental Management?

Response

a) As indicated in Exhibit C1, Tab 2, Schedule 2, Page 7 of 51, lines 16 and 17: "The primary contaminants of concern are Arsenic, PCBs, petroleum hydrocarbons and the wood pole preservative pentachlorophenol (PCP)."

b) Yes.

c) The Land Assessment and Remediation (LAR) program is expected to be completed by 2017.

d) Historical contamination resulted from the operations of the previous Ontario Hydro. Environmental contamination resulting from the current operations of Hydro One is managed under Environmental Management.

Energy Probe INTERROGATORY #12 List 1

Interrogatory

Ref: Exhibit C1, Tab 2, Schedule 2, page 9

a) What is Hydro One's plan for eliminating PCBs from its equipment?

b) The dangers of PCBs have been known for decades. Why has Hydro One not taken steps over the last 20 years to eliminate them from its system?

Response

a) Please see exhibit A, Tab 13, schedule 1, Page 8 of 9 section 4.4.1 Federal Legislation for details. Hydro One is currently developing plans to comply with the latest version of the legislation that was published by the Federal government on September 17, 2008. Please see Interrogatory Exhibit I, Tab 1, Schedule 23 for our plan development.

b) Hydro One has maintained compliance with all relevant PCB legislation. Hydro One maintains a standards and procedures manual for handling PCBs and PCB contaminated materials and wastes within legal requirements.

Energy Probe INTERROGATORY #13 List 1

Interrogatory

Ref: Exhibit C1, Tab 2, Schedule 2, page 11

a) What is required to replace "sheet plastic spill containment liners" described at line 2?

b) How much does a typical containment pit relining cost?

c) Why does Hydro One leave abandoned oil piping systems in the ground? Why are they left with residual oil in them? What options does Hydro One have for flushing these systems to eliminate residual oil?

Response

a) Hydro One does not replace plastic spill containment liners with plastic spill containment liners. Instead the pit is rebuilt using reinforced concrete pit, which is a technically and environmentally superior solution. The following tasks are required to replace a sheet plastic spill containment liner:
- Excavation of the gravel around the transformer,
- Removal of the existing plastic liner. In some cases the removal of the original clay liner may be warranted.
- Install new piping to the spill containment pit
- Install a concrete spill containment pit complete with sensors, pumps and oil/water separators.

b) A typical containment pit relining project could cost $500,000 per pit. Most sites have an average of three pits.

c) Abandoning underground pipelines containing residual oil at Hydro One stations was a historical practice that is no longer acceptable given Hydro One's mandate for environmental stewardship. Hydro One's long term goal is to remove all residual oil from underground piping at all stations. Hydro One developed this program so that this unused piping is being cleaned by drainage and subsequent vacuum swabbing.

Energy Probe INTERROGATORY #14 List 1

Interrogatory

Ref: Exhibit C1, Tab 2, Schedule 2, page 14

Starting at line 23, reference is made to "*An increasing number of power equipment assets, such as power transformers and circuit breakers, are entering their midlife and end of life regions*".

a) Figure 1 on page 15 for power transformers appears to show that the number of power transformers entering midlife is remaining constant at about 500. Please explain the apparent contradiction with the statement on page 23.

b) Figure 2 on page 16 for circuit breakers shows the number of units entering midlife declining in 2008 and 2009 compared to 2007 and the number in 2010 seems to be the same as 2007. Please explain the apparent contradiction with the statement on page 23.

c) According to Figure 1 on page 15, the number of power transformers in the midlife and EOL categories appears to increase by about 50 units over the period 2007 to 2010 or about 7%. Figure 2 on page 16 shows the number of circuit breakers in the midlife and EOL categories over the same period increasing by about 300 units or 8.6% above the 2007 population. The budget for stations shown in Table 2 of page 5 of the exhibit, however, shows an increase in expenditure of $22 M in 2010 compared to 2008 levels. This represents about 36% increase. Please explain why such a dramatic increase in expenditures is required to deal with the relatively modest increase in the EOL population and the stable population of midlife power transformers and circuit breakers.

Response

a) The subject statement is not contradictory as it refers to the combined total of power transformers entering mid life and end of life regions. However, the increase is primarily due to assets entering end of life region.

b) The subject statement is not contradictory as it refers to the combined total of circuit breakers entering mid life and end of life regions. However, the increase is primarily due to assets entering end of life region.

c) The number of assets in the mid life and end of life regions is only a leading indicator, not a driver for the increase in expenditures. The increase in expenditures is driven by changing maintenance requirements and the mix of assets requiring maintenance, which attract maintenance work differently. Examples of specific increases in maintenance activity include:

- Increased intensity in the 750 MVA autotransformers remediation program
- Increased preventative maintenance for oil and air blast circuit breakers
- Increased intensity for the air blast circuit breaker refurbishment program
- Increased corrective maintenance which has been trending higher as the assets age

Energy Probe INTERROGATORY #15 List 1

Interrogatory

Ref: Exhibit C1, Tab 2, Schedule 2, page 18

This page references a program called "Cyber Security" which is required by NERC Critical Infrastructure Protection (CIP) Standards.

a) When were the NERC standards referred to at lines 1-4 developed?

b) What comparable security program existed at Hydro One prior to the NERC requirements?

Response

a) These standards were developed over several years, culminating in approval by the NERC Board of Trustees in 2006. The NERC standards are now enforceable in Ontario according to the NERC implementation plan for each standard. The implementation plan for the NERC CIP standards requires Hydro One to be compliant by the end of 2009.

b) Hydro One already had put in place many physical and electronic security provisions as part of the design of the Ontario Grid Control Centre.

Energy Probe INTERROGATORY #16 List 1

Interrogatory

Ref: Exhibit C1, Tab 2, Schedule 2, pages 27 – 28

Starting at line 6 on page 27 the following statement appears:

> "*Many ancillary systems are of the same vintage as the power equipment they serve and therefore share the same age demographics as previously discussed for transformer and breaker assets. Consequently, the number of ancillary system assets entering the EOL region in the test years is increasing*"

Line 27 on the same page states:

> *"The spending requirement for test year 2009 is $18.2 million, which is an increase of31% over the projected spending in the bridge year 2008. The 2010 spending is $21.0 million, which is an increase of 15% over the 2009 test year. The increase in test year spending is largely due to the increased maintenance and mid-life refurbishment of ancillary systems moving through their mid-life region."*

a) Please provide a chart similar to Figure 1 on page 15 of the schedule showing the number of pieces of ancillary equipment entering midlife and EOL categories.

b) If the age distribution of ancillary systems is similar to power equipment, this would suggest a relatively stable number of components entering midlife and an increase in EOL components of 7-8%. Please explain why required expenditures are 31% higher in 2009 and 51% higher in 2010 than the test year if increases in equipment needing maintenance are only 7-8%.

Response

a) Please see response to Interrogatory Exhibit I, Tab 6, Schedule 28 (c) which shows the percent of representative ancillary system assets in the mid life and end of life regions.

b) Ancillary system spending is largely driven by power equipment spending, for which increased spending is discussed in Interrogatory response Exhibit I, Tab 8, Schedule 14 (c).

Energy Probe INTERROGATORY #17 List 1

Interrogatory

Ref: Exhibit C1, Tab 2, Schedule 2, pages 33 – 34

This section of the schedule describes Vegetation Management requirements for ROW maintenance. Starting at line 11 on page 34 the following statement is made:

> *"The activities of brush control and line clearing must comply with the new requirements of the NERC Vegetation Management Standard that came into effect during 2006."*

a) How did the NERC standard differ from that in effect at Hydro One prior to 2006?

b) How much of the increased cost of vegetation management in 2007 was the result of the NERC standard and how much was attributable to other causes?

c) Why is the Bridge year spending shown in Table 5 on page 33 significantly lower than historic year spending?

Response

Please refer to Exhibit I, Tab 1, Schedule 25 for an explanation of the impact of the new NERC vegetation management standard and for the variance explanations.

Energy Probe INTERROGATORY #18 List 1

Interrogatory

Ref: Exhibit C2, Tab 3, Schedule 1, page 1

Reference is made on this page to a "six year apprenticeship" for Regional Lines Maintainers.

a) Please explain why this apprenticeship is two years longer than a typical distribution utility line maintainer.

b) Are all Hydro One line maintainers equally qualified to work on both distribution and transmission line voltages?

c) If not, are there wage and benefit differences between those who work on transmission lines and those who work only on distribution lines?

Response

a) A Regional Lines Maintainer has completed a 4 year Power Line Technician Apprenticeship. Once selected to a regular position with Hydro One, they receive a further 2 years of training before they are placed at the top step of the Regional Maintainer classification.

b) Approximately 45% of our Regional Maintainers are equally proficient on Transmission or Distribution assets. All other Regional Maintainers have basic Transmission training.

c) All Regional Maintainer Lines are paid on the same salary scale and receive the same benefits.

Energy Probe INTERROGATORY #19 List 1

Interrogatory

Ref: Exhibit D1, Tab 1, Schedule 1, page 3

Table 2 on this page shows fixed asset retirements declining over the test period. This appears to be at odds with the reasoning offered for increased maintenance costs in Exhibit C1, Tab 2, Schedule 2, page 14 that "*An increasing number of power equipment assets, such as power transformers and circuit breakers, are entering their midlife and end of life regions*".

Please explain the apparent inconsistency that more equipment reaching end of life does not result in increased asset retirements.

Response

The statement in italics refers to the fact that an increasing number of power equipment assets are entering the end-of-life region, which does not necessarily mean these assets are at end of life and are being replaced.

The increase in assets in the end-of-life region is indicative of the increasing need to replace these assets in future years, but as discussed in Exhibit D1, Tab 3, Schedule 2, page 6, the combined Sustainment capital spending in 2009 and 2010 on power equipment (i.e. Circuit Breakers, Station Re-Investment, and Power transformers) is flat.

Asset retirements in the test years are higher relative to 2005 and 2006, as would generally be expected, but there isn't a direct relationship between the increase in Sustaining capital replacements and the total amount of asset retirements. The volume of asset retirements will vary as a result of the mix of assets being replaced in a particular year (e.g. the large volume of asset retirements in 2007 is attributable to significant replacement of the Microwave telecommunication system).

Energy Probe INTERROGATORY #20 List 1

Interrogatory

Ref: Exhibit D1, Tab 2, Schedule 1, Attachment A

Figure 4.1 on page 21 of this report shows the Health Index Results for Power Transformers. Figure 4.2 on page 24 shows the Health Index Results for Air Blast Breakers. Those falling into the "Good" and "Very Good" condition categories comprise respectively 9% and 87% of the total population of transformers. The comparable figures for Air Blast Breakers are 27% and 67%. Recommended maintenance for equipment in these categories is shown on page 10 of the report as "*Normal inspection and maintenance*". The fact that most equipment in this category (96% for Power Transformers and 94% for Air Blast Breakers) requires only normal maintenance appears to be inconsistent with the requirement in Exhibit C1, Tab 2, Schedule 2, for increased maintenance of these devices over the test period.

a) Please explain this apparent inconsistency.

b) Does Hydro One have studies or analyses that correlate maintenance requirements for major station components such as transformers and breakers with age of these components? If so, please provide them. If not what is the basis for correlating maintenance requirements with age of equipment?

Response

a) There is no inconsistency. Please see response to interrogatory Exhibit I, Tab 6, Schedule 51.

b) No, Hydro One does not have studies that correlate maintenance requirements for major station components with age. However, experience indicates that aging equipment requires more maintenance to achieve the desired equipment performance. Age is not the deciding factor for maintenance or capital programming at Hydro One.

Energy Probe INTERROGATORY #21 List 1

Interrogatory

Ref: Exhibit D1, Tab 2, Schedule 1, Attachment A

On page 23 the following statement is made in the section devoted to Oil Circuit Breakers:

> "*Since 2004 Networks has had a program to replace all of the OCBs on its system which is an overriding strategy driven by technical obsolescence, that does not involve the use of asset condition assessment or a health index calculation. In such cases it is in keeping with industry best practices to not conduct Asset Condition Assessments where asset sustainment is not considered to be an investment driver.*"

a) Please confirm that this is an accurate statement.

b) What proportion of circuit breakers is being replaced each year?

c) When does Hydro One expect to have the replacement program completed?

d) If all OCBs are scheduled for replacement, how should this be reconciled with the requirement for increased maintenance of OCBs proposed in Exhibit C1, Tab 2, Schedule 2?

Response

a) This statement is accurate.

b) Please see Interrogatory response Exhibit I, Tab 1, Schedule 53.

c) Please see Interrogatory response Exhibit I, Tab 1, Schedule 53.

d) Oil circuit breakers will remain on Hydro One's system for some time as indicated in the response to Interrogatory Exhibit I, Tab 1, Schedule 53. These breakers will need planned and corrective maintenance to maintain the required performance until they are removed from the system.

Energy Probe INTERROGATORY #22 List 1

Interrogatory

Ref: Exhibit D1, Tab 3, Schedule 2, page 18

Table 4 shows replacement of Air Blast Breakers at Nanticoke TS. In light of the Government's plan to shut down Nanticoke GS and the recent approval from the Ontario Energy Board of Hydro One's application to construct a new 500 kV line from Bruce to Milton:

a) What, if any, are the expected impacts on Nanticoke TS of these two developments?

b) Has Hydro One considered these impacts in its capital spending plans for Nanticoke TS?

Response

a) The Nanticoke TS switchyard will continue to be a major hub for the 230 / 500 kV systems. Thus, the planned shut down of the generation at Nanticoke GS does not impact the planned refurbishment at Nanticoke TS. In addition to providing a major network path, the 230 kV circuits from Nanticoke TS supply several load stations and large customers. Details of the Nanticoke TS refurbishment project are shown in Exhibit D2, Tab 2, Schedule 3, Page 8 of 80, reference S7.

The planned shutdown of Nanticoke GS and the new 500 kV line from Bruce to Milton are expected to require additional VAR support to be installed at Nanticoke TS as well as two other stations. Details of the VAR support project are shown in Exhibit D2, Tab 2, Schedule 3, Page 40 of 80, reference D3.

b) Yes. Hydro One has fully considered the impacts of these plans on its work at Nanticoke TS as described in part a).

Energy Probe INTERROGATORY #23 List 1

Interrogatory

Ref: Exhibit D1, Tab 3, Schedule 2, page 5

Table 2 lists the capital expenditures for various station components. The most significant increases occur in the first three categories of Circuit Breakers, Station Re-investment, and Power Transformers. Summing these categories it appears that the Bridge Year expenditure would be $116 M, the 2009 test year expenditure would be $127 M and the 2010 test year would be $126 M. These amounts are significantly greater than each of the historical years in which expenditures were $49 M in 2005, $50 M in 2006 and $68 M in 2007.

Please explain why capital expenditures to replace EOL power equipment over the bridge and test years appears to be doubling compared to historical years while increases in power equipment reaching EOL appear to be in the 30% range for circuit breakers (per figure 4 page 11) and the 20% range for transformers (per figure 6 page 21).

Response

The number of assets in the end of life region is a leading indicator, not a driver for the increase in expenditures. Assets are deemed to be at their end of life based on condition and performance data.

The investment in transformer, breaker and ancillary replacements for 2009 and 2010 manages short term risks and costs within the overall prioritized investment plan for Hydro One Transmission and accommodates the replacement of the highest risk assets.

Energy Probe INTERROGATORY #24 List 1

Interrogatory

Ref: Exhibit D1, Tab 3, Schedule 2, page 36

This page describes Cyber Security Readiness requirements. Expenditures are forecast to be mainly in 2008 with the balance of spending required to comply with NERC standards occurring in 2009. Spending on Cyber security in 2010 amounts to $6.4 M but appears to be related to FERC proposals.

a) What do the Cyber Security readiness requirements consist of?

b) If new systems are needed, do they replace or augment existing systems?

c) Is Hydro One subject to FERC requirements in the area of cyber security?

d) If not, why would Hydro One elect to exceed NERC requirements?

Response

a) The NERC Critical Infrastructure Protection requirements are publicly available on the NERC website. In summary, the compliance program covers the creation of electronic security perimeters and firewalls, access controls, malware detection, configuration change control, intrusion detection, incident logging, recovery capabilities, securing the technical information about the Critical Cyber Assets as well as personnel training program.

b) New systems are needed and they augment existing systems.

c) Hydro One is not subject to FERC requirements but is subject to NERC requirements. NERC is heavily influenced by FERC as it is FERC that approves the NERC standards in the US. The standards developed by NERC are approved by the OEB in Ontario.

d) Hydro One has developed a plan aligned with direction provided by FERC because we believe, for the reasons stated above, that this will be the future direction of the NERC standards.

Energy Probe INTERROGATORY #25 List 1

Interrogatory

Ref: Exhibit D1, Tab 3, Schedule 2, page 52

Table 13 provides details of the Overhead Lines Refurbishment and Component Replacement program. Removal Cost is subtracted from the total cost to arrive at the net Capital Cost.

a) Please explain why removal costs are not considered part of the Capital Cost of a project.

b) Where are removal costs charged? Where do they show in the evidence?

Response

a) Under Canadian Generally Accepted Accounting Principles (GAAP), fixed asset removal costs do not qualify as fixed assets as they are not considered to be an attributable cost of the replacement asset. As removal costs do not result in future economic benefits to the enterprise, they must be treated as period costs.

b) Fixed asset removal costs are reported as part of depreciation expense. The Asset Removal Costs are shown in Exhibit C2, Tab 5, Schedule 1, line 5.

Energy Probe INTERROGATORY #26 List 1

Interrogatory

Ref: Exhibit D1, Tab 3, Schedule 3, page 14

Project D4 is to modify the Bruce Special Protection System in order to accommodate return to service of Bruce Units until the new 500 kV circuits to Milton are in service.

a) When are the Bruce units referenced scheduled to return to service?

b) Is the preparation work on these units to return to service on schedule?

c) If the units do not return to service before the new 500 kV line is in place, will the cost of modifying the Special Protection System be stranded?

d) If the answer to iii) is Yes, can Hydro One recover its costs for this project from Bruce Power?

Response

a) In its latest 18-month outlook[1], the IESO forecasts return to service dates for these as 2009-Q3 for unit 2 and 2010-Q1 for unit 1.

b) The relatively minor work that Hydro One has to execute to facilitate the return to service of these units is on schedule. Hydro One cannot comment on the status of the work at Bruce Power.

c) No. The modifications to the Bruce Special Protection System are also required to facilitate the transmission outages that will be necessary to construct the new 500 kV Bruce to Milton line.

d) Not applicable.

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[1] 18-Month Outlook - An Assessment of the Reliability of the Ontario Electricity System - From October 2008 to March 2010, IESO_REP_0480v1.0, September 23, 2008. http://www.iemo.com/imoweb/pubs/marketReports/18MonthOutlook_2008sep.pdf

Energy Probe INTERROGATORY #27 List 1

Interrogatory

Ref: Exhibit D2, Tab 2, Schedule 3
Exhibit D1, Tab 3, Schedule 3

Project D38 in the first reference is an Investment Summary Document for the connection of the Lower Mattagami upgrading projects of OPG. The net cost to Hydro One is noted as $19.0 M in Table 5 on page 36 of Exhibit D1, Tab 3, Schedule 3. This project is currently under environmental assessment review.

a) Hydro One has budgeted $6.9 M to be spent in 2009. How has Hydro One anticipated the uncertainty of the outcome of the Environmental Assessment process currently under way for the Lower Mattagami projects?

b) If the Lower Mattagami projects are not approved in the EA process, what recourse does Hydro One have to recover its costs on the transmission connection?

Response

a) Funds for this project will only be released and spent after the Connection and Cost Recovery Agreement (CCRA) between OPG and Hydro One is signed. Any risk associated with the outcome of the EA process will be assumed by OPG.

b) The CCRA will require that OPG compensate Hydro One for any work performed to date of termination or cancellation by OPG and all the incurred cost associated with winding up the work.

Canadian Manufacturers & Exporters (CME) INTERROGATORY #1 List 1

Interrogatory

General – Issues 1.1

Ref: Exhibit A, Tab 2, Schedule 1, paragraph 3
Exhibit A, Tab 3, Schedule 1, page 3
Exhibit A, Tab 1, Schedule 1, pages 1 to 6

1. The revenue requirement requested for 2009 is $1,232.7M and $1,341.0M for 2010. The Board approved revenue requirement for 2008 is $1,170.0M. The 2009 over 2008 revenue deficiency is about $62M or 5.3% of the 2008 Board approved revenue requirement. The 2010 over 2009 revenue requirement increase is $108M or about an 8.6% increase in the requested 2009 revenue requirement of $1,233M. According to the evidence, the 5.3% increase in revenue requirement between 2008 and 2009 translates into an increase in rates of 6.4% and the 8.6% increase in the 2010 requested revenue requirement over 2009 translates into a 12.1% increase in 2010 rates over 2009 rates. The evidence indicates that a 6.4% increase in rates in 2009 results in an estimated total customer bill impact of 0.8% and that a 12.1% increase in 2010 rates over 2009 rates results in an estimated 1.6% impact on a customer's total bill. In the context of this evidence, we request the following additional information:

   (a) Please list, describe, and quantify, if possible, each of the major factors that explain why the percentage increases in rates for 2009 over 2008 of 6.4%, and for 2010 over 2009 of 12.1% materially exceed the percentage increase in the corresponding revenue requirement amounts of 5.3% and 8.6% respectively.

   (b) Please show how the total customer bill impacts of 0.8% for 2009 over 2008, and 1.6% for 2010 over 2009 have been derived, and include in the total amount of the customer bills used in this calculation all of its separate components, such as distribution charges, energy charges, global adjustment, etc.

   (c) Please calculate the 2009 and 2010 revenue deficiency amounts on the basis of a Price Cap escalator applicable to Hydro One's Board approved 2008 Transmission Rates of 1.5% plus the amount that results from applying the Incremental Capital Module which the Board approved as part of the 3rd Generation Incentive Regulation Mechanism for electricity distributors so that these revenue requirement calculations can be used as comparators when considering the appropriateness of the overall revenue requirements for 2009 and 2010 which Hydro One asks the Board to approve.

Response

(a) The table below details the difference between the percentage increases in revenue requirement and the required rate change.

2008 to 2009

Rates revenue requirement should be used when calculating the increase in revenue requirement compared to the increase in rates. Revenue requirement increases 5.3% from 2008 to 2009, while rates revenue requirement increases by 5.5% over the same period. The estimated impact of load reduction of 0.9% on rates revenue requirement results in a rate increase required of 6.4%.

Description	2008 (a)	2009 (b)	Difference (c) = (b)-(a)	Change (d) = (c)/(a)
Revenue Requirement *	1,170	1,233	62	5.3%
Rates Revenue Requirement *	1,137	1,199	62	5.5%
** EB-2008-0272, Exhibit E1, Tab 1, Schedule 1, Table 2*				
Estimated Impact of Load Reduction				0.9%
Total Rate Change Required	= 5.5% + 0.9%			**6.4%**

2009 to 2010

Rates revenue requirement should be used when calculating the increase in revenue requirement compared to the increase in rates. Revenue requirement increases 8.8% from 2009 to 2010, while rates revenue requirement increases by 9.2% over the same period. The estimated impact of load reduction of 2.9% on rates revenue requirement results in a rate increase required of 12.1%.

b) The pre-filed evidence has been updated and the customer bill impacts are 0.5% for 2009 over 2008 and 0.9% for 2010 over 2009 as stated in the Notice of Application for this proceeding.

The derivation of the customer bill impacts is based on the Transmission Rate Impact multiplied by the estimated share of transmission costs as a percentage of the total cost of electricity.

The estimated total cost of electricity is described below.

Cost Component	**Estimated Costs (¢/kWh)**	**Source**
Commodity	5.78	IESO August 2008 Monthly Market Report page 26
Wholesale Market Service charge	0.58	IESO August 2008 Monthly Market Report page 26
Wholesale Transmission Charge	0.71	As above adjusted for 9.2% increase in Transmission rates effective January 1 2009 (0.65 ¢/kWh*1.092)
Debt Retirement Charge	0.7	IESO August 2008 Monthly Market Report page 26
Distribution Services Charge	1.87	$2.78 billion per OEB 2007 Yearbook page 7/ 148 TWh sales (per IESO data)
Total	**9.64**	

The share of transmission costs as a percentage of total cost is **7.4**%, (0.71¢/kWh /9.64¢/kWh).

The 2009 Transmission Rate Impact is estimated at **6.4**% and for 2010 it is estimated at **12.1**%, (Exhibit A, Tab 3, Schedule 1, page 3).

Therefore, the estimated 2009 customer impact is 0.5% (7.4%*6.4%) and the estimated 2010 customer impact is 0.9% (7.4%*12.1%).

c) As outlined in the question, the data requested is to be created as per the OEB’s 3G IRM model for LDC’s. However, this mechanism is not applied by the OEB to Transmitters, it is only applied to LDC’s. As such, it would be inappropriate to generate such data for Hydro One Transmission using the LDC 3G IRM model. Further, the question is incorrect in that the 3G IRM model is NOT applied to Revenue Requirement, rather it is applied to rates.

Consequently, for these reasons the requested data cannot be provided.

Canadian Manufacturers & Exporters (CME) INTERROGATORY #2 List 1

Interrogatory

General – Issues 1.1

Ref: Exhibit E, Tab 1, Schedule 1, Tables 3 and 5

2. A "Change in Load Forecast" of $6M is identified as a component of the $62M revenue deficiency for 2009 over Board approved 2008 in Table 3 found at Exhibit E1, Tab 1, Schedule 1, page 4, and "Change in Load Forecast" is identified as a $36M contributor to the $110M revenue deficiency for 2010 over 2009 at Table 5 found at Exhibit E1, Tab 1, Schedule 1, page 6. In the context of this information, we request the following:

   (a) Please provide detailed calculations showing how the amounts of each of the "Change in Load Forecast" contributors to revenue deficiency were calculated.

Response

Detailed calculation of the change in gross change in load forecast provided below:

	Hydro One Charge Determinants (avg monthly MW)								
	2008 *Note 1*	**2009** *Note 2*	**2010** *Note 2*	Difference 2008 to 2009	Difference 2009 to 2010	Current Tx Rates ($/kW) *Note 3*	2009 Revenue Impact ($M)	Estimated 2009 Tx Rates ($/kW)	2010 Revenue Impact ($M)
Tx Service	a	b	c	d=b-a	e=c-b	f	g=d*12*f/1000	h=f*(1+6.4%) x(1-d/a)	i=e*12*h/1000
Network	21,144	20,842	20,199	(302)	(643)	2.57	(9)	2.77	(21)
Line Connection	20,199	20,100	19,555	(99)	(545)	0.70	(1)	0.75	(5)
Transformation Connection	17,365	17,376	16,905	11	(471)	1.62	0	1.72	(10)
						Revenue Deficiency Due to Gross Change in Load:	**($10M)**		**($36M)**

Note 1: Per Schedule 3.1 of OEB Order in EB-2006-0501
Note 2: Per Table 1 of Exhibit H1, Tab 3, Schedule 1
Note 3: Per Current Uniform Transmission Rate Schedule issued October 17, 2007

Included in the net change in load forecast is the change in external revenues. The approximate change to external revenues in 2009 is +$5M and in 2010 is +$1M (see Table 2 and 4 in Exhibit E1, Tab1, Schedule 1, line no 6). The addition of the gross change in load forecast calculated in the table above together with the change in external revenues results in the approximate $6M and $36M change in load forecast for 2009 and 2010 respectively.

Canadian Manufacturers & Exporters (CME) INTERROGATORY #3 List 1

Interrogatory

Operating Maintenance and Administration ("OM&A") – Issues 3.1 to 3.4

Ref: Exhibit A, Tab 3, Schedule 1, page 4
Exhibit C, Tab 1, Schedule 1
Exhibit C, Tab 2, Schedule 1

3. Hydro One asks the Board to approve total OM&A for 2009 of $435.2M and for 2010 of $449.7M. These amounts are up from the 2008 Board approved OM&A of $387.5M and Hydro One's estimated actual 2008 OM&A of $402.7M. In the context of this evidence, please provide the following information:

   (a) Please describe how Hydro One would alter its 2009 and 2010 OM&A budgets and spending to manage its OM&A expenditures in those years in the event that the Board were to adopt an envelope approach to assessing the reasonableness of Hydro One's OM&A budgets and were to approve total OM&A budgets in each of the years 2009 and 2010 in amounts of $10M less, $15M less, and $20M less than the total amounts Hydro One asks the Board to approve in each of the years 2009 and 2010.

Response

(a) Please refer to Hydro One's response provided at Exhibit I, Tab 1, Schedule 10 with respect to project and program reprioritization.

Canadian Manufacturers & Exporters (CME) INTERROGATORY #4 List 1

Interrogatory

Capital Expenditures and Rate Base – Issues 4.1 to 4.3

Re: Exhibit A, Tab 3, Schedule 1, page 3
Exhibit D, Tab 1, pages 1 and 2

4. The evidence indicates that Hydro One is budgeting total capital expenditures in 2009 of about $944M and in 2010 of about $1,074.1. Each amount is significantly higher than the Board approved capital budget for 2008 of $774.4M. In the context of this evidence, please provide the following information:

   (a) Please describe how Hydro One would alter its capital budgets and spending priorities in 2009 and 2010 in the event that the Board were to adopt an envelope approach to Hydro One's requested capital budgets for 2009 and 2010 and were to approve total capital budgets in each of the years 2009 and 2010 in amounts of $50M, $100M and $150M less than the amounts requested by Hydro One.

Response

(a) Please refer to Hydro One's response provided at Exhibit I, Tab 1, Schedule 10 with respect to project and program reprioritization.

Canadian Manufacturers & Exporters (CME) INTERROGATORY #5 List 1

Interrogatory

Capital Expenditures and Rate Base – Issues 4.1 to 4.3

Ref: Exhibit A, Tab 3, Schedule 1, page 6 re: Facilities for New Renewable Generation

5. What portion of the capital and operating budgets for 2009 and 2010 pertain to the development, construction, ownership and operation of enabler facilities for renewable resource clusters to serve new renewable resource electricity generators?

Response

The expenditures planned by Hydro One for enabler facilities are for pre-engineering only. Per Exhibit C1, Tab 2, Schedule 3, Section 3.0, these expenditures are proposed to be captured in a variance account and Hydro One is not seeking to recover these costs as part of its revenue requirement in this submission.

Canadian Manufacturers & Exporters (CME) INTERROGATORY #6 List 1

Interrogatory

Capital Expenditures and Rate Base – Issues 4.1 to 4.3

Ref: Exhibit A, Tab 3, Schedule 1, page 6 re: Facilities for New Renewable Generation

6. In its Notice of Proposed Amendments (the "Notice") to the Transmission System Code (the "Code") dated October 29, 2008, the Board indicates that it intends to implement the hybrid option for constructing, owning, operating and eventually connecting enabler facilities for renewable resource clusters to new renewable resource electricity generators. The Notice indicates that once these new generators have been connected to the Transmission System, they will be required to pay their fully allocated share of the costs incurred by the transmitter to construct, own and operate the enabler facilities. In the context of the foregoing, please provide the following information:

   (a) How does Hydro One propose to calculate the carrying costs they incur with respect to the construction, ownership and operation of enabler facilities for new renewable generation? In particular, is Hydro One seeking a full rate of return on costs incurred with respect to such enabler facilities or something less than a full return such as the Allowance for Funds Used During Construction ("AFUDC")?

   (b) What measures does Hydro One envisage it will apply to track all of the costs it incurs with respect to the construction, ownership and operation of enabler facilities so that those costs can be assigned to renewable resource generators as they are connected?

   (c) How does Hydro One envisage that renewable resource generators will discharge their cost responsibility for enabler facilities when they eventually become connected to the Transmission System? Will they be called upon to make a one time payment, or will their cost responsibility for enabler facilities be discharged gradually?

   (d) How does Hydro One envisage that its transmission revenue requirement recoverable in rates will be adjusted as renewable resource generators are attached to the system?

   (e) Does Hydro One subscribe to the principle that all of the owning and operating costs of enabler facilities incurred by transmitters, including all of the carrying costs thereon incurred between the outset of construction of such facilities and the points in time when new generators are attached should eventually be fully assigned to the new renewable generators?

Response

(a) Hydro One notes that the Board's proposed amendments to the Transmission System Code are yet to be finalized. Additionally, the Board has stated (in its October 29, 2008 Notice of Proposed Amendments) that implementation of the hybrid option will involve a number of steps or processes, including "a rates process to deal with the costs of the enabler facility". Hydro One expects to calculate and seek recovery of the costs of enabler facilities, including the allowed return and carrying costs, in accordance with the Transmission System Code, once it is amended, and based on any rules or guidelines that the Board chooses to issue in this respect.

(b) Based on the proposed amendments, Hydro One expects to track the costs of enabler facilities using the same project costing and accounting policies, processes and systems that it uses for tracking the construction, ownership and operation of other transmission assets and for assigning those costs to the appropriate rate pools.

(c) Hydro One expects that the amended Transmission System Code and any associated rules and guidelines from the Board will prescribe the manner by which generators would discharge their cost responsibility for enabler facilities.

(d) Hydro One anticipates that the rates process noted in (a) above, possibly accompanied by other direction from the Board, will prescribe the mechanism for adjusting the transmitter's revenue requirements for the costs associated with enabler facilities.

(e) Hydro One participated in the Transmission Connection Cost Responsibility Review and has made a number of submissions in that proceeding. The Board recently issued its proposed amendments dealing with enabler facilities, and the Company plans to comply with the Board's final decisions for cost responsibility and with the requirements of the Transmission System Code.

Canadian Manufacturers & Exporters (CME) INTERROGATORY #7 List 1

Interrogatory

Deferral/Variance Accounts – Issue 5.2

Ref: Exhibit F1, Tab 1, page 1

7. Hydro One seeks continuation of the pension cost differential deferral account. In this context, please provide the following information:

   (a) Please indicate the extent to which the significant drop in the market value of pension plan investments will be attributable to ratepayers through the operation of the provisions of this deferral account.

Response

The current Pension Cost Differential account is intended to capture differences between estimated pension costs for rate setting purposes up to June 30, 2009 and actual pension costs, where actual pension costs are influenced by the level of base pensionable earnings. As these pension costs are estimated based on the actuarial valuation as at December 31, 2006 the current decline in the market value of pension plan investments does not impact this deferral account.

The Pension Cost Differential deferral account requested will commence July 1, 2009. However the next actuarial valuation is not required until December 31, 2009, at which time the current decline in market value of pension plan investments, and any subsequent changes in the level of investment earnings, will be incorporated.

Canadian Manufacturers & Exporters (CME) INTERROGATORY #8 List 1

Interrogatory

Rate Design and Customer Bills

Ref: Exhibit H1, Tab 2, Schedule 1, Tables 1 and 2
Exhibit H2, Tab 1, Schedule 1
Exhibit H2, Tab 2, Schedule 1

8. Please provide sample bills for the typical or average of the 430 LDC Customers; the typical or average of the 92 End-Use Customers, and the typical or average of the 85 Transmission Connected Generators shown in Tables 1 and 2 Exhibit H1, Tab 2, Schedule 1 at page 3 and 4.

Response

The following information was provided by the IESO.

a) Representative LDC Transmission Customer

The following table provides a sample invoice of typical wholesale charges for a representative LDC customer.

Charge Type	Description	Amount
101	Net Energy Market Settlement for Non-Dispatchable Load	$4,765,691.10
102	TR Clearing Account Credit	-$0.32
142	Regulated Price Plan Settlement Amount	-$161,239.01
146	Global Adjustment Settlement Amount	$300,509.29
149	Regulated Price Plan Retailer Settlement Amount	-$2,183.38
150	Net Energy Market Settlement Uplift	$126,629.20
155	Congestion Management Settlement Uplift	$70,712.75
169	Station Service Reimbursement Debit	$2,132.74
170	Local Market Power Rebate	-$8,464.25
183	Generation Cost Guarantee Recovery Debit	$9,877.19
186	Intertie Failure Charge Rebate	-$5,484.19
250	10-Minute Spinning Market Reserve Hourly Uplift	$4,504.18
252	10-Minute Non-Spinning Market Reserve Hourly Uplift	$5,368.41
254	30-Minute Operating Reserve Market Hourly Uplift	$4,423.81
450	Black Start Capability Settlement Debit	$697.42
452	Reactive Support and Voltage Control Settlement Debit	$5,631.80
454	Regulation Service Settlement Debit	$20,656.21
550	Must-Run Contract Settlement Debit	$58,025.16
650	Network Service Charge	$395,809.26
651	Line Connection Service Charge	$102,718.41

Charge Type	Description	Amount
652	Transformation Connection Service Charge	$231,769.16
753	Rural Rate Settlement Charge	$87,011.94
754	OPA Administration Charge	$34,021.67
900	GST Credit	-$10,053.49
950	GST Debit	$315,970.95
	Total	**$6,424,258.55**

b) Representative End-use Transmission Customer

The following table provides a sample invoice of typical wholesale charges for a representative end-use transmission customer.

Charge Type	Description	Amount
100	Net Energy Market Settlement for Generators and Dispatchable Load	$686,120.73
101	Net Energy Market Settlement for Non-Dispatchable Load	$667,421.33
102	TR Clearing Account Credit	-$0.11
105	Congestion Management Settlement Credit for Energy	-$19,891.03
107	Congestion Management Settlement Credit for 10 Minute Non-Spinning Res	-$13.19
146	Global Adjustment Settlement Amount	$93,252.66
150	Net Energy Market Settlement Uplift	$36,900.44
155	Congestion Management Settlement Uplift	$19,072.71
169	Station Service Reimbursement Debit	$663.51
170	Local Market Power Rebate	-$2,633.29
183	Generation Cost Guarantee Recovery Debit	$3,072.86
186	Intertie Failure Charge Rebate	-$1,768.45
202	10-Minute Non-Spinning Reserve Market Settlement Credit	-$44,707.55
250	10-Minute Spinning Market Reserve Hourly Uplift	$1,207.58
252	10-Minute Non-Spinning Market Reserve Hourly Uplift	$1,470.18
254	30-Minute Operating Reserve Market Hourly Uplift	$1,151.04
450	Black Start Capability Settlement Debit	$216.97
452	Reactive Support and Voltage Control Settlement Debit	$1,752.11
454	Regulation Service Settlement Debit	$6,426.92
550	Must-Run Contract Settlement Debit	$18,052.00
650	Network Service Charge	$128,489.13
651	Line Connection Service Charge	$34,044.77
752	Debt Retirement Charge	$189,489.68
753	Rural Rate Settlement Charge	$27,069.95

Charge Type	Description	Amount
754	OPA Administration Charge	$10,584.35
900	GST Credit	-$3,571.28
950	GST Debit	$97,515.53
9990	IESO Administration Charge	$21,628.90
	Physical Market Invoice Prepayment	-$800,000.00
	Total	**$1,173,018.45**

c) Representative Generator Transmission Customer

The following table provides a sample invoice of typical wholesale charges for a representative generator transmission customer.

Charge Type	Description	Amount
100	Net Energy Market Settlement for Generators and Dispatchable Load	-$69,719,832.79
101	Net Energy Market Settlement for Non-Dispatchable Load	$3,429,097.08
105	Congestion Management Settlement Credit for Energy	-$364,151.15
106	Congestion Management Settlement Credit for 10 Minute Spinning Reserve	-$29,272.87
107	Congestion Management Settlement Credit for 10 Minute Non-spinning Reserve	-$24,441.23
108	Congestion Management Settlement Credit for 30 Minute Operating Reserve	-$10,103.47
112	Ontario Power Generation Rebate	-$110,673.84
119	Station Service Reimbursement Credit	-$72,949.21
133	Generation Cost Guarantee Payment	-$42,719.09
146	Global Adjustment Settlement Amount	$32,635.57
150	Net Energy Market Settlement Uplift	$13,391.30
155	Congestion Management Settlement Uplift	$12,209.03
169	Station Service Reimbursement Debit	$397.66
170	Local Market Power Rebate	-$225.22
183	Generation Cost Guarantee Recovery Debit	$2,483.56
186	Intertie Failure Charge Rebate	-$494.37
200	10 Minute Spinning Reserve Market Settlement Credit	-$35,594.55
202	10-Minute Non-Spinning Reserve Market Settlement Credit	-$28,942.81
204	30 Minute Operating Reserve Market Settlement Credit	-$27,082.14
250	10-Minute Spinning Market Reserve Hourly Uplift	$1,231.09
252	10-Minute Non-Spinning Market Reserve Hourly Uplift	$1,239.84
254	30-Minute Operating Reserve Market Hourly Uplift	$1,059.24
402	Reactive Support and Voltage Control Settlement Credit	-$33,667.23
404	Regulation Service Settlement Credit	-$44,612.34
450	Black Start Capability Settlement Debit	$77.01

Charge Type	**Description**	**Amount**
452	Reactive Support and Voltage Control Settlement Debit	$965.30
454	Regulation Service Settlement Debit	$2,154.21
550	Must-Run Contract Settlement Debit	$4,058.04
650	Network Service Charge	$12,866.70
651	Line Connection Service Charge	$3,461.24
652	Transformation Connection Service Charge	$10,400.60
653	Export Transmission Service Charge	$533.00
752	Debt Retirement Charge	$70,167.33
753	Rural Rate Settlement Charge	$10,023.90
754	OPA Administration Charge	$3,468.27
900	GST Credit	-$3,539,154.85
950	GST Debit	$141,692.66
9990	IESO Administration Charge	$8,222.04
	Total	**-$70,322,082.49**

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

Interrogatory

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

Ref: Exhibit A/Tab 14/Schedule 1/Page 3

Please explain why MCP base pay is projected to increase at 4% per year in 2009 and 2010, while represented groups are receiving less.

Response

The increases for represented staff are as per union contracts currently in place for the test years.

MCP base pay is determined and administered differently than base pay adjustments for unionized staff.

Part of Hydro One's staffing strategy is to retain skilled and competent employees. There is a demand for our management staff and Hydro One must reward and incent staff to stay with the Company.

Hydro One utilizes Hay Consulting to evaluate compensation relative to market. Compensation adjustments are made as deemed necessary to attract, motivate and retain staff. Conference Board data forecasts wages for non-unionized staff to increase by 4.1%. In August, utilities sector projections were in the range of 4.5%.

The Mercer Compensation Cost Benchmarking Study, Exhibit A, Tab 16, Schedule 2, Attachment 1, shows that MCP total compensation is 1% below median in comparison to the market.

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

Interrogatory

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

Interrogatory #2

Ref: Exhibit H1/Tab 5/Schedule 1

Preamble: In the settlement of the issue of the Export Transmission Service Tariff in EB-2006-0501, the parties were "supportive of the IESO undertaking a study of an appropriate ETS Tariff to be completed prior to the 2010 transmission rate setting process".

a) Please provide copies of the terms of reference and statement of deliverables for the IESO consultation to be delivered in June 2009.

b) The web address given for this study on the IESO site did not appear to display an initiative on the ETS tariff. Please provide the IESO reference number for this consultation.

c) Please provide any progress reports the IESO has given to Hydro One for this project.

Response

a) The IESO's Stakeholder Engagement Plan for the ETS tariff is available on the IESO's web site (http://www.ieso.ca/imoweb/consult/consult_se78.asp).

b) The reference number for the ETS tariff study consultation is SE-78.

c) Please see response to part a) above.

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

Interrogatory

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

Ref: Exhibit H1/Tab 5/Schedule 1

Preamble: As the export transmission tariff is a Hydro One tariff, it would seem incumbent on Hydro One to seek any required changes to the tariff via a Board rate setting process.

a) Does Hydro One anticipate applying for an interim adjustment to its rates, should the IESO recommend a change in the export tariff?

b) If the answer to a) is no, what process does Hydro One foresee to change the tariff?

Response

Please see response filed at Exhibit I, Tab 6, Schedule 24.

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

Interrogatory

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

Ref: Exhibit H1/Tab 5/Schedule 1

Please provide a calculation for the expected average revenue requirement associated with transmitting 1 MWhr on the Hydro One network (network only) for 2009 and 2010. In other words, if the network service charge was based on energy and not demand, what would be the average charge determinant in MWhr for 2009 and 2010?

Response

The necessary energy and Network revenue requirement for the other three Transmitters for 2009 and 2010 are not available to Hydro One to develop a Provincial Network Service Uniform Transmission Rate based on energy. The table below lists an equivalent Network rate for Hydro One Transmission only, if the charge determinant would be energy based.

Year	Hydro One Transmission Network Rate Pool	Network MWh	Equivalent [$/MWh]
2009	$ 688,005,115	140,580,965	4.89
2010	$ 762,129,647	135,870,089	5.61

Association of Major Power Consumers of Ontario (AMPCO) INTERROGATORY #5 List 1

Interrogatory

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

Ref: Exhibit A/Tab 15/Schedule 2/ Attachment 1/Section 4.2.2 (Page 20) (Benchmark Analysis)

In comparing metrics denominated by assets, did First Quartile Consulting control for differences in depreciation rates that might affect the results?

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

Response

Depreciation rates would not affect the First Quartile results because they used Gross Fixed Asset Value as their metric which does not include depreciation.

<u>Association of Major Power Consumers of Ontario (AMPCO) INTERROGATORY #6 List 1</u>

Interrogatory

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

<u>Interrogatory # 6</u>

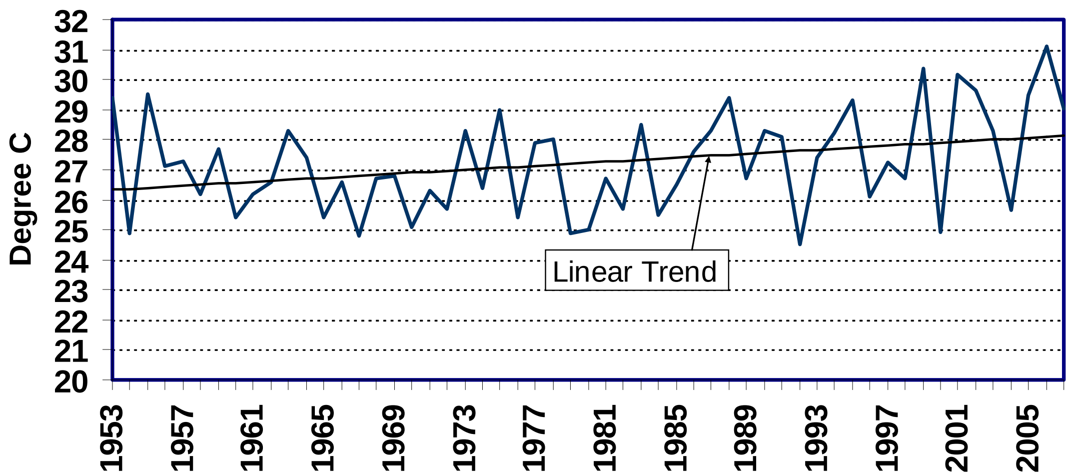
Ref: Exhibit A/Tab 14/Schedule 3/ Attachment A/ Figure 1 and Figure 2

Please provide augmented versions of these charts, with the addition of linear trend lines. In the alternate, please provide the source data.

Response

The requested information with linear trend lines for the 1953-2007 period is provided below.

Figure 1. Toronto Pearson International Airport: Maximum of Average Daily Temperature



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

<u>Interrogatory</u>

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

Ref: Exhibit A/Tab 14/Schedule 3/ Attachment B/ Table 2

Please provide actual (not weather corrected) average monthly peak demand for the years 2002-2007.

.

<u>Response</u>

The requested information is provided below using the same period as in Table 2 of Attachment B in Exhibit A, Tab 14, Schedule 3.

<u>Ontario Actual Avearge Peak-Load *</u>
(MW)

Year	Actual
2002	22,773
2003	22,281
2004	22,934
2005	23,043
2006	22,929
2007	22,204

* Average monthly peak over 18-month period starting in July of each year indicated above.

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

Interrogatory

Issue 5.3 Are the proposed Deferral/Variance Accounts appropriate?

Ref: Exhibit F1/Tab 1/Schedule 2/ Section 3.1

a) Has The OPA specifically requested Hydro One to undertake preliminary work on IPSP projects?

b) If so, has the OPA provided Hydro One with specific requirements for this development work, such as the quality of estimates and schedules, or the required extent of stakeholder consultations?

c) Has Hydro One requested that the OPA compensate Hydro One for IPSP project development work? If not, please explain the rationale for this decision.

d) Please comment on whether the project development work undertaken at the request of the OPA would be transferrable and useful to a third party, should Hydro One not be the transmitter selected to construct the projects.

Response

a) No. The OPA has not yet specifically requested that Hydro One undertake preliminary work on these projects.

b) Not applicable.

c) No. Hydro One anticipates that the project development work would be included in the project cost. Hydro One is proposing in this submission that these costs be captured in a deferral account as discussed in Exhibit F1, Tab 1, Schedule 2.

d) No. Since transmitters are commercial entities, it is Hydro One's view that development work is the responsibility of the party undertaking the work. In addition, the development work comprises consultations with affected stakeholders and involves commitments that third parties may not accept or be capable of fulfilling.

Association of Major Power Consumers of Ontario (AMPCO) INTERROGATORY #9 List 1

Interrogatory

Issue 7.1: Is the proposal to continue with the status quo charge determinants for Network and Connection service appropriate?

Has Hydro One conducted or commissioned any review of current or recent practices in other jurisdictions with respect to the use of ratchets in Network connection rate designs? If so, please provide the review or analysis.

Response

Hydro One has not conducted or commissioned any review on the use of ratchets in Network connection rate designs in other jurisdictions.

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

Interrogatory

Issue 7.1: Is the proposal to continue with the status quo charge determinants for Network and Connection service appropriate?

Ref: Exhibit H1/Tab 2/ Sch 1

Please provide an estimate of the 2009 and 2010 revenue impact on Hydro One under the following conditions, if the behaviour of loads is unchanged:

a) Reduction of the 85% ratchet to 50%.

b) Elimination of the 85% ratchet.

Response

If the Charge Determinants are changed to remove or alter the "ratchet", the resultant Uniform Transmitter Network Rate will also change so there would not be any expected impact on Hydro One's revenue for the proposed 2009 and 2010 periods.

However, assuming that the Uniform Transmission Network Rates are set and approved using the existing Charge Determinants methodology and then the "ratchet" is altered, the revenue impacts to Hydro One are provided in the table below. Hydro One can only present the results based on its own data since it does not have information on the extent to which the "ratchet" impacts the Network billing charge determinants for the other three Transmitters.

The Reference Scenario is Hydro One's specific Network charge determinant and revenue allocated to the Network pool. Under Scenarios A and B, new Network charge determinants were determined and the reduction in the new billing determinant compared to the Reference billing determinant is the basis for estimating the revenue impact.

Reference Scenario:		
2009 Hydro One Charge Determinants [MWs]		250,101
Hydro One Allocation		$688,005,115
Scenarios		
A: >50% NCP or CP		
2009 Hydro One Charge Determinants [MWs]		247,104
Charge Determinant change		-1.2%
Estimated Revenue Impact	(1.2% of $688 M)	$ (8,243,465)
B: CP [no ratchet]		
2009 Hydro One Charge Determinants [MWs]		246,487
Charge Determinant change		-1.4%
Estimated Revenue Impact	(1.4% of $688 M)	$ (9,940,492)

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

Interrogatory

Issue 7.1: Is the proposal to continue with the status quo charge determinants for Network and Connection service appropriate?

Ref: Exhibit H1/Tab 2/ Schedule 1

a) Please provide any analysis Hydro One has undertaken to estimate the affect that removal of the ratchet would have on customer behaviour.

a) Please identify the average (monthly) number of transmission connected customers, broken out by LDC and Direct, whose network connection charge is set by the 85% ratchet and not by coincident peak demand.

Response

a) No analysis concerning the removal of the "ratchet" has been undertaken by Hydro One.

b) Please see the response to interrogatory Exhibit I, Tab 6, Schedule 67, part b.

Consumers Council of Canada (CCC) INTERROGATORY #1 List 1

Interrogatory

Issue 1.1

1. A/T16/S2/p. 3\

The compensation cost study undertaken by Mercer concluded that "on an overall weighted average basis for the positions reviewed HON is approximately 17% above the market median" Please describe all of the initiatives HON is doing to reduce the gap between its compensation levels and the levels of its comparators. What plans does HON have in 2009 and 2010 to undertake further benchmarking analysis?

Response

It is important to put into the appropriate context the conclusion that Hydro One is approximately 17% above market median. For MCP and Society total compensation, the Mercer benchmarking study results show Hydro One's total compensation for these two groups are essentially at median. The driver behind the 17% average figure is PWU total compensation.

As stated in the prefiled evidence, PWU compensation is a product of legacy collective bargaining and competition for highly sought after skills.

Hydro One has made both cost and productivity improvements through collective bargaining. Exhibit C1, Tab 3, Schedule 2, pp 7-9 highlight significant changes achieved through both PWU and Society bargaining. As also outlined in evidence in Exhibit A, Tab 16, Schedule 1, Hydro One has successfully undertaken numerous cost efficiency initiatives in the past and has laid out initiatives it is and will undertake to continue to improve cost efficiency in the future. Part and parcel of this is the use of benchmarking to help identify areas requiring improvement.

Finally, as noted by Mercer/ Oliver Wyman in the Productivity Benchmarking portion of the "Compensation Cost Benchmarking Study ":

> "Hydro One's productivity for Transmission and Distribution function and Customer Service functions are each measured along four indicators. All indicators measured ranked better than median (i.e. more productive) except one which is slightly below median (i.e. less productive). ***Examining the mix of [productivity] indicators leads to the conclusion that Hydro One requires less workforce compensation to generate various units of output.***"

The positive Hydro One productivity results provide further support for Hydro One's position that its continued productivity accomplishments offset its relative compensation levels.

Consumers Council of Canada (CCC) INTERROGATORY #2 List 1

Interrogatory

Issue 2.1

2. A/T14/S3/Attachment B

The evidence states that HON's joint study with the IESO to compare monthly peak forecast of the two organizations revealed that the IESO, monthly peak forecast is about 1000 MW higher than the HON forecast. What are the implications of this difference for HON's 2009 load forecast?

Response

The joint study explains how the different approaches used by Hydro One and the IESO results in a 1000 MW difference in the monthly peak forecast. The IESO's methodology is appropriate for reliability planning in the province, while Hydro One's methodology is appropriate for the purpose of determining transmission rates. Hydro One's 2009 and 2010 load forecast is appropriate and there is no need to make any adjustments.

Consumers Council of Canada (CCC) INTERROGATORY #3 List 1

Interrogatory

Issue 2.1

3. A/T14/S3/Attachment C

The evidence states that two special studies were undertaken by HON to measure the load impact of CDM programs in Ontario. Please provide copies of those studies.

Response

As documented in the Attachment C Report of Exhibit A, Tab 14, Schedule 3, Hydro One undertook 2 studies (i.e., 2 types of analyses) to measure the load impact of CDM programs in Ontario. No separate reports were prepared.

One study, as summarized in Section 3.2, is the conservation actions undertaken by customers. All the detailed analyses were provided in Appendices E, F, G and H in the Attachment C Report.

Another study is an econometric analysis using data for 2004 and 2007 to measure the CDM impact between 2004 and 2007. Two econometric models were used and the results were summarized in Section 3.1.

The following provides additional details of the regression results of the 2 econometric models used.

Regression results of the in-house econometric model

R-Square=0.9942 Adj R-Sq=0.9942

Variable	Definition	DF	Parameter Estimate	Standard Error	t value
hdd	heating degree days	1	63.16016	3.23892	19.5
cdd	heating degree days	1	176.7747	17.04241	10.37
hddhr1	hdd*hour1 dummy variable (0/1)	1	-42.18188	4.41468	-9.55
hddhr2	hdd*hour2 dummy variable (0/1)	1	-62.53057	4.41468	-14.16
hddhr3	hdd*hour3 dummy variable (0/1)	1	-74.50849	4.41468	-16.88
hddhr4	hdd*hour4 dummy variable (0/1)	1	-77.74279	4.41468	-17.61
hddhr5	hdd*hour5 dummy variable (0/1)	1	-68.34579	4.41468	-15.48
hddhr6	hdd*hour6 dummy variable (0/1)	1	-37.76066	4.41468	-8.55
hddhr7	hdd*hou7 dummy variable (0/1)	1	22.62145	4.41468	5.12
hddhr8	hdd*hour8 dummy variable (0/1)	1	88.69253	4.41468	20.09
hddhr9	hdd*hour9 dummy variable (0/1)	1	116.99384	4.41468	26.5

Variable	Definition	DF	Parameter Estimate	Standard Error	t value
hddhr10	hdd*hour10 dummy variable (0/1)	1	129.47277	4.41468	29.33
hddhr11	hdd*hour11 dummy variable (0/1)	1	136.06138	4.41468	30.82
hddhr12	hdd*hour12 dummy variable (0/1)	1	134.73788	4.41468	30.52
hddhr13	hdd*hour13 dummy variable (0/1)	1	126.49172	4.41468	28.65
hddhr14	hdd*hour14 dummy variable (0/1)	1	118.54836	4.41468	26.85
hddhr15	hdd*hour15 dummy variable (0/1)	1	111.46461	4.41468	25.25
hddhr16	hdd*hour16 dummy variable (0/1)	1	115.9185	4.41468	26.26
hddhr17	hdd*hour17 dummy variable (0/1)	1	141.89146	4.41468	32.14
hddhr18	hdd*hour18 dummy variable (0/1)	1	181.71947	4.41468	41.16
hddhr19	hdd*hour19 dummy variable (0/1)	1	192.15862	4.41468	43.53
hddhr20	hdd*hour20 dummy variable (0/1)	1	182.67061	4.41468	41.38
hddhr21	hdd*hour21 dummy variable (0/1)	1	159.30815	4.41468	36.09
hddhr22	hdd*hour22 dummy variable (0/1)	1	118.43405	4.41468	26.83
hddhr23	hdd*hour23 dummy variable (0/1)	1	60.12362	4.41468	13.62
cddhr1	cdd*hour1 dummy variable (0/1)	1	-158.38165	23.77786	-6.66
cddhr2	cdd*hour2 dummy variable (0/1)	1	-241.50693	23.77786	-10.16
cddhr3	cdd*hour3 dummy variable (0/1)	1	-307.85005	23.77786	-12.95
cddhr4	cdd*hour4 dummy variable (0/1)	1	-329.77392	23.77786	-13.87
cddhr5	cdd*hour5 dummy variable (0/1)	1	-286.05478	23.77786	-12.03
cddhr6	cdd*hour6 dummy variable (0/1)	1	-166.63033	23.77786	-7.01
cddhr7	cdd*hou7 dummy variable (0/1)	1	70.36474	23.77786	2.96
cddhr8	cdd*hour8 dummy variable (0/1)	1	310.6635	23.77786	13.07
cddhr9	cdd*hour9 dummy variable (0/1)	1	492.55333	23.77786	20.71
cddhr10	cdd*hour10 dummy variable (0/1)	1	645.05868	23.77786	27.13
cddhr11	cdd*hour11 dummy variable (0/1)	1	753.22303	23.77786	31.68
cddhr12	cdd*hour12 dummy variable (0/1)	1	805.6379	23.77786	33.88
cddhr13	cdd*hour13 i dummy variable (0/1)	1	855.22336	23.77786	35.97
cddhr14	cdd*hour14 dummy variable (0/1)	1	868.48142	23.77786	36.52
cddhr15	cdd*hour15 dummy variable (0/1)	1	878.30849	23.77786	36.94
cddhr16	cdd*hour16 dummy variable (0/1)	1	900.16765	23.77786	37.86
cddhr17	cdd*hour17 dummy variable (0/1)	1	889.62316	23.77786	37.41
cddhr18	cdd*hour18 dummy variable (0/1)	1	811.96326	23.77786	34.15
cddhr19	cdd*hour19 dummy variable (0/1)	1	718.6474	23.77786	30.22
cddhr20	cdd*hour20 dummy variable (0/1)	1	670.87304	23.77786	28.21
cddhr21	cdd*hour21 dummy variable (0/1)	1	654.93754	23.77786	27.54
cddhr22	cdd*hour22 dummy variable (0/1)	1	478.69818	23.77786	20.13
cddhr23	cdd*hour23 dummy variable (0/1)	1	211.94373	23.77786	8.91

<u>Regression results of the MetrixND Model</u>

A separate mode is used for each hour. The summary statistics are presented below.

R-Square=0.84 Adj R-Sq=0.84

Model	R-Sq	Adj R-Sq	F Stat	F-Stat Prob
Model for hour1	0.75	0.75	350.80	0.00
Model for hour2	0.58	0.57	134.12	0.00
Model for hour 3	0.62	0.62	161.51	0.00
Model for hour 4	0.62	0.61	157.79	0.00
Model for hour 5	0.61	0.61	156.11	0.00
Model for hour 6	0.64	0.63	171.88	0.00
Model for hour 7	0.66	0.66	193.42	0.00
Model for hour 8	0.72	0.72	257.26	0.00
Model for hour 9	0.73	0.73	270.68	0.00
Model for hour 10	0.81	0.81	423.46	0.00
Model for hour 11	0.83	0.83	475.36	0.00
Model for hour 12	0.85	0.85	566.81	0.00
Model for hour 13	0.86	0.86	617.80	0.00
Model for hour 14	0.87	0.87	640.13	0.00
Model for hour 15	0.88	0.87	691.57	0.00
Model for hour 16	0.88	0.88	701.84	0.00
Model for hour 17	0.82	0.82	447.17	0.00
Model for hour 18	0.55	0.55	121.61	0.00
Model for hour 19	0.71	0.70	238.45	0.00
Model for hour 20	0.83	0.83	483.07	0.00
Model for hour 21	0.85	0.85	572.74	0.00
Model for hour 22	0.83	0.83	488.85	0.00
Model for hour 23	0.82	0.81	438.30	0.00
Model for hour 24	0.81	0.81	428.39	0.00

Both the in-house econometric and MetrixND models generate hourly load profiles. The difference between the load profiles in 2004 and 2007 included the impact of CDM and economic growth. The weather-corrected peak load in 2007 would have been lower if there was no economic growth between 2004 and 2007. Since the Ontario economy grew during this period, the assumed economic growth should be added back in order to determine the net CDM impact. Using the GDP elasticity of peak load of 0.35 for the 2004 and 2007 period, the peak contribution due to economic growth is estimated to be about 621 MW. The following table compares the CDM impact on the summer peak for the in-house econometric and MetrixND models. The load profile results from the 2 models show that Ontario had achieved a summer peak demand reduction in the range of 1,450 MW to 1,650 MW.

	Econometric Analysis			MetrixND Analysis		
	Jun	July	Aug	Jun	July	Aug
Difference between peak in 2004 and 2007 in MW(1)	141	860	692	239	1,046	897
Assumed economic impact in MW(2)	621	621	621	621	621	621
CDM Impact (1)+(2)	762	1481	1313	860	1667	1518

Consumers Council of Canada (CCC) INTERROGATORY #4 List 1

Interrogatory

Issue 2.1

A/T14/S7/p. 3

The evidence states that, "the rapid increase in distributed wind, solar and small hydroelectric generation installations have resulted in the need to complete a large number of connection designs. Moreover, changing from a small number of very large generation facilities to a much larger number of smaller generation facilities requires significant changes to the transmission system to ensure its safe operation, protection and control." Please provide the impacts on the 2009 and 2010 capital expenditure programs related to this rapid increase in distributed generation. Please provide a detailed explanation as to how the costs associated with this trend have been incorporated into the budgets for each year.

Response

The submitted 2009 and 2010 capital expenditure programs have limited expenditures related directly to the rapid increase in new generation. These are described in Exhibit D1-3-3, Section 3.4 and are as follows:

Project	**2009**	**2010**
Lower Mattagami Extensions	$6.9M	$16.4M
Other capital projects related to contracted or substantially advanced generation projects including: • Greenfield South • TCE Halton Hills • Kingsbridge II • Northland Thorold • Beck #1 G7 Conversion	$5.0M	$6.4M
Provision for expected expenditures related to new generators including those to be developed under the RES III RFP, the CHP II and III RFP's, and other OPA procurements	$0.0M	$9.5M

The Lower Mattagami Extensions project is described in more detail in Exhibit D2-2-3, reference # D32.

The submission does include major capital expenditures for projects related to the incorporation of new supply sources. These are described in Exhibit D1-3-3, Section 3.1 regarding Inter Area Network Transfer Capability projects. These projects provide additional transfer capability than can benefit both load and generation, with the following projects aimed primarily at adding capacity for new Ontario generation remote from load:

- New 500 kV Bruce to Milton double circuit transmission line
- Northeast transmission reinforcement: installation of Static Var Compensators at Porcupine TS and Kirkland Lake TS
- Installation of Series Capacitors at Nobel SS
- Installation of Static Var Compensators at Mississagi TS
- Installation shunt capacitor banks at Algoma TS, Mississagi TS and Porcupine TS
- Installation of SVCs and shunts in southwestern Ontario

The planned level of expenditures is consistent with Hydro One's understanding of the plans in place at the time the submission was developed and the cost allocation rules in the current Transmission System Code. These plans may change due to the Minister's direction to the OPA to review the IPSP including, among other things:

- The amount and diversity of renewable energy sources in the supply mix.
- The improvement of transmission capacity in the orange zones in northern Ontario and other parts of the province that is limiting the development of new renewable energy supply.
- The potential of converting existing coal-fired assets to biomass.
- The availability of distributed generation.
- The potential for pumped storage to contribute to the energy supply during peak times.

Consumers Council of Canada (CCC) INTERROGATORY #5 List 1

Interrogatory

Issue 2.2

E1/T1/S2/p. 2

External Revenues are forecast to decline significantly in 2009 and 2010 relative to historic levels. HON's evidence is that this is due to one-time events during previous years. Please provide more detailed budgets for External Revenue for the years 2006 to 2010 to support the 2009 and 2010 budget levels.

Response

As noted in Exhibit E1, Tab 1, Schedule 2, Hydro One Transmission's strategy is to focus on core work, while continuing to be responsive to external customer work requests where Hydro One Transmission has available resources and/or assets to accommodate the request. As such, it is expected that revenues from external work will trend downwards over time

The primary reasons for temporary increases in external revenue are summarized below:

- The temporary increase in Engineering and Construction activities in 2007 was directly related to work associated with revenue meter upgrades at various sites. The completion of revenue meter upgrades in 2008, at sites such as Bruce, Carlton TS, Leslie TS, Fairchild TS, Beach TS, Lake TS and Mohawk TS, contributed to the temporary increase in Engineering and Construction activities for 2008 as well.

- The 2006 to 2008 revenue levels for secondary land use are unusually elevated due to one-time events, such as granting of easement rights to Enbridge and the City of Toronto, and one-time sales of land, resulting in one-off lump sum payments during this timeframe.

Consumers Council of Canada (CCC) INTERROGATORY #6 List 1

Interrogatory

Issue 3.1

6. A/T17/S1/pp. 1-7

HON undertook extensive stakeholder consultation processes leading up to the 2009/2010 filing. Please provide the costs of those sessions and explain how the costs are being recovered. Please provide specific amounts for each of the sessions set out in Table 1 at page 7.

Response

Hydro One has found that the involvement of stakeholders is critical to developing a rate submission that reflects the broad interests and concerns of Hydro One transmission customer and stakeholder constituencies. Moreover, the Ontario Energy Board directed Hydro One to seek stakeholder involvement in the areas of transmission asset assessment and sustainment and compensation cost and productivity benchmarking for its 2009/2010 Transmission Rate Application.

The stakeholder consultation program was reviewed with a small cross-section of stakeholders on February 28, 2008, presented to Hydro One's Customer Advisory Board, and finally reviewed with all stakeholders at the June 4, 2008 session to ensure support for the approach.

The approximate cost for each stakeholder session on Table 1 at Page 7 is outlined below. These costs will be recovered in rates charged to all Hydro One customers as approved in the 2009/2010 rate filing.

Tx 2009/2010 Stakeholder Consultation Costs					
Date	**Consultant Cost (facilitation, notes, other)**	**Facility and associated costs**	**Stakeholder Participant Funding**	**# of Stakeholder Claims Submitted**	**Approx. Session Cost**
15-Oct-07	$3,100	$2,600			$11,050
17-Oct-07	$6,200	$4,400	$10,700	6	$15,950
17-Dec-07	$10,270	$4,700	$2,600	2	$17,570
17-Mar-08	$7,700	$2,000	$2,700	3	$12,400
4-Jun-08	$15,800	$2,300	$4,100	3	$22,200
Sept 3 & 4, 2008	$14,000	$6,700	$7,500	3	$28,300

Consumers Council of Canada (CCC) INTERROGATORY #7 List 1

Interrogatory

Issue 3.1

7. C1/T2/S1/p. 2

Please provide a table in the same format as Table 1 – Summary of Transmission OM&A Budget which includes Board approved numbers for 2005 and 2006.

Response

There are no Board approved amounts for 2005 and 2006. Hydro One Transmission did not have an application before the Board during this time period.

Consumers Council of Canada (CCC) INTERROGATORY #8 List 1

Interrogatory

Issue 3.1

C1/T2/S3/p. 2

Please provide a schedule which sets out a detailed "Research and Development" budget for 2009 and 2010. Please provide a list of all proposed projects. How does HON prioritize the projects it intends to pursue? Are these projects subject to a cost-benefit analysis? If so, please provide that analysis for each project. If not, how does HON decide whether to pursue the projects?

Response

Please refer to Interrogatory Exhibit I, Tab 4, Schedule 14.

Consumers Council of Canada (CCC) INTERROGATORY #9 List 1

Interrogatory

Issue 3.1

C1/T2/S5p. 3

Please provide a schedule in the same format as Table 1 – Allocated Transmission Shared Services and Other OM&A Costs which includes Board approved numbers 2005-2008.

Response

The following schedule from Exhibit C1, Tab 2, Schedule 5, page 3 – Table 1 has been modified to reflect the 2007 and 2008 Board approved amounts. There are no Board approved amounts for 2005 and 2006.

Allocated Transmission Shared Services and Other OM&A Cost ($ Millions)

($ Millions)	**Historic Actuals**			**Bridge**	**Historic Filed** Board Approved EB-2006-0501		**Test**	
	2005	**2006**	**2007**	**2008**	**2007**	**2008**	**2009**	**2010**
Common Corporate Functions & Services	40.5	38.0	39.7	45.8	40.8	40.9	47.5	47.9
Customer Care	4.4	3.1	1.2	1.6	1.6	1.6	1.5	1.5
Asset Management	36.3	53.8	55.7	72.1	58.2	57.3	76.7	81.2
Information Technology	38.3	45.6	43.1	47.7	45.9	43.9	49.9	50.3
Cornerstone	-	2.2	2.7	3.1	-	-	(3.4)	(8.9)
Cost of Sales	15.7	16.6	14.5	12.4	10.5	9.9	4.1	3.7
Other OM&A	(75.2)	(83.0)	(70.5)	(106.3)	(89.6)	(96.5)	(104.6)	(109.3)
Total	**59.9**	**76.3**	**86.4**	**76.4**	**67.4**	**57.1**	**71.6**	**66.4**

Consumers Council of Canada (CCC) INTERROGATORY #10 List 1

Interrogatory

Issue 3.1

C1/T2/S6/p. 16

With respect to HON's Corporate Communications budget please provide the following: a detailed budget for each year 2007-2010. Please provide specific budgets for CDM and smart meter activities for 2008-2010 and explain how they relate to transmission operations. Please provide all assumptions used to develop the budgets.

Response

Hydro One's corporate communication budget is comprised both labour and non-labour costs. Labour costs include all salaries and benefits payable to Hydro One staff. Non-labour expenses are comprised of the activities referenced in C1/T2/S6/p. 16. Budgets are developed using approved assumptions which include labour escalation and benefit cost rates.

Although Corporate Communication staff participate in CDM and smart metering communication requirements, the cost of these activities are not included in the Corporate Communication budgets for any of the years referenced.

Consumers Council of Canada (CCC) INTERROGATORY #11 List 1

Interrogatory

Issue 3.1

C1/T2/S6/p. 20

Please indicate how all regulatory costs are accounted for (internal and external). Please provide a detailed budget for HON's regulatory costs for the years 2007-2010. Please provide 2008 Board approved amounts. Please include any internal costs, external costs (legal and consulting) and costs associated with each rate proceeding.

Response

Hydro One Network's regulatory costs are comprised of Regulatory Affairs and OEB Costs as shown in Table 8 of Exhibit C1, Tab 2, Schedule 6.

The Regulatory Affairs costs can be further broken down into internal labour and non-labour costs. Internal labour costs consist of all regular staff payroll costs. Non-labour costs include the cost of consultants and contract services net of recoveries, other OEB costs and miscellaneous internal costs.

Regulatory Affairs are accounted for in aggregate and allocated to Transmission and Distribution using the Rudden cost allocation model.

The 2008 OEB approved Transmission costs for the Regulatory Affairs function is $10.2M (Reference: EB-2006-0501 Exhibit C1, tab 2, Schedule 5, Table 10, page 32

<u>Consumers Council of Canada (CCC) INTERROGATORY #12 List 1</u>

<u>Interrogatory</u>

Issue 3.1

C1/T2/S6/p. 20

Please explain how the regulatory affairs budget is allocated between Distribution and Transmission.

<u>Response</u>

The Regulatory Affairs budget is allocated between Distribution and Transmission following the cost allocation methodology as described in Exhibit C1, Tab 5, Schedule 1. The methodology is based on appropriate cost drivers associated with Regulatory Affairs activities. A review of implementation of common corporate cost methodology was completed in 2008 and is included as Attachment 1 to Exhibit C1, Tab 5, Schedule 1.

Consumers Council of Canada (CCC) INTERROGATORY #13 List 1

Interrogatory

Issue 3.1

C1/T2/S6/p. 28

Please describe how the capitalized overhead rate for Transmission was determined. Has the rate been changed since the 2007/2008 rate application? If so, on what basis has it changed?

Response

The overhead capitalization rate was determined based upon the Rudden Overhead Rate Capitalization methodology found in Exhibit C1, Tab 5, Schedule 2, Attachment 1.

The common costs to be allocated (numerator) have changed and the work programs (denominator) have changed resulting in revised rates as common costs divided by work programs result in rates.

Consumers Council of Canada (CCC) INTERROGATORY #14 List 1

Interrogatory

Issue 3.1

C1/T2/S8/p. 5

The Strategy and Business Development budget has increased significantly from the 2007 level. Please provide a detailed budget for this group and provide a variance analysis which explains the increase.

Response

Please see the response to SEC interrogatory at Exhibit I, Tab 4, Schedule 17.

Consumers Council of Canada (CCC) INTERROGATORY #15 List 1

Interrogatory

Issue 3.1

C1/T2/S6/p. 20

Please explain how the Strategy and Business Development budget is allocated between Transmission and Distribution. Please indicate whether or not the costs associated with the development of distribution CDM programs and the initiation and management of OPA funded programs are allocated to distribution only.

Response

Note: The above reference should be C1/T2/S8/pgs. 5-7

Strategy and Business Development consists of the strategy, conservation, business development and asset management administration costs. Funding for property insurance and boiler and machinery insurance is also contained within the budget.

The Strategy and Conservation function is responsible for a number of activities (such as developing the long term corporate vision, for example). Included in its purview is leading and supporting the development and integration of strategies that respond to corporate direction, and to changes in the industry environment or government policy – such as the Conservation and Demand Management (CDM) initiative. As Strategy and Business Development is a shared service within Asset Management, and its activities support both Transmission and Distribution businesses, OM&A costs are allocated using the R.J. Rudden Associates methodology approved by the OEB in our previous Transmission filing (see EB-2006-0501 Exhibit C1, Tab 5, Schedule 1 for further details).

Consumers Council of Canada (CCC) INTERROGATORY #16 List 1

Interrogatory

Issue 3.1

C1/T2/S6/pp. 20-21

Please indicate if the costs associated with any of the "Business Development" activities are allocated to Transmission. If they are, please explain the rationale.

Response

Note: The above reference should be C1/T2/S8/pgs. 5-7

The Business Development function's responsibilities include smart meters, but also such functions as supporting opportunities to optimize leveraging of Hydro One Networks' assets through secondary land use, utility rationalization, and utility boundary adjustments. As Business Development is a shared service within Asset Management, and its activities support both Transmission and Distribution businesses, OM&A costs are allocated using the R.J. Rudden Associates methodology approved by the OEB in our previous Transmission filing (see EB-2006-0501 Exhibit C1, Tab 5, Schedule 1 for further details).

Consumers Council of Canada (CCC) INTERROGATORY #17 List 1

Interrogatory

Issue 3.1

C1/T2/S9/p. 1

Please provide a schedule in the same format as Table 1 – Information Technology Summary of OM&A Expenditures that provides Board approved numbers for the years 2007 and 2008.

Response

	Historic Actual			Bridge	Networks Filed (EB-2006-0501)		TX Allocation Approved (EB-2006-0501)		Test		TX Allocation	
	2005	**2005**	**2007**	**2008**	**2007**	**2008**	**2007**	**2008**	**2009**	**2010**	**2009**	**2010**
Sustainment	57.6	60.2	63.9	71.5	59.2	57.7	24.7	23.7	79.7	81.3	32.3	33.0
Development	7.0	8.9	6.0	6.2	14.9	13.2	9.0	7.9	6.0	5.6	2.6	2.5
Business Telecom	15.7	18.6	17.2	17.2	17.0	17.1	8.3	8.3	20.4	20.3	9.6	9.6
IT Management & Project Control	5.6	5.0	6.7	9.1	7.5	7.7	3.9	4.0	11.6	11.4	5.4	5.3
Total Cost	**85.8**	**92.7**	**93.8**	**104.0**	**98.6**	**95.6**	**45.9**	**43.9**	**117.7**	**118.6**	**49.9**	**50.3**

Consumers Council of Canada (CCC) INTERROGATORY #18 List 1

Interrogatory

Issue 3.1

C1/T2/S9/p. 20

Business Telecom OM&A expenditures are rising significantly from the 2007 levels. Please provide a detailed budget for this group and explain why the costs are increasing. Please provide the Board approved amounts for 2007 and 2008.

Response

	Historic Actual			Bridge	Networks Filed (EB-2006-0501)		TX Allocation Approved (EB-2006-0501)		Test		TX Allocation	
	2005	**2006**	**2007**	**2008**	**2007**	**2008**	**2007**	**2008**	**2007**	**2008**	**2009**	**2010**
Operations and Carrier Management	3.0	3.2	4.2	4.4	3.2	3.7	1.5	1.8	4.8	5.0	2.3	2.3
Field Services	3.4	4.0	3.8	3.6	5.1	4.7	2.5	2.3	5.0	4.5	2.4	2.1
Voice Services	3.7	5.4	4.1	3.8	3.8	3.9	1.9	1.9	4.9	4.9	2.3	2.3
Data Networks	5.6	6.0	5.1	5.4	4.8	4.8	2.4	2.4	5.7	5.9	2.7	2.8
Total	**15.7**	**18.6**	**17.2**	**17.2**	**17.0**	**17.1**	**8.3**	**8.3**	**20.4**	**20.3**	**9.6**	**9.6**

Total costs between 2007 and 2008 remained constant. Total costs have increased between 2008 and 2009. A description of these changes is provided in the prefiled written evidence in Exhibit C1, Tab 2, Schedule 9, pages 14-19, and in School Energy Coalition (SEC) Interrogatory response filed in Exhibit I, Tab 4, Schedule 19.

Consumers Council of Canada (CCC) INTERROGATORY #19 List 1

Interrogatory

Issue 3.1

C2/T2/S1/pp. 1-2

Please provide a schedule in the same format as "Comparison of OM&A Expense by Major Category" which includes Board approved amounts for 2005-2008.

Response

There are no "Board Approved" amounts for 2005 and 2006. The last Board approved expenditures for Transmission were in 2000 as part of proceeding RP-1999-0044. The revenue requirement was subsequently approved for 2007 and 2008 as part of proceeding EB-2006-0501.

The "Board Approved" values for 2007 and 2008 are included the table below.

	Historic			Board Approved	Bridge	Board Approved	Test	Test
	2005	**2006**	**2007**	**2007**	**2008**	**2008**	**2009**	**2010**
Transmission OM&A ($ millions)								
Sustaining								
Transmission Stations								
Land Assessment and Remediation	4.6	3.1	3.9	3.9	3.7	3.7	1.6	1.2
Environment Management	3.5	5.9	8.4	8.6	6.7	8.6	9.1	9.9
Power Equipment	42.2	52.9	69.4	56.5	60.0	57.0	74.7	82.0
Protection, Control, Monitoring, Metering and Telecommunications	34.2	36.7	37.7	37.6	37.9	37.1	39.5	41.6
Ancillary System Maintenance	9.9	9.6	9.6	14.4	13.9	15.0	18.2	21.0
Site Infrastructure Maintenance	23.7	18.6	21.0	21.7	24.2	22.4	24.7	25.5
Total Transmission Stations OM&A	118.1	126.9	150.0	142.7	146.3	143.8	167.7	181.3
Transmission Lines								
Rights of Way	22.0	21.7	27.0	20.5	21.2	21.0	23.3	24.6
Overhead Lines	16.5	17.9	16.5	24.2	19.6	22.9	22.1	20.9
Underground Cables	3.0	5.4	3.5	3.7	3.4	3.9	3.3	3.3

	Historic 2005	Historic 2006	Historic 2007	Board Approved 2007	Bridge 2008	Board Approved 2008	Test 2009	Test 2010
Total Transmission Lines OM&A	41.5	45.0	47.0	48.4	44.2	47.8	48.7	48.8
Engineering & Environmental Support	6.7	7.2	8.9	9.0	7.4	9.3	10.2	10.2
Total "Sustaining"	166.3	179.0	205.9	200.1	197.9	200.9	226.5	240.1
Development								
Technical Standards and Technology	6.7	8.1	8.4	8.0	10.0	8.1	13.9	16.3
Total Development OM&A	6.7	8.1	8.4	8.0	10.0	8.1	13.9	16.3
Operations								
Operations Contracts	12.1	14.6	18.3	13.5	16.4	13.8	17.1	17.5
Environmental, Health and Safety	0.7	0.8	2.9	1.9	2.0	1.4	2.1	2.1
Operators	25.5	27.4	28.4	30.4	31.8	31.0	33.1	34.0
Total "Operations"	38.3	42.9	49.7	45.8	50.1	46.2	52.3	53.7
Shared Services and Other Costs								
Customer Care	4.4	3.1	1.2	1.6	1.6	1.6	1.5	1.5
Asset Management	36.3	53.8	55.7	58.2	72.1	57.3	76.7	81.2
Common Corporate Functions & Services	40.5	38.0	39.7	40.8	45.8	40.9	47.5	47.9
Information Technology	38.3	45.6	43.1	45.9	47.7	43.9	49.9	50.3
Cornerstone	-	2.2	2.7	0.0	3.1	0.0	(3.4)	(8.9)
Cost of Sales	15.7	16.6	14.5	10.5	12.4	9.9	4.1	3.7
Other	(75.2)	(83.0)	(70.5)	(89.6)	(106.3)	(96.5)	(104.6)	(109.3)
Total Shared Services & Other Costs	59.9	76.3	86.4	67.4	76.4	57.1	71.6	66.4
Property Taxes & Rights Payments	70.5	68.6	62.5	72.8	68.4	75.1	70.9	73.1
Total Transmission OM&A	341.8	374.9	412.9	394.1	402.7	387.5	435.2	449.7

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Consumers Council of Canada (CCC) DUPLICATES INTERROGATORIES, List 1

The following Consumers Council of Canada (CCC) interrogatories are duplicate questions.

Question	Is a duplicate of questions	Response in
20	6	Exhibit I, Tab 11, Schedule 6
21	7	Exhibit I, Tab 11, Schedule 7
22	8	Exhibit I, Tab 11, Schedule 8
23	9	Exhibit I, Tab 11, Schedule 9
24	10	Exhibit I, Tab 11, Schedule 10
25	11	Exhibit I, Tab 11, Schedule 11
26	12	Exhibit I, Tab 11, Schedule 12
27	14	Exhibit I, Tab 11, Schedule 14
28	15	Exhibit I, Tab 11, Schedule 15
29	16	Exhibit I, Tab 11, Schedule 16
30	17	Exhibit I, Tab 11, Schedule 17
31	18	Exhibit I, Tab 11, Schedule 18
32	19	Exhibit I, Tab 11, Schedule 19
34	13	Exhibit I, Tab 11, Schedule 13

NOTE: Exhibit I, Tab 11, Schedule 21 to 32 and Schedule 34 will not be printed.

Consumers Council of Canada (CCC) INTERROGATORY #33 List 1

Interrogatory

Issue 3.2

A/T9/S2

With respect to HON's Affiliate Services please explain to what extent any of the services provided, and related service agreements, have changed since the 2007-2008 rates proceeding.

Response

There have not been any changes for the services provided included in the existing agreements. There is one new agreement between Hydro One Remote Communities Inc. and Hydro One Networks Inc. for Joint Use Services. Please see Exhibit A, Tab 9, Schedule 2, Appendix F for the agreement which relates to the implementation, support, and training on joint use agreements and databases.

Consumers Council of Canada (CCC) INTERROGATORY #35 List 1

Interrogatory

Issue 4.1

A/T14/S 7/p. 8

The evidence states that due to the increased number and size of many "Greenfield" projects required to expand and develop the transmission system a greater use of turnkey contracts is being made ($300 m in 2009). Please describe the process that HON uses to decide whether or not to use turnkey contracts. How does HON assess the cost/benefit of doing so relative to the use of internal resources? What processes does HON use to acquire turnkey contracts? If the policies are set out in writing please provide those policies.

Response

Bids are sought for Turnkey contracts when all of the following apply:

a) The work does not involve work on live equipment
b) The work can be reasonably separated from other Hydro One operating systems
c) There are insufficient resources in-house to complete the work.
d) External contractors exist with the required skills and resources to complete the work to Hydro One standards and in the time frame required.
e) The cost of doing the work using an external turnkey contract is not significantly higher than doing it with internal resources.

Hydro One prepares its own internal estimates for all planned work and these estimates are compared to bid prices received by external contractors where such bids meet Hydro One standards and time schedule.

Turnkey contracts are publically advertised and contractors wishing to bid on them are invited to do so. Our purchasing organization establishes a running list of prequalified contracting companies.

Procurement Procedure, attached as Attachment 1 to this interrogatory, provides details of how to solicit, evaluate and award external contracts.

Filed: December 23, 2008
EB-2008-0272
Exhibit I-11-35
Attachment 1

HODS

Document Number: **SP 0826 R0**

Document Name: **Procurement Procedure**

Issue Date: **August 2008**

When in printed form, this document is uncontrolled.
It is the user's responsibility to verify that this copy matches the document on the Hods website.

The requirements of this document are mandatory.

Purpose

The procedure provides Hydro One employees with direction on and understanding of the various aspects of the procurement cycle associated with soliciting, evaluating and awarding requirements to external vendors.

Revision

Information contained in the policy, approved in October 2007, is now contained in this document.

Contents

1.0 Summary

This is a high-level procedure. Inergi Supply Management Services/Hydro One Supply Chain Services trained purchasing staff ("Purchasing Individuals") possess the expertise to guide Requisitioners through the process of securing materials and services and have access to specific guidelines (Buying Guide Manual/SMS Operations Manual), templates and resources to enable them to conduct the competitive process. Purchasing Individuals will ensure the Corporation's purchasing power is leveraged to maximize value.

2.0 Governing Principles

The Procurement Policy is designed to add value to Hydro One's Procurement and supply processes. This Procurement Procedure and the Corporate Procedure for Retention of Consultants support the Procurement Policy and Corporate Policy on Consultants and have been developed to ensure the policy and principles are implemented in a consistent, professional and transparent manner. They are intended to provide Hydro One employees with direction on and understanding of the various aspects of the procurement cycle associated with soliciting, evaluating and awarding requirements to external vendors.

The Procurement Procedure is supported by the Supply Management Services Operations Manual including the "Buying Guide Manual" for use by Purchasing Individuals executing the day to day purchasing transactions on behalf of Hydro One. In addition, HODS document SP 0312 Purchase of External Contractor Services (non Local Purchase Order) further supports the Procurement Procedure and is aligned with the latter policies and procedures.

3.0 Scope

This procedure is broken down into two sections. Section A describes the General procedures relating to the procurement of all goods and services at Hydro One. Section B describes the procedures unique to Tendering.

4.0 Application Rules

4.1 General

4.1.1 Purchasing Individuals Involvement

Procurement transactions are processed by Purchasing Individuals after receipt of a duly authorized Material Request.

Purchasing Individuals must be involved in the procurement process for all goods and services, with the following material and/or service **exceptions:**

- Legal services
- Certain Treasury services
- Certain real estate transactions

Note: although Purchasing Individuals do not have to be involved with the acquisition of these exceptions it is recommended the team responsible for the specific area of procurement develop a procedure to manage the procurement consistent with the Procurement Policy and appropriately approved by the President and CEO.

The procurement process includes market analysis, going to market, selection of suppliers, making contractual commitments to external vendors, and amendments to existing contracts incorporating changes to terms and conditions, pricing (up or down), scope, quantity (up or down), scheduling, cancellations, and terminations.

4.1.2 Local Purchasing/Corporate Charge Card

The following provides direction around Local Purchasing and use of Corporate Charge Cards:

The Corporate Charge Card (CCC) is a method of payment for business expenses and some low value purchases (Local Purchasing). All purchases regardless of the method of payment must follow the Procurement Policy including the requirement for proof of insurance and WSIB coverage where applicable. The Procurement Policy can be found at
http://finance.hydroone.com/Supply_Chain_Services/Policies_and_Procedures/default.htm.
The Corporate Charge Card procedures including Local Purchase Procedure can be found at
http://finance.hydroone.com/PolicyProc/default.htm.

HODS SP0155 Local Contractor and Material Purchase Process (under $15,000 value) shall be followed when making local purchases.

All purchases greater than $15,000 require a Purchase Order (PO) and involvement by Purchasing Individuals and are not to be considered Local Purchases Under limited circumstances, when approved by Supply Chain, the CCC may be used as the method of payment where a Purchase Order/contract exists. Many of the vendors on Hydro One's Approved Contractor's List (ACL) are paid via the CCC and have established Purchase Orders with each of the vendors.

4.1.3 Purchase Order

Formal Purchase Orders are required for all material and service purchasers where "Local Purchasing" authority has not been exercised. See section entitled "Local Purchasing" of this document for details.

The Purchase Order and supporting contract documents must accurately reflect the agreed upon terms and conditions under which the contract was awarded. Any changes to the original contract terms and conditions must be adequately justified, appropriately approved and properly documented.

4.1.4 Single Source

Hydro One's policy is to acquire, where practical, competitive bids for its purchases to maintain the integrity and transparency of the procurement process and ensure best value for dollars spent. When exceptions must be made formal review and approval by Manager, Supply Chain is required in advance with the exception of Emergency requirements where the approval is obtained after the fact.

A "Single Source" situation arises when it is either not possible or it is impractical to obtain the required material or services through the normal competitive processes. Such situations may exist when:

- there is an absence of competition for technical reasons and the goods or services can be supplied only by a particular supplier and no alternative or substitute exists;
- there is only one supplier with the required capability or legal rights to sell the material or service required;
- there is only one supplier who can do the work without causing Hydro One to suffer an unacceptable delay or incur unreasonable costs to another supplier' learning curve;
- it is necessary to ensure compatibility with existing products or to recognize exclusive legal rights, such as exclusive licenses, copyright and patent rights;
- duplicate equipment or parts are required to avoid expensive modifications to adapt to goods of a different design;
- specialized products must be maintained by the manufacturer or its representative
- urgency is created by circumstances or actions of persons external to Hydro One.
- work is to be performed on or about a leased building or portions thereof that may be performed only by the lessor;
- work is to be performed on property by a contractor according to provisions of a warranty or guarantee held in respect of the property or the original work;
- purchasing subscriptions to newspapers, magazines or other periodicals;
- procurement of real property
- utilities or government agencies or regulatory authorities

A single source may also be considered:

- as part of a strategy involving security of supply, the competitive nature of the work or when a specific vendor is selected as a partner in a proposal for external work
- for the procurement of a prototype or a first good or service to be developed in the course of and for a particular contract for research, experiment, study or original development, but not for any subsequent purchases; and
- for the purchase of goods under exceptionally advantageous circumstances such as bankruptcy or receivership, but not for routine purchases.

In all cases where there is a perceived requirement to engage in a Single Source relationship with a supplier for material and services having a value greater than $15,000 and in the case of Consultants greater that $50,000, the justification for such must be documented. All such potential purchases are to be approved by Manager, Supply Chain prior to any discussion with the supplier. Once approved, involvement by a Purchasing Individual is required for all discussions with the supplier relating to the acquisition.

4.1.5 Emergencies

Material or services required to handle an emergency may be obtained in the most expeditious manner at the time of the emergency.

An emergency is a circumstance in which immediate action is required to:

- protect property from damage or destruction; or
- prevent injury to person; or
- restore operation due to the unplanned outage of any transmission, or distribution facility of the Corporation.

Purchases made based on the above are required to be documented, after the fact, with the appropriate justification and approvals (one level higher) and forwarded with the Material Request to the Purchasing Individual. The ensuing Purchase Order will include the words "Emergency Purchase. Confirmation Only, Material/Service already received".

> **Note:** when transactions are automatic through a BPO the Material Request must clearly state - Confirmation only, for Payment Purposes Only, Material Already Received.

4.1.6 Competitive Bids

Where the value of the requirement is less than $15,000 the market is to be surveyed periodically (at least annually) in order to confirm that suppliers are in fact providing competitive prices and a competitive service. When it is confirmed, competition need not be solicited for each purchase. The Purchasing Individual is to document the basics upon which the discretionary authority was exercised. Where this is not confirmed, competitive prices are to be solicited.

Where the value is $15,000 or greater, competition is to be sought in accordance with section entitled "Solicitation of Supplier Pricing and Information - Closings, Openings, Late Submissions, Corporate Seal and Bid Security" of this document.

Competitive bidding is **not** required for: any material and/or service (including the provision of licenses /and permits) where:

- Single Source approval has been obtained
- Emergency requirements
- Local Purchase less than $15k
- Consultants less than $50k

There may be instances where the price or rate has been approved by a regulatory authority or established in accordance with regulatory requirements; in such cases the requirement may be secured from the source offering the highest level of service evaluated through a competitive process or as a result of the provision of sound rationale through a duly approved request for Single Source.

4.1.7 Hiring Consultants And Contractors

The purchase of contractor and consulting services must comply with Hydro One's policies and procedures including the Procurement Policy, Procurement Procedure, Corporate Policy on Consultants, Corporate Procedure for Retention of Consultants (including contract/rental staff not on Hydro One payroll) and HODS SP0312 - Purchase of External Contractor Services (non Local Purchase Order).

Several key elements of the Hydro One policies and procedures are as follows:

- All contractor or consulting engagements must include a process to ensure that the supplier will not be deemed to be an employee of Hydro One.
- Each contractor/consultant is to provide a *WSIB Clearance Certificate*.
- When the *WSIB Clearance Certificate* is not available, the contractor/consultant must complete the "WSIB Independent Operator/Worker Questionnaire to determine their status. The questionnaire is to be signed by both the contractor/consultant and the Hydro One requisitioning manager and forwarded to our Disability Management Consultant (Sue Wabb) for filing with the WSIB. The WSIB will provide a written ruling regarding the individual's status. In making this determination, the WSIB will use the same criteria as Revenue Canada uses in determining

whether a contractor/consultant is an employee of the corporation for source deduction purposes (i.e. income tax, CPP, and EI).

- Any contractor/consultant that the WSIB deems to be a worker (i.e. an employee of Hydro One) can only be hired as a temporary employee and is to be placed on the Hydro One payroll. If the contractor/consultant is unwilling to work on a "temp or agency basis, the individual shall not be retained and other options must be considered.
- If an individual is misclassified by Hydro One as a provider of consulting/contractor services when the individual would actually be deemed to be an employee by the WSIB and the Canada Revenue Agency ("CRA"), this will result in Hydro One being assessed fines, interest, and penalties by Revenue Canada and the Ontario Ministry of Finance in addition to having to remit both the employee and employer portions of the CPP and EI, as well as the Employer's Health Tax.

Proposals may be solicited directly by the Requisitioner where the value of the Consultant engagement is less that $50k. The work must not be of an ongoing nature and the engagement must have the approval of the appropriate authority under the OAR element for Consulting. In such cases, there is no requirement for Single Source approval and the Purchasing Individual will finalize the Purchase Order in PassPort to facilitate payment ensuring that the contractual terms are complete including all insurance and security requirements.

4.1.8 Qualifications Of New Potential Suppliers

With the exception of requirements that are publicly advertised either in the newspaper or on Hydro One's external website, Hydro One will normally seek and qualify a restricted number of potential suppliers to the extent necessary to assure at least two competitive and conforming bids. Additional sources will only be considered if it is deemed to be in the best interest of Hydro One and its customers.

4.1.9 Decision Rules

Qualification of potential suppliers will be on the basis of their ability to perform the work and fully meet all of Hydro One's requirements including: technical, commercial, quality, regulatory, and environmental; and other Corporate objectives. Consideration will be given to life cycle operating costs, including reliability and maintenance factors, delivery assurance, administrative costs and commercial risks.

Factors which will be considered when determining potential sources of supply will include items such as but not limited to:

- Supplier qualification costs
- Financial viability of the company
- Foreign exchange exposure
- Transportation, brokerage, and duty costs
- Contract administration and communication costs
- Local available repair/servicing capability
- Local stocking of products
- supplier surveillance costs
- Cost of changing suppliers
- Supplier capability
- Supplier performance not injurious to Hydro One's reputation
- Health, Safety and Environment requirements and performance

- Insurance
- Equipment Certification
- Supplier references, past experience and past performance

4.1.10 Local Preference/Buy Canadian

Hydro One does not have a local preference or buy Canadian policy. Any benefits attributed to local or Canadian content or presence are to be factored into the evaluation as quantifiable and measurable attributes such as the impact to Total Cost of Ownership based on the response time for on-demand services or after purchase warranty services etc.

4.1.11 Blanket Purchase Orders

A blanket purchase order ("BPO") is established when a contract is awarded to a vendor for the supply of product(s) or service(s) for a defined period of time. The BPO agreement is awarded through the RFx process or in exceptional cases a Single Source approval. The BPO is established to manage repetitive high volume purchases. A BPO is an internal control and process for processing orders.

A BPO agreement must have a finite duration, an administrable means of determining price and must clearly identify the type of material/services to be acquired.

Purchasing Individuals maintain accountability for ensuring that purchases using BPO agreements are within the boundaries of the Procurement Policy and these procedures. Non-exclusive Blanket Purchase Orders are unique and Purchasing Individuals can be contacted for determining the appropriateness of their use.

4.1.12 Development Of A Blanket Purchase Order

The BPO agreement must incorporate:

- a pricing structure that is clear and concise;
- a no-cost cancellation provision;
- a statement that no minimum purchase amount is committed.
- a contract to identify the terms and conditions under which the Product(s) and/or Service(s) are acquired.

The following controls must be developed by the Purchasing Individual when a BPO is used:

- A mechanism to track the value of purchases made against the BPO to ensure that the total funding amount is not exceeded without the appropriate prior purchase approval.
- A mechanism to ensure that the BPO is used only for the purchases for which it was approved.
- A mechanism to measure that the vendor is adhering to the terms and conditions of the contract.

4.1.13 Request And Receipt Of Quotations/Tenders For Blanket Purchase Orders

Tendering, proposal or quotation documents must clearly state that the request covers BPO requirements and must indicate the conditions applicable, i.e. duration of the proposed contract; geographic location of deliveries, disclaimer of guarantees to the successful tenderer of any minimum number of items or value, a forecast of estimated quantities or usage, ; no-cost cancellation provisions; etc. The evaluation of the submissions must take into account historical or forecasted usage, delivery, transportation and/or mobilization cost, delivery and/or mobilization time, payment terms, escalation and all other costs and requirements specific to the commodity being purchased. The terms should allow for a one time extension of the expiry date as a contingency to allow for scheduling of the tender process based on either resource constraints or finalizing specifications.

4.1.14 Approval Of Blanket Purchase Orders

Requisitioning authority and purchase approval for material/services to be purchased under BPO agreements are to be obtained prior to award of the BPO. Where the BPO covers the requirements of multiple lines of business, requisitioning authority is obtained on each individual release and not on the cumulative estimated value prior to award of the BPO. In such cases, the selection of the supplier and the terms and conditions of the agreement are to be approved by the appropriate Purchasing authority equal to the estimated total/maximum value of the contract, for the duration of the contract, prior to the execution of the contract. Estimated total/maximum values are not to be disclosed to vendor. The contract is to be established on an as required basis with no commitment to value or volume of business.

4.1.15 Changes To Blanket Purchase Orders

The pricing of the BPO agreement shall be monitored to ensure all invoices and price increases or decreases are in accordance with the established terms.

Changes to the estimated value/maximum of the contract and/or significant changes to the terms and conditions require appropriate approvals consistent with OAR based on the new cumulative estimate.

Items on a BPO should only be added if there has been a competitive RFx for that item(s). If 2 or more companies with existing BPO's are capable of supplying the new item the RFx may be directed privately to these companies without advertising the requirement. If there is only one company with a BPO the normal competitive process should be followed.

Adding an item(s) to a BPO without competition requires Single Source Approval.

The Purchasing Individual is required to develop an annual plan for taking all expiring BPOs to market with a transition plan to ensure a continuity of supply until the new contract is implemented.

4.1.16 Solicitation Of Supplier Pricing And Information - Closings, Openings, Late Submissions, Corporate Seal And Bid Security

Purchasing Individuals utilize a number of different methods for solicitation of information and pricing from vendors. Below are the different methods and a description of how, when and why they are utilized. Note: where service or material is not available in Canada, advertisements may be placed in media outside Canada.

RFEI - Requests for Expression of Interest

- Are a focused market research tool used to determine vendor interest in a proposed procurement.
- Are generally solicited by public advertisement and posted on external web-site. No estimates are solicited. RFEI documents will be provided to all vendors requesting documents. Should Hydro One decide to proceed to RFx stage, ensuing RFx process will be by private solicitation.
- Are opened privately
- Acceptance of late submissions is at the sole discretion of Hydro One

- There is no requirement for a Corporate Seal or Bid Security
- Closes to Proposal Depository
- Are not used to pre-qualify, screen vendors or short-list Not a substitute for competitive process
- Do not directly result in a contract

RFI - Requests for Information

- Are a market research tool used to determine what products and services are available, scope business requirements and/or estimate project costs. May be solicited by private invitation or by public advertisement. All vendors responding to Public Advertisement or web-site posting will be provided with RFI documents. Should Hydro One decide to proceed to RFx stage ensuing RFx process will be by private or advertised solicitation as dictated by the estimated value and, as a courtesy, should be directed to those that responded to the RFI
- May be closed to the Purchasing Individual or the Proposal Depository at the discretion of the Purchasing Individual and can be received by mail, e-mail or fax.
- Are opened privately
- Allow acceptance of late submissions at the sole discretion of Hydro One. Late submissions are generally accepted.
- Have no requirement for a Corporate Seal or Bid Security
- Are not used to pre-qualify, screen vendors or short-list Not a substitute for competitive process
- Do not directly result in a contract

RFPQ - Requests for Pre-qualification

- Is a procurement tool used to pre-qualify vendors or products, usually based on financial or technical criteria. Generally done by Public Advertisement and posted on the Hydro One external web-site. RFPQ documents will be provided to a vendors requesting documents. Should Hydro One decide to proceed to RFx stage, RFx will be by private invitation to only those vendors that have "Pre-qualified".
- Close to the Proposal Depository
- Are opened privately
- Allow acceptance of late submissions at the sole discretion of Hydro One. Vendor's submitting late Pre-qualification submissions and that are not being considered shall be informed in writing.
- Have no requirement for a Corporate Seal or Bid Security
- Are generally to be posted on Hydro One external web-site
- Are evaluated based on pre-described evaluation criteria
- May directly result in a general services agreement.

RFP - Requests for Proposal

- Are used to solicit vendor proposals for the supply of Consulting services or services for which suppliers must develop and propose a business application or solution. Suppliers may be requested to present their qualifications to do the work for Hydro One's review and acceptance. Any other uses of an RFP such as for complex products, and/or general services requires Manager, Supply Chain approval
- Usually involve defined scope of work that describes what the Service Provider is to do and a defined deliverable product
- Evaluation includes consideration to the quality of the resources, idea, concept or solution proposed along with price, schedule, commercial terms etc.
- Evaluation generally includes mandatory and rated criteria
- If the value of the requirement is estimated to be less than $5 million and if there are multiple

known vendors, a pre-qualification .process may be followed. If there is insufficient market intelligence to ensure that the market is represented, RFP by public advertisement should be considered.

- Are required to be publicly advertised and opened privately is estimated at $5million or greater
- Proposals close to the Proposal Depository on the 15th Floor and are opened privately. Proposals may not be submitted by mail, e-mail or fax
- Late submissions are generally returned unopened.
- Have no requirement for a Corporate Seal or Bid Security
- Are posted on Hydro One external web-site unless a pre-qualification process has been followed and/or the requirement is of a highly confidential nature.
- Proposals may be solicited directly by the Requisitioner where the value of the Consultant engagement is less that $50k. The work must not be of an ongoing nature and the engagement must have the approval of the appropriate authority under the OAR element for Consulting. In such cases, there is no requirement for Single Source approval and the Purchasing Individual will finalize the Purchase Order in PassPort to facilitate payment ensuring that the contractual terms are complete including all insurance and security requirements.
- May directly result in a contract.

RFQ - Requests for Quotation

- Used to solicit price submissions usually for materials and Construction & General Services estimated at less than $250k
- Evaluation process focuses on price, delivery and quality standards. Information obtained verbally must be confirmed in writing, on the supplier's letterhead, or on the Purchasing Individual's RFQ and filed in the purchase order file
- Close to the Purchasing Individual, are opened privately and may be submitted by mail, e-mail or fax
- Late quotations may be accepted at the sole discretion of Hydro One provided that pricing, as in the case of Construction and General Services requirements, has not be disclosed. Vendor's submitting late Quotation submissions and not being considered shall be informed in writing.
- There is no requirement for a Corporate Seal or Bid Security
- May directly result in a contract.

RFT - Request for Tender

- Used to solicit price submissions usually for Materials, Engineered Equipment, and Construction & General Services estimated at $250k or greater. Evaluations focus primarily on Total Cost of Ownership. Submissions must meet stated delivery requirements and quality standards. Bids must be in a sealed envelope (Sealed Tender) and delivered to the specified location (Tender Depository) on time. All submissions are time and date stamped.
- Corporate Seal, Bid Security, signatures, copies of bids required etc. are specified, as appropriate, in the RFT and are to be adhered to by bidders.
- Tenders may be called by Public or Private Invitation (see Appendix - Value Tables) and may close privately or publicly dependant on the type and value of the requirement. Public openings take place in an unrestricted setting under the authority of the Hydro One Manager Supply Chain or agent, supervised by the Tenders Officer. Public Openings are generally reserved for requirements estimated at $5million or greater.
- All tenders for services and materials that are to be opened publicly require Bid Security. Incorporated companies submitting bids requiring Bid Security require a Corporate Seal. Bid Security can be waived at the discretion of the Manager Supply Chain. When waived, it is not necessary to ask companies to submit tenders under Corporate Seal. See also entitled Bid Security

of this document.

- Those opened privately do not require Bid Security or a Corporate Seal
- Tenders cannot be received by fax or e-mail
- All tenders must be received prior to the specified closing date and time. See also section entitled "Invalid Tenders" of this document. All tenders received require at least one copy with an original signature of a signing officer of the vendor submitting. After consulting with the Manager, Supply Chain, the Tenders Officer, or delegate, will accept a privately invited late tender for one of the following reasons:
  - it is a single source tender;
  - it was the only tender received
- Generally are posted on Hydro One external web-site unless a pre-qualification process has been followed and/or the requirement is of a highly confidential nature.
- May directly result in a contract.

4.1.17 Cancelled Requirements

Upon being notified of a requirement being cancelled, the Purchasing Individual will advise all bidders or in the case of the cancellation prior to closing all potential bidders and the Tenders Officer, if applicable. In the event that a response to the tender was received prior to the closing such tender will be returned unopened to the respondent. Cancellation of the requirement and the reasons for the cancellation must be confirmed in writing to all of the potential bidders. Hydro One's external web-site postings are to be marked as cancelled.

When tenders are cancelled where bid security cheques were required, the bid security cheques are to be returned immediately by the Tenders Officer upon notification by the Purchasing Individual.

4.1.18 Withdrawal Of Submissions

A tender, quote or proposal may be withdrawn by the vendor without penalty at any time prior to the stipulated closing time. Purchasing Individuals shall ensure all requests to withdraw submissions are received in writing.

The law permits a bidder to withdraw an offer at any time prior to its acceptance. If, however, the tender is submitted under Corporate Seal with a statement that it is irrevocable for a specified period, it cannot be withdrawn during that period. If the tenderer refuses to enter into a contract on the basis of an offer so submitted, the tenderer becomes liable for the amount of the damages to the other party. Where bid security accompanies the tender (which is required under these procedures with respect to publicly opened tenders) the specified amount of the bid security can be considered the amount of such damages if the proper provisions are included in the terms of the invitation.

Notwithstanding this entitlement, the usual corporate practice is to caution the tenderer that it is liable for damages and that in addition, it may be denied future business opportunities.

> **Exception**
> If the request to withdraw its tender is based upon a substantial error in the tender which is clearly evident on the face of the tender, it is Hydro One's practice to permit the tender's withdrawal, without penalty. The Manager Supply Chain shall be consulted in such cases.

4.1.19 Contract Standards

Hydro One's Contract Standards are standard terms and conditions forming part of the RFT, RFP, and RFQ and in some instances the RFPQ documentation and will ultimately form the basis of ensuing Contracts. The Purchasing Individual will select the appropriate Contract Standard for use based on each individual requirement and will develop, with the assistance of support groups such and Law, Finance, Risk and Insurance, "Special Commercial Conditions" as required. The following lists the current contract standards: Guidance around their use can be obtained from Purchasing Individuals:

A-1	Equipment and Materials
A-5	Engineered Equipment
A-10	Construction Services
A-11	Major Construction Work
A12.2	Installation (Erection) of Major Equipment
A-18	Minor Services
A-19	Supply of Chemical and Gas Products
A-21	Rental of Reproduction Equipment
A26	Building Construction
A-27	Hazardous Waste and Subject Waste
A-28	Assessment and Remediation of Contaminated Sites
A-29	Consulting Services
A-30	Supply and Installation of Telecommunications Systems
A-31	Supply of Data Processing Equipment
A-36	Building Consultants

4.1.20 Escalation

Hydro One prefers to conduct business on the basis of firm prices. While recognizing the uncertainties concerning trends in the cost of currency, labour and materials in long-term contracts, Hydro One may enter into a contract with prices subject to escalation provided that the value of the contract exceeds $500,000 and delivery extends beyond one and one half (1 1/2) years from date of tender or if Hydro One deems that entering into a contract under these terms is likely to be most beneficial. The potential effects of escalation are to be considered in the evaluation of submissions and support from Corporate Finance should be sought to conduct present worth evaluations for these purposes.

4.1.21 Evaluation Of Submissions

Purchasing Individuals and/or the evaluation team in conjunction with the Purchasing Individual must develop a disciplined and comprehensive evaluation process prior to the closing date for submissions. The approach shall include mandatory requirements and any weights for rated requirements. No assumptions are to be made. The submission is to be evaluated based on its content. If necessary, clarifications will be sought from the bidder by the Purchasing Individual. Evaluations will focus on mandatory criteria, rated requirements and pricing. Pricing and Total Cost of Ownership, as applicable, shall have the maximum weightings justifiable. In the request for submission, vendors will be disclosed the mandatory requirements and the other rated criteria will be stated. Rated criteria are desirable attributes of the submission but are not considered "musts". Weightings are not disclosed to bidders although their relative importance such as High, Medium or Low may be disclosed. Total Cost of Ownership will consider life time operating costs including reliability and maintenance factors, delivery assurance, Change Over Costs, administrative costs and commercial risks. Such costs may be considered in the evaluation of submissions only when the criteria is identified to the bidder in the RFx document.

Dependant on the complexity and value of each individual requirement and the evaluation criteria stipulated, cross-functional evaluation teams may be established. The Purchasing Individual participates in all evaluation teams and generally leads the team. In the case of requirements where the evaluation focuses on price while meeting delivery and quality requirements, the Purchasing Individual generally completes the evaluation and forwards the recommendation to the stakeholders for approval/concurrence.

4.1.22 Custom Services

All Corporate importing and exporting is coordinated through the Transportation Department, Supply Management Services, Inergi LP ("Transportation Department").

4.1.23 Foreign Purchase

For foreign purchases where Hydro One is the Importer of Record, detailed instructions are available from the Transportation Department.
In instances where Hydro One is not the Importer of Record the Transportation Department is available to assist in duty reductions and customs instructions.

4.1.24 Financial Viability Of Potential Contractors

Hydro One will ensure the companies it contracts with are financially sound by ensuring a "proof of ability' clause which requires the submission of recent financial statements is included in all requests for submissions that present risk to Hydro One. This clause will be inserted by the Purchasing Individual. Generally this includes all potential contracts in excess of $350,000 and without exception the clause is to be included in all potential contracts $1 million or greater and all long term contract in excess of $350,000. A financial evaluation is to be conducted on the recommended company for all such contracts

> **Exception**
> Contracts that do not present undue risk to Hydro One, due to their nature, do not require financial evaluations and/or the inclusion of financial data and performance bond clauses in the tendering document.

These types of contracts must satisfy the following conditions:
for equipment and materials:

- available from two or more sources on an interchangeable basis; and
- available on short lead time/spot purchases
- for construction and services:
- can be assumed in mid-stream with little or no disruption to schedules;
- is widely available at competitive prices.

The purchase approval document is to contain a statement that the procurement satisfies the appropriate conditions, no financial evaluation was performed, but, notwithstanding this, there is no undue risk.

Note: The above exceptions do not apply to all potential contracts $1 million or greater and all long term contract in excess of $350,000

4.1.25 Obtaining Financial Protection

Where as a result of the evaluation it becomes evident that the financial condition of a prospective supplier is likely to cause undue risk of non-completion, one (or more) of the following courses of action is to be taken:

- obtain a parent company guarantee;
- obtain a bank guarantee;
- obtain a performance bond* (see Performance Bond sub-section below);
- consider progress payment security registration;
- obtain a monetary deposit for retention; or
- award the business to a different supplier.

The Manager Supply Chain decides whether or not financial protection is required and the form it is to take. Where the form of protection is a parent company guarantee, bank guarantee, or retention of deposit, the Purchasing Individual will arrange a suitable agreement with the company; assistance from Law Division will be requested as required. Any agreements with regard to a parent company guarantee are to include the provision that the parent company's financial statement is to be provided on an annual basis. Any agreements relevant to the guarantee or to the retention of the deposit must be reviewed by Law and by Manager, Supply Chain.

4.1.26 Performance Bonds

- The performance bond is to be provided by a surety licensed to issue such bonds in Ontario.
- The surety is to remain on the bond through to completion of all obligations of the contractor under the contract.
- The cost of the performance bond is normally borne by the vendor. Failure to furnish a performance bond within a reasonable period of time from the date that
- Hydro One asks the request will result in the contractor failing to receive the business and the forfeiture of its bid security, where applicable.
- Inquiries from the surety are to be answered by the Purchasing Individual.
- Hydro One's form of bond provides that notice to the surety of contractual changes is not required.

4.1.27 Security Checks

Conducting security checks on vendors are among the ways that Hydro One protects its employees, customers, assets and information.

There are three types of security checks conducted by Corporate Security: criminal record, driver's licence and credit ("Checks"). Not all contract staff, consultancy, material or service requirements require that any or all Checks be performed. It is the responsibility of Purchasing Individuals to assess the requirement and determine what appropriate Checks, if any, are required and to ensure the appropriate process is followed and to liaise with Corporate Security as required.

4.1.28 Insurance Requirements

Hydro One has developed standard insurance clauses and standard certificates of insurance to include in the RFx packages. These are applicable for the vast majority of requirements purchased under each given Contract Standard. Purchasing Individuals will ensure the appropriate clauses are included in the RFx. Purchasing Individuals will receive, review and monitor insurance certificates obtained to ensure coverage is current and meets the coverage requirements requested in our request for submission. Purchasing Individuals will provide copies to Director, Risk and Insurance. When products or services are required that may cause increased potential risk to Hydro One or its assets, direction form Director, Risk & Insurance should be sought. When situations arise where a bidder does not meet the insurance requirements stipulated in the RFx and there is a business need to place business with this bidder, approval is to be sought from the Vice President of the LOB with the requirement.

4.1.29 Health, Safety And Environment - Safety Of Hydro One Contractors

HODS document SP0312 - Purchase of External Contractor Services (non Local Purchase Order applies to all Hydro One Networks employees who require the services of external companies/*Contractors* in order to complete a work program. It applies to the purchase of "*Contractor* Services" (general services, and construction services). The purpose of this document is to describe the unique life cycle requirements used when engaging Contractors to perform services for Hydro One. This process is to be used when a formal *Purchase Order*/Contract will be issued by Purchasing Individuals.

4.1.30 Quality Assurance

The Quality Assurance program (standard) to be implemented by a supplier will be determined by the Requisitioner of materials and services. The appropriate selection will be based on any combination of the following:

- the requirement for Hydro One to demonstrate compliance with federal and/or provincial regulations and laws;
- the design authorities' assessment of the degree for potentially latent manufacturing non-conformances from technical specifications that are critical to the safe and reliable operation of the materials and equipment;
- the adoption of recognized international Quality Assurance standards, such as the ISO 9000 series, will be given precedence to satisfy local jurisdiction and/or industry specific standards whenever possible.

In cases where Hydro One has not performed business with a vendor for the supply of materials and services where a standard has been determined by the Requsitioner, it is required that a plant audit be performed to confirm that the vendor has the necessary Quality Assurance measures in place.

4.1.31 Labour Requirements

The following applies to the procurement of construction, services and installation contracts where contracting out trades work being done on Hydro One property.

4.1.32 Preparation Of Tendering Documents

During the preparation of the tendering document, the requisitioning department obtains the appropriate Labour Requirements Clause from the Workforce Acquisition Department. This is accomplished by completing the Request for Wage Schedule and Labour Requirements Clause for Tendering Documents Involving Field Labour form, which details the trades work to be contracted out such as the scope of work to be done by the contractor, labour trades involved, work location, the number of hours, total cost of work, the total cost of field labour, etc.

The Workforce Acquisition Department will only respond to requests for contract Labour Requirements Clauses from requisitioners. The requisitioning department is the only source sufficiently acquainted with the specific details of the work to allow accurate identification of the correct Labour Requirements. The consequences to the Corporation of using an incorrect clause are significant and the procedure used to obtain the Labour Requirements Clause is in place to minimize this risk.

The Purchasing Individual upon request to solicit tenders or quotes for work falling within the scope of this Procurement Procedure, will ensure that the requisitioner has included a Labour Requirements Clause in the tendering document when applicable. There are some instances when labour requirements do not apply and the requisitioner will so specify.

4.1.33 Acknowledgement Of Labour Requirements

It is the responsibility of the Purchasing Individual to ensure that all bidders, when the Form 1 Labour Requirements Clause is used, have included with their submission a signed, sealed and dated Acknowledgement of Labour Requirements form.

4.1.34 Hazardous Materials

The management of hazardous products is legislated under Federal and Provincial Regulations. Consequently, where the material is "hazardous," all regulatory requirements, including Material Safety Data Sheets and Product Labels will be considered, prior to delivery.

4.1.35 Medical Equipment And Supplies

Medical equipment and supplies can only be purchased under the direction of the Chief Physician or authorized personnel.

4.1.36 Private Investigators

Approval must be obtained from Corporate Security prior to the retention of private investigators on behalf of the Corporation.

4.1.37 Disclosure Of Information To Vendors During The Competitive Process

Refer to Appendix - Value Tables

4.1.38 Changes Prior To The Tender, Proposal Or Quotation Closing Date

Where a requirement is changed prior to the closing date and time, an addendum is to be issued by the Purchasing Individual to all potential bidders at the same time.

4.1.39 Debriefing Unsuccessful

For major contracts unsuccessful bidders will, at their request, be invited to a debriefing meeting for the purpose of explaining to them the rationale for the award, including the elements of the evaluation which influenced the selection. Information on competing tenders (including prices) is not to be disclosed nor are the mathematical details of the tender evaluation.

4.1.40 Sales Tax

With very few exceptions, Hydro One companies recover from the Federal Government, all GST paid. For this reason, GST paid to suppliers must be identified and charged to the appropriate GST account.

With respect to Ontario Retail Sales Tax, Hydro One companies require Ontario suppliers to charge Retail Sales Tax wherever it is applicable.

Hydro One Telecom Inc. is registered for Quebec Sales Tax purposes. Since QST paid to suppliers is recoverable from the Quebec Government, QST paid to suppliers by Hydro One Telecom Inc. must be identified and charged to the appropriate QST account.

Appropriate instructions to be used for each purchase with respect to these taxes are available from the Corporate Tax department or from Inergi Supply Management Services and Accounts Payable Services departments.

4.2 Tendering

4.2.1 Invalid Tenders

In order to protect the integrity of Hydro One's tendering system, a rigid policy for the receipt of tenders has been developed. This policy is intended to instill confidence in those who wish to do business with Hydro One, that no favoritism does or can exist.

Once the tender closing date has passed and it is established that a tender was received after the set closing time and date, the Purchasing Individual is advised by the Tenders Officer. The tenderer will be notified by telephone that the tender was received after the stipulated closing time and, therefore, cannot be considered in the evaluation.

Concurrently, a covering letter with the unopened tender will be prepared indicating that the tender is ineligible for consideration by reason of its lateness.

Where a privately opened tender is unsigned or improperly signed, the Tenders Officer, will notify the tenderer of the need to have the tender signed within two working days (four working days for outside Canada). Tenders unsigned after the stipulated time period will be returned to the tenderer.

Publicly invited and publicly opened tenders, omitting a valid signature and/or seal (from corporations) and/or submitted without stipulated bid security, will be rejected and returned immediately following the tender opening, without opportunity for remedy. One submitted copy must contain an original signature of a signing officer of the company. The letter accompanying all returned is to be signed by the Tenders Officer on behalf of the Manager, Supply Chain.

4.2.2 Changes To Tenders During Evaluation

Tenders must be evaluated on the basis of the original tender specifications and the original tender. Changes to tenders received after the tender closing time constitute re-tender and would jeopardize the integrity of our tendering system, if considered in the evaluation.

A change to the tender, received after the closing time will not be considered in the evaluation process regardless of whether the change was offered by, or solicited from, the tenderer(s). Price changes or changes to specifications received after closing and included in the evaluation/recommendation process effectively constitute an unacceptable re-tender.

The Purchasing Individual will arrange and chair all meetings with tenderers. Where the clarification is of a technical nature, the requisitioning department requests the Purchasing Individual to arrange the tender clarification meeting.

Price reductions or increases due to a change in scope may be considered and included in funding approvals provided that they were not given consideration in the evaluation and recommendation process.

4.2.3 Bid Security

Bid security is required only in the public tendering environment. Bid security is a form of protection submitted with a tender that assures the tenderer will enter into a contract if its tender is accepted. The most common forms of bid security are bid bond, deposit of cash or certified cheque, and letter of credit. A letter of credit must be free of restrictions and cashable upon demand in a form acceptable to Hydro One. Hydro One does not accept bid bonds and, for administrative reasons, discourages the submission of cash and bearer bonds. The specified form is certified cheque, but an irrevocable letter of credit is acceptable.

Bid security also acts as a method of prequalification of bidders. The willingness of a bidder to submit a bid security in the form of a certified cheque at risk of forfeiture is evidence of its being a bona fide business enterprise.

Bid security in an amount equal to approximately eight to twelve per-cent (rounded to the nearest thousand) of the estimated value of the requirement (maximum $500,000) is to be forwarded to Hydro One in the form of certified cheque or irrevocable letter of credit. Bid security may be waived at the discretion of the Manager, Supply Chain.

Specific Circumstance

Where bidders are prequalified and tenders are to be publicly opened, bid security and the corporate seal may be waived at the discretion of the Manager, Supply Chain.

Return of Bid Security

Following each public opening, the Tender's Officer will establish the lowest tender accompanied by a valid form of bid security. The bid securities received with the remaining tenders will be returned promptly, within one or two days.

If the bid security of the successful tenderer has been held, i.e. the lowest tenderer, and a performance bond is not required, the bid security cheque shall be returned upon receipt of the signed acceptance copy of the purchase order. In the event there are any changes introduced on the acknowledgement copy, the bid security will be retained until the implications are resolved.

If a performance bond is required, Law will advise the Purchasing Individual when the fully executed performance bond has been received. This action along with the receipt of the signed acceptance copy of the purchase order, provided that there have been no new changes introduced, will initiate the Purchasing Individual to advise the Tenders Officer to release of the bid security.

5.0 References

Corporate Executive Authority Register and Organizational Authority Registers
Hydro One Code of Conduct
Procurement Policy
Hydro One Supply Chain website
Corporate Charge Card procedures
Investment Recovery Procedures
Corporate Policy on Consultants
Corporate Procedure for the Retention of Consultants
SP 0312 Purchase of External Contractor Services (non Local Purchase Order)

6.0 Exceptions (If Applicable)

Any deviations from this procedure are to be approved by Corporate Finance, Manger Supply Chain Services.

7.0 Definitions

Change Over Costs - extra costs which will accrue to Hydro One as a result of things such as the additional need for spare parts where different equipment suppliers are introduced or where other than the incumbent contractor is successful in securing a contract for a future period for a service contract.

Hazardous Materials - for the purposes of this document, the term "hazardous materials," is: "All gases, liquids, pastes, powders, resins (beads), metals and plastics (which may further be fabricated on-site) with properties which if not adequately controlled could result in human illness or injury. "The terms "product" and "material" are considered equivalents.

Importer of Record - an Importer of Record is any person or company receiving goods in Canada that are manufactured and purchased from outside Canada and will "clear" the goods at the point of entry by paying all duties and taxes to Revenue Canada Customs & Excise.

Lump Sum Value - is the total value of the purchase order as it would appear on the face of the order and is consistent with the amount tendered but, in the case of disclosure of information for material requirements, the "lump sum value" must be rounded down.

Quality Assurance - a planned and systematic pattern of all means and actions designed to provide adequate confidence that items or services meet contracted and jurisdictional requirements and will perform satisfactorily in service.

Procurement - the process of obtaining material or services, which embraces the elements of requisitioning, purchasing, contract administration, commissioning and final acceptance.

RFx - Request for Information, Request for Pre-qualification, Request for Quotation, Request for Tender or Request for Tender.

Sealed Tender - a formally structured offer to supply material and/or services, submitted in a sealed envelope or package, with a specific closing date, time and location. The word "sealed" refers to the fact that the tender is submitted in a sealed envelope and not to the corporate seal which is affixed on publicly invited tenders.

Total Life Cycle Cost/ Total Cost of Ownership - the total cost of product over its full life (concept to disposal). Efficiencies including things such as operational costs, power and consumable items (i.e. chemicals) would be part of total cost of ownership considered in the evaluation.

Appendix A: Value Table Of Purchasing Requirements - Consultants

Click to view Appendix A in Word format.

Appendix B: Value Table Of Purchasing Requirements - General Services & Construction

Click to view Appendix B in Word format.

Appendix C: Value Table Of Purchasing Requirements - Material And Engineered Equipment

Click to view Appendix C in Word format.

Appendix D: Document Management

Owner/Functional Responsability	Supply Chain Services
Approval Date	October 24, 2007
Approval Required By	VP Supply Chain Services
Effective Date	October 24, 2007
Document Last Reviewed	August 2008

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Consumers Council of Canada (CCC) INTERROGATORY #36 List 1

Interrogatory

Issue 4.1

36. D1/T1/S1/p. 4

Please specifically identify how the $12 million and $11 million cash working capital requirements for 2009 and 2010 were calculated.

Response

The calculation of the cash working capital requirement for 2009 of $12 million and the cash working capital requirement for 2010 of $11 million from line 20 and line 21 in this exhibit can be found in Table 1 of Exhibit D1, Tab 1, Schedule 3, page 2.

Consumers Council of Canada (CCC) INTERROGATORY #37 List 1

Interrogatory

Issue 4.1

D1/T3/S1/p.2

Please indicate the impact on the 2009 revenue requirement of reducing the 2009 capital budget by $100 million. Please indicate the impact on the 2010 revenue requirement of reducing the 2009 capital budget by $100 million. Please include all assumptions.

Response

Hydro One Transmission uses sound decision making processes to plan and execute the work program and does not forecast a reduction of $100M in the 2009 capital budget. However for illustrative purposes if capital expenditures were reduced by $100M in 2009, and if it is assumed that all capital expenditures are in-service the year of the expenditures, 2009 revenue requirement would be lower by approximately $5M and 2010 revenue requirement would be lower by approximately $10M.

Consumers Council of Canada (CCC) INTERROGATORY #38 List 1

Interrogatory

Issue 4.1

D2/T2/S1/pp. 1-2

In the EB-20067-0501 Decision the Board indicated that it expected HON to provide evidence on 2007 and 2008 capital spending compared to the Board approved budget. Please indicate all components of the evidence where this analysis has been provided. Please recast Exhibit D2/T2/S1 to include the Board approved numbers for 2005-2008

Response

The 2007 and 2008 actuals compared to Board Approved levels are discussed in Exhibit D1, Tab 3, Schedule 1, pages 4 to 6.

There are no "Board Approved" amounts for 2005 and 2006. The last Board approved expenditures for Transmission were in 2000 as part of proceeding RP-1999-0044. The revenue requirement was subsequently approved for 2007 and 2008 as part of proceeding EB-2006-0501

The "Board Approved" values for 2007 and 2008 in included in the table below.

	Historic			Board Approved	Bridge	Board Approved	Test	Test
	2005	2006	2007	2007	2008	2008	2009	2010
Transmission Capital ($ millions)								
Sustaining								
Transmission Stations								
Circuit Breakers	2.5	1.9	0.6	7.6	17.1	9.1	12.5	21.1
Station Reinvestment	12.4	16.5	48.9	64.5	60.0	76.6	64.6	43.5
Power Transformers	34.2	32.0	18.7	33.9	39.3	35.0	50.6	62.5
Other Power Equipment	7.0	8.1	11.5	14.9	14.0	16.7	12.0	21.6
Protection, Control, Monitoring, and Telecommunications	45.4	44.2	44.1	68.2	55.9	58.8	39.3	64.9
Ancillary Systems	6.7	10.7	8.9	15.6	15.9	17.1	13.6	17.2
Transmission Site Facilities and Infrastructure	5.8	7.0	4.0	17.3	43.0	15.1	12.1	13.1

	Historic 2005	Historic 2006	Historic 2007	Board Approved 2007	Bridge 2008	Board Approved 2008	Test 2009	Test 2010
Stations Environment	6.3	6.5	5.9	7.1	2.8	5.6	4.3	3.7
Total Transmission Stations Capital	120.4	126.9	142.7	229.2	248.0	234.0	208.8	247.6
Transmission Lines								
Overhead Lines Refurbishment and Component Replacement	37.6	40.5	46.4	43.9	42.7	44.9	49.1	53.4
Transmission Lines Reinvestment	5.2	9.5	6.2	6.8	5.3	7.9	16.5	16.1
Underground Lines Cable Refurbishment & Replacement	5.8	1.6	14.6	8.2	4.8	8.7	5.6	4.4
Total Transmission Lines Capital	48.6	51.6	67.2	58.9	52.8	61.6	71.2	74.0
Total Sustaining Capital	168.9	178.5	210.0	288.1	300.8	295.6	279.9	321.6
Development								
Inter Area Network Transfer Capability	37.2	67.2	80.5	16.6	130.4	16.6	396.5	509.6
Local Area Supply Adequacy	65.9	27.7	97.4	98.6	73.4	192.7	101.3	50.4
Load Customer Connection	28.0	45.6	53.7	86.9	33.6	132.7	39.0	58.1
Generator Customer Connection	0.0	26.5	38.4	57.7	15.2	3.9	6.0	23.1
Performance Enhancement & Risk Mitigation	3.5	12.4	2.5	59.0	3.7	69.7	7.2	14.2
Smart Grid	0.0	0.0	0.0	0.0	0.0	0.0	3.5	3.4
Total Development	134.6	179.4	272.6	318.8	256.3	415.6	553.4	658.8
Operations								
Grid Operating and Control Facilities	0.8	1.6	2.0	15.1	21.1	17.2	15.1	9.8
Operating Infrastructure	4.8	4.4	2.7	4.9	9.1	3.2	3.1	19.1
Amalgamation of TOCS	4.7	3.4	0.0	0.0	0.0	0.0	0.0	0.0
Total "Operations"	10.2	9.4	4.7	20.1	30.2	20.4	18.2	28.9

	Historic 2005	2006	2007	Board Approved 2007	Bridge 2008	Board Approved 2008	Test 2009	Test 2010
Shared Services and Other Costs								
Transport, Work & Service Equipment	11.6	11.6	13.3	13.5	17.7	12.5	14.5	16.2
Information Technology	20.1	14.9	14.7	10.1	11.9	10.2	10.9	12.3
Cornerstone	0.0	0.0	33.8	57.0	72.5	15.8	50.5	28.4
Facilities & Real Estate	0.8	1.5	3.2	4.0	5.4	4.2	16.3	7.9
Conservation and Demand Management	0.0	0.0	0.0	0.0	0.0	0.0	0.2	0.1
Other	3.0	6.1	7.1	0.0	(1.9)	0.0	0.0	0.0
Total Shared Services & Other Costs	35.5	34.1	72.1	84.6	105.6	42.8	92.4	64.9
Total Transmission Capital	**349.3**	**401.6**	**559.5**	**711.6**	**692.9**	**774.5**	**944.0**	**1074.1**

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Consumers Council of Canada (CCC) INTERROGATORY #39 List 1

Interrogatory

Issue 5.1

F1/T2/S1/p. 1

Did HON consider rebating the regulatory asset account balances over a two-year period rather than a four-year period? If so, why was that proposal rejected?

Response

Please see response to BOMA/LPMA interrogatory #24 in Exhibit I, Tab 2 Schedule 24, part (c) as to why a four year period was selected over a two-year period.

Consumers Council of Canada (CCC) INTERROGATORY #40 List 1

Interrogatory

Issue 5.3

F1/T1/S2/p. 2

HON is proposing to undertake $47.9 million of preliminary work to advance 18 transmission related projects required by the OPA in their IPSP and to incorporate Darlington B GS into the system. Please explain how HON intends to ensure that the work undertaken is being carried out in a cost-effective manner? How will HON demonstrate the prudence of these investments when the costs are brought forward for recovery?

Response

HON believes that the transmission projects identified by the OPA in the IPSP are essential to meet the present and future electricity needs of the province. Hydro One ensures development work is pursued in a cost effective manner by using standardized designs that reduce the volume of engineering work required and by limiting the detailed engineering and estimating work required prior to the preferred option being selected.

Hydro One believes it is prudent and necessary to complete the preliminary work detailed in Exhibit C1, Tab 2, Schedule 3 on a timely basis in order to meet required project in-service dates. As stated in Exhibit F1, Tab 1, Schedule 2, Hydro One is seeking approval from the Board to include these prudently incurred expenditures in a deferral account for disposition and recovery at a future date in accordance with Board direction.

Consumers Council of Canada (CCC) INTERROGATORY #41 List 1

Interrogatory

Issue 5.3

F1/T1/S2/p. 2

With respect to the account being proposed for the IPSP and Darlington preliminary work is HON requesting a variance account (including $19.2 million in rates for 2009/2010 and tracking any variances) or a deferral account (having all costs recovered in a future proceeding). Please explain the rationale for the mechanism selected.

Response

Hydro One is requesting a deferral account to have the costs recovered in a future proceeding. Hydro One has not included any costs for the IPSP and Darlington preliminary work ($19.2 million in the test years) in our application so the deferral account is the appropriate mechanism. This work will be required to meet the required in-service dates set out in the unapproved IPSP. If the IPSP is approved these costs would be capitalized. See Exhibit C1, Tab 2, Schedule 3 pages 5-7 for further information on the IPSP and Darlington preliminary work.

Consumers Council of Canada (CCC) INTERROGATORY #42 List 1

Interrogatory

Issue 5.3

F1/T1/S2/p. 3

Please explain, specifically, how HON defines "any costs that may be shifted from customers to Hydro One Transmission as a result of the Board's interpretation of the code". Please identify how HON intends to account for these costs in its proposed variance account. Is the account only related to cost shifts arising from Board changes to the TSC? If not, please provide a list of all potential circumstances that might apply.

Response

This account relates to cost shifts that may arise from Board changes to the TSC (e.g. stemming from a review of connection cost responsibility) or from reviews/ interpretations by the Board or its staff of Hydro One's previous applications of the TSC with respect to capital contributions.

Please see response to Ontario Energy Board interrogatory # 86 in Exhibit I, Tab 1, Schedule 86.

Great Lakes Power (GLP) INTERROGATORY #1 List 1

Interrogatory

Issue 5.3
Are the proposed new deferrals/variance accounts appropriate?

Reference: Exhibit C-1, Tab 2, Schedule 3, Page 6 and 7, Table #1

Hydro One sets out in Table #1 a summary of development work for the IPSP and other long-term projects:

a) Has Hydro One received any indication either from the Ministry of Energy, the Ontario Energy Board or the Ontario Power Authority that it has been designated as the transmitter to develop and operate the projects identified in Table #1?

b) If yes, please describe in detail the nature and extent of the designation together with all written correspondence in that regard.

Response

a) No, Hydro One has not been designated as the transmitter to develop and operate any of the projects identified in Table #1.

b) Not applicable.

Great Lakes Power (GLP) INTERROGATORY #2 List 1

Interrogatory

Issue 5.3
Are the proposed new deferrals/variance accounts appropriate?

Reference: Exhibit C-1, Tab 2, Schedule 3, Page 7

With respect to the costs identified in Table #1, do the costs included in Table #1 reflect indirect and direct costs or just direct costs applicable to the development activity for each project?

a) If the costs are both direct and indirect costs, on what basis are the costs allocated?

b) Please provide a breakdown of the direct and indirect costs on a project-by-project basis.

c) If the costs are direct costs only, do the indirect costs associated with the activity in question appear elsewhere in Hydro One's cost of service? If so, in what aspects of the cost of service and how much for each project listed?

d) Will Hydro One seek to capitalize the amounts recorded in the requested deferral account at a later date?

Response

a) The costs are only direct costs.

b) Not applicable.

c) There are no indirect costs specifically associated with the development activity for these projects.

d) No, Hydro One will be seeking disposition and recovery of the amounts recorded in the deferral account at a future date in accordance with Board direction, as stated in Exhibit F1, Tab 1, Schedule 2, Page 2, Lines 4-6.

Great Lakes Power (GLP) INTERROGATORY #3 List 1

Interrogatory

Issue 5.3
Are the proposed new deferrals/variance accounts appropriate?

Reference: Exhibit C-I, Tab 2, Schedule 3, Page 7

Please describe in detail the work to be undertaken in the bridge and test years for projects identified in Table #1 by the numbers 5 through 9 and number 15.

Response

For the projects referred to above, the work to be undertaken is known as Pre Engineering or "Project Development Work". The scope of this work is described in detail in Exhibit C-1, Tab 2, Schedule 3, Page 6, Lines 5 to 13.

Great Lakes Power (GLP) INTERROGATORY #4 List 1

Interrogatory

Issue 5.3
Are the proposed new deferrals/variance accounts appropriate?

Reference: Exhibit C-1, Tab 2, Schedule 3, Page 6.

Exhibit C-1, Tab 2, Schedule 3, Page 6 states that "The pre-engineering spending required to support the IPSP projects and the incorporation of Darlington "B" GS are provided in Table 1 ." Note 1 of Table 1 states "'Total' costs include cash flows, if any in the years before 2009 and after 2010". With respect to clarifying the meaning of Note 1, does this Note mean that preengineering spending required to support the IPSP projects was made before 2008? If yes, please provide the expenditures that were incurred prior to 2008 for the projects identified as numbers 5 though 9 and number 15 of Table #l .

Response

No, there were no expenditures before 2008.

Great Lakes Power (GLP) INTERROGATORY #5 List 1

Interrogatory

Issue 4.1
"Are the proposed 2009 and 2010 Sustaining and Development and Operations Expenditures appropriate, including consideration of factors such as system reliability and asset condition?"

Reference: Exhibit D-1, Tab 3, Schedule 3, Page 33

According to Table #2 of Exhibit D-1, Tab 3, Schedule 3 relating to "Inter-Area Network Transfer Capability Summary of Development Projects in Excess of $3 Million", the amount of "Other Projects (< than $3M) with 2009 - 2010 Cashflows" increase from $l.lM in 2007 to $5.2M in 2008 (372% increase) with a further increase in 2009 and 2010 of $1.2M (23%) and $2.2M (34%) for each year.

a) Please explain in detail the drivers underlying the significant increase from 2007 to the bridge year.

b) Please explain in detail for the increase in Expenditures from 2008 to 2009 and from 2009 to 2010.

c) Do any of the expenditures for 2008, 2009 and 201 0 in the "Other Projects" category of costs relate to projects identified in Table #1 of Exhibit C-1, Tab 2, Schedule 3? If so, to which projects do they relate and please provide in detail a description of the activity and a breakdown of the corresponding expenditures.

Response

a) The numbers shown for 2007 and 2008 simply reflect the cashflow for these years associated with projects that have 2009 and 2010 cashflows in the current Application with. A project that has 2009-2010 cashflows is typically moving from the early development phase to the construction phase in the 2007 to 2008 timeframe.

b) For the same reason cited in a), projects with 2009 and 2010 cashflows will be continuing to move through the development phase and into the construction phase between 2008 and 2010, accounting for the difference in annual expenditure.

c) No they do not.

Great Lakes Power (GLP) INTERROGATORY #6 List 1

Interrogatory

Issue 4.1
"Are the proposed 2009 and 2010 Sustaining and Development and Operations Expenditures appropriate, including consideration of factors such as system reliability and asset condition?"

Reference: Exhibit D-1, Tab 3, Schedule 3, Pages 33 and 34

According to Table #3 of Exhibit Dl, Tab 3, Schedule 3 relating to "Local Area Supply Adequacy: Summary of Development of Projects in excess of $3 Million", the amount of "Other Projects" (< than $3M) with 2009 - 2010 Cashflows" increased from $1.5M in 2007 to $5.9M in 2008 (293% increase) and a further increase in 2009 from $5.9M in 2008 to $6.3M in 2009.

a) Please explain in detail the drivers underlying the significant increase Expenditure from 2007 to the bridge year.

b) Please explain in detail the drivers underlying the increase in Expenditures from 2008 to 2009.

c) Do any of the expenditures for 2008, 2009 and 2010 in the "Other Projects" category of costs relate to projects identified in Table #1 of Exhibit C-1, Tab 2, Schedule 3? If so, to which projects do they relate and please provide in detail a description of the activity and a breakdown of the corresponding expenditures.

Response

a) The same rationale as provided in the response to interrogatory Exhibit I, Tab 12, Schedule 5, part a) applies to the referenced work in Table 3.

b) The same rationale as provided in the response to interrogatory Exhibit I, Tab 12, Schedule 5, part b) applies to the referenced work in Table 3.

c) No they do not.

Great Lakes Power (GLP) INTERROGATORY #7 List 1

Interrogatory

Issue 4.1
"Are the proposed 2009 and 2010 Sustaining and Development and Operations Expenditures appropriate, including consideration of factors such as system reliability and asset condition?"

Reference: Exhibit D-1, Tab 3, Schedule 3, Pages 33 and 34

At Exhibit C-1, Tab 2, Schedule 3, Table #1, Hydro One sets out the projects for which it seeks to establish a deferral account related to various development expenditures. Referring to Table #1 of Exhibit C-1, Tab 2, Schedule 3, are any of the expenditures in the bridge year, 2009 and 2010 set out in Tables 1, 2 or 3 of Exhibit D-1, Tab 3, Schedule 3 attributable to any of the projects set out in Table #1 of Exhibit C-1, Tab 2, Schedule 3?

a) If so, which projects and what expenditures are attributable?

b) Are any of the Expenditures referred to in Tables 1, 2 or 3 of Exhibit D-1, Tab 3, Schedule 3 also included in the expenditures set out in Table #1 of Exhibit C-1, Tab 2, Schedule 3? If so, what are the expenditures and explain in detail the rationale related to the duplication.

Response

None of the expenditures identified in Tables 1, 2 or 3 of Exhibit D1, Tab 3, Schedule 3 are attributable to any of the projects on Table 1 of Exhibit C-1, Tab 2, Schedule 3.

a) Not applicable

b) No they are not.