Amanda Klein
Director, Regulatory Affairs
Toronto Hydro-Electric System Limited
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October 5, 2012

via RESS e-filing – signed original to follow by courier

Ms. Kirsten Walli
Board Secretary
Ontario Energy Board
PO Box 2319
2300 Yonge Street, 27th floor
Toronto, ON M4P 1E4

Dear Ms. Walli:

RE: Toronto Hydro Electric System Limited ("THESL")
Application for 2012, 2013 and 2014 IRM Rate Adjustments and ICM Rate Adders – Responses to Interrogatories
OEB File Number: EB-2012-0064

THESL writes in respect of the above-noted matter.

THESL received interrogatories from OEB Staff, Association of Major Power Consumers in Ontario ("AMCO"), Consumers Council of Canada ("CCC"), Canadian Union of Public Employees, Local One ("CUPE"), Energy Probe Research Foundation ("EP"), Pollution Prove ("PP"), School Energy Coalition ("SEC") and Vulnerable Energy Consumers Coalition. Pursuant to the OEB's Procedural Order No. 2, enclosed are the requisite two copies of THESL responses to these interrogatories.

The interrogatory responses are filed by issue. Please note that THESL did not receive any interrogatories on Issue 3.2. As per instructions provided to all parties from Martin Davies via email on September 10th, THESL has used the following acronyms for intervenors. Tab numbers for each issue and a corresponding schedule number to denote each intervenor are provided in the tables below.

Issue Number	Tab Number
1.1	6A
1.2	6B
1.3	6C
1.4	6D
2.1	6E
2.2	6F
2.3	6G
2.4	6H
3.1	6I
3.2	6J
4.1	6K
4.2	6L

Party Name	Acronym	Schedule Number
Ontario Energy Board Staff	Staff	01
Association of Major Power Consumers of Ontario	AMPCO	02
Building Owners and Managers Association Toronto	BOMA	03
Canadian Union of Public Employees (Local One)	CUPE	04
City of Toronto	City	05
Consumers Council of Canada	CCC	06
Energy Probe Research Foundation	EP	07
Ontario Power Generation Inc.	OPG	08
Pollution Probe Foundation	PP	09
School Energy Coalition	SEC	10
Vulnerable Energy Consumer Coalition	VECC	11

THESL has also arranged its interrogatory responses by intervenor. This version will be available by the next business day on THESL's Regulatory web page at: http://wcm.torontohydro.com/sites/electricsystem/Pages/2012IRM.aspx

Consumers Council of Canada interrogatory 19 requests certain information that THESL considers confidential. THESL requests that this information and the response to this interrogatory be treated confidentially as it includes terms of commercially sensitive, negotiated agreements with third parties in a competitive market. The disclosure of this information could negatively affect LDCs' future negotiations. THESL has provided a partial response to this interrogatory on a non-confidential basis, and provides the OEB with its complete response enclosed in an envelope marked "confidential", in accordance with the OEB's *Rules of Practice and Procedure* in its Practice Direction on Confidential Filings. THESL asks that the OEB limit circulation of this interrogatory response to counsel who sign the OEB's Declaration of Understanding. THESL also notes that should any party wish to cross-examine/or address this document in any other way during this proceeding, THESL requests that those proceedings be conducted *in camera*, and any submissions or other written material pertaining to these documents be filed in confidence, all in accordance with the Practice Direction.

For the evidentiary corrections (including the withdrawal of the Grid Solutions project as THESL advised the Board in its letter dated October 5, 2012) included in the enclosed interrogatories, THESL respectfully proposes to provide update-pages to the evidence along with the evidentiary update referred to in its letter of September 21, 2012.

Please do not hesitate to contact me if you have any questions.

Sincerely,

Per: **Amanda Klein**
Director, Regulatory Affairs
Toronto Hydro-Electric System Limited
regulatoryaffairs@torontohydro.com

:AK/RB/acc

cc: Fred Cass, Counsel for THESL
Intervenors of Record for EB-2012-0064

Amanda Klein
Director, Regulatory Affairs
Toronto Hydro-Electric System Limited
14 Carlton Street
Toronto, Ontario M5B 1K5

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Ms. Kirsten Walli
Board Secretary
Ontario Energy Board
PO Box 2319
2300 Yonge Street, 27th floor
Toronto, ON M4P 1E4

Dear Ms. Walli:

Re: Toronto Hydro-Electric System Limited ("THESL")
OEB File No. EB-2012-0064 (the "Application")

THESL writes in respect of the above-noted matter.

THESL advises the Ontario Energy Board ("OEB") and parties to this proceeding that it has concluded that the Grid Solutions project (Tab 4, Schedule B-22 of THESL's pre-filed evidence) is best considered within a discrete *Green Energy Act* plan which THESL intends to file at the earliest practicable opportunity. THESL is accordingly withdrawing this section of its evidence, and the relief associated with it, from the Application.

Yours truly,

Per: **Amanda Klein**
Director, Regulatory Affairs
Toronto Hydro-Electric System Limited
regulatoryaffairs@torontohydro.com

:AK/RB

cc: Fred D. Cass, Aird & Berlis LLP, Counsel for THESL, by electronic mail only
Intervenors of Record for EB-2012-0064 by electronic mail only

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES ON ISSUE 1.1

INTERROGATORY 1:

Reference(s): T3/S C1.1/p. 7 2012 IRM 3 Model and T3/S A/p.3

In the first reference THESL has provided a variable rate rider charge of $0.00008 for foregone revenues for the GS < 50 kW class.

In the second reference, which is THESL's current tariff sheet, a credit charge of the same amount is shown.

Please explain this apparent discrepancy.

RESPONSE:

THESL believes that the second reference should be Tab 3, Schedule A, page 2. The value shown in Tab 3, Schedule C1.1, page 7 should be a negative value. It was not used in any calculation in the Model. This rate rider expired on April 30, 2012.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES ON ISSUE 1.1

INTERROGATORY 2:

Reference(s): **T3/S C1.1 2012 IRM 3 Model /pp. 20-21**

Please reconcile the closing 2010 balance in account 1521 shown on p. 21 of the above reference with the closing balance for December 31, 2012 provided in THESL's RRR 2.1.1 filing and provide any necessary explanations.

Please include an explanation of the credit of $3,050,473 shown on page 20 of the above reference.

RESPONSE:

THESL's December 31, 2010 balance in account 1521 is $3,554,958. This value is the same as THESL provided in its RRR 2.1.1 filing, and is shown in the referenced exhibit under the column header "2.1.7 RRR".

Because many of the fields are locked in the Board's model, THESL needed to input an amount of $3,050,473 in the column titled "Other Adjustments during Q4 2010" to ensure that the final value produced by the model for clearance as a rate rider reflected the final balances remaining in this account. The amount of $3,050,473 represents the recoveries of the Special Purpose Charge during 2011.

A detailed reconciliation of this account showing the final amount for clearance is attached as Appendix A.

Account 1521 - Special Purpose Charge Reconciliation

Approved by OEB for recoveries	$	9,697,579.00
May 2010 to Dec 2010 recoveries	-	6,123,220.24
Carrying charges booked	-	19,400.78
Closing balances as of Dec 31, 2010		**3,554,957.98**
Jan 2011 to Dec 2011 recoveries	-	3,050,472.64
Carrying charges booked		67,502.09
Closing balances as of Dec 31, 2011		**571,987.43**
Interest from Jan 2012-April 2012		2,590.00
Total to be cleared	**$**	**574,577.43**
Total approved for recovery	**$**	**9,697,579.00**
Total collected incl carrying charges	-	9,125,591.57
Total Under recoveries to be collected		571,987.43
Carrying charges for Jan to April 2012		2,590.00
Total to be collected	**$**	**574,577.43**

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES ON ISSUE 1.1

INTERROGATORY 3:

Reference(s): **T3/S D/p. 3 2012 RTSR Workform**

A section of the above reference is reproduced below:

Rate Class	Unit	RTSR - Network	RTSR - Connection
Residential	kWh	$ 0.0070	$ 0.0051
Residential Urban	kWh	$ 0.0070	$ 0.0051
General Service Less Than 50 kW	kWh	$ 0.0068	$ 0.0046
General Service 50 to 999 kW	kW	$ 2.4351	$ 1.7630
General Service 1,000 to 4,999 kW	kW	$ 2.3527	$ 1.7613
Large Use	kW	$ 2.6820	$ 1.9567
Street Lighting	kW	$ 2.1658	$ 2.1022
Unmetered Scattered Load	kWh	$ 0.0043	$ 0.0032

On Sheet 3 of the RTSR Workform, THESL has provided the current Network and combined Line and Connection Retail Transmission Rate charges for each class. Board staff notes that the Retail Transmission Rate charges for some of its classes (e.g. GS 50 kW to 999 kW, Large Use, etc.) are billed on a per 30 day basis.

Please provide a description of the difference between how the per 30 day volumetric rate riders are applied to customers in these classes compared to customers in classes such as Residential.

RESPONSE:

For customers who are billed RTSR on a kWh (energy) basis (Residential, GS<50kW, and USL), customers are billed on the basis of the total measured kWh for the billing period. For customers who are billed RTSR on a kW (demand) basis (GS 50-999kW, GS 1000-4999kW, Large users and Streetlighting), the customers are billed on the basis of measured peak kW over a 30-day period. In both cases, this matches with how the rate is calculated.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES ON ISSUE 1.1

INTERROGATORY 4:

Reference(s): **T3/S D/p. 4 2012 RTSR Workform**

A section of the above referenced page is reproduced below:

	Rate Class	Unit	Non-Loss Adjusted Metered kWh	Non-Loss Adjusted Metered kW	Applicable Loss Factor
27	Residential	kWh	5,105,974,275	-	1.0376
28	Residential Urban	kWh	99,791,184	-	1.0376
29	General Service Less Than 50 kW	kWh	2,095,343,918	-	1.0376
30	General Service 50 to 999 kW	kW	10,189,051,346	26,712,248	
31	General Service 1,000 to 4,999 kW	kW	4,828,382,733	10,972,419	
32	Large Use	kW	2,263,227,585	5,267,224	
33	Street Lighting	kW	112,727,603	321,995	
34	Unmetered Scattered Load	kWh	52,097,299	-	1.0376

Board staff is unable to reconcile the metered kWh and metered kW data provided in the above with the values provided in THESL's RRR 2.1.5 filing for year-end December 31, 2010. Please provide a reconciliation and if any corrections are necessary, please state what they are.

RESPONSE:

THESL inadvertently input the loss adjusted kWh and billing kVA instead of kW for this schedule. A corrected version of the RTSR Workform, which includes this correction, is provided hereto as Appendix A.

Ontario Energy Board

RTSR WORK FORM FOR ELECTRICITY DISTRIBUTORS

Choose Your Utility:

Tillsonburg Hydro Inc.
Toronto Hydro-Electric System Limited

Application Type:	IRM3
OEB Application #:	EB-2011-0144
LDC Licence #:	ED-2002-0497
Last COS OEB Application #:	EB-201
Last COS Re-Basing Year:	2011

Application Contact Information

Name:	Anthony Lam
Title:	Economist
Phone Number:	416 542-2876
Email Address:	alam@torontohydro.com

Copyright

Ontario Energy Board

RTSR WORK FORM FOR ELECTRICITY DISTRIBUTORS

Toronto Hydro-Electric System Limited - EB-2011-0144 - IRM3

1. Info

2. Table of Contents

3. Rate Classes

4. RRR Data

5. UTRs and Sub-Transmission

6. Historical Wholesale

7. Current Wholesale

8. Forecast Wholesale

9. Adj Network to Current WS

10. Adj Conn. to Current WS

11. Adj Network to Forecast WS

12. Adj Conn. to Forecast WS

Ontario Energy Board

RTSR WORK FORM FOR ELECTRICITY DISTRIBUTORS

Toronto Hydro-Electric System Limited - EB-2011-0144 - IRM3

1. Select the appropriate rate classes that appear on your most recent Board-Approved Tariff of Rates and Charges.
2. Enter the RTS Network and Connection Rate as it appears on the Tariff of Rates and Charges

Rate Class	Unit	RTSR - Network	RTSR - Connection
Residential	kWh	$ 0.0070	$ 0.0051
Residential Urban	kWh	$ 0.0070	$ 0.0051
General Service Less Than 50 kW	kWh	$ 0.0068	$ 0.0046
General Service 50 to 999 kW	kW	$ 2.4351	$ 1.7630
General Service 1,000 to 4,999 kW	kW	$ 2.3527	$ 1.7613
Large Use	kW	$ 2.6820	$ 1.9567
Street Lighting	kW	$ 2.1658	$ 2.1022
Unmetered Scattered Load	kWh	$ 0.0043	$ 0.0032
Choose Rate Class			
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Ontario Energy Board

RTSR WORK FORM FOR ELECTRICITY DISTRIBUTORS

Toronto Hydro-Electric System Limited - EB-2011-0144 - IRM3

In the green shaded cells, enter the most recent reported RRR billing determinants. Please ensure that billing determinants are non-loss adjusted.

Rate Class	Unit	Non-Loss Adjusted Metered kWh	Non-Loss Adjusted Metered kW	Applicable Loss Factor	Load Factor	Loss Adjusted Billed kWh	Billed kW
Residential	**kWh**	4,920,946,680	-	1.0376		5,105,974,275	-
Residential Urban	**kWh**	96,175,004	-	1.0376		99,791,184	-
General Service Less Than 50 kW	**kWh**	2,019,413,953	-	1.0376		2,095,343,918	-
General Service 50 to 999 kW	**kW**	9,819,825,893	24,480,774		**54.98%**	9,819,825,893	24,480,774
General Service 1,000 to 4,999 kW	**kW**	4,653,414,353	10,000,560		**63.78%**	4,653,414,353	10,000,560
Large Use	**kW**	2,181,213,941	4,859,098		**61.53%**	2,181,213,941	4,859,098
Street Lighting	**kW**	108,642,640	321,995		**46.25%**	108,642,640	321,995
Unmetered Scattered Load	**kWh**	50,209,425	-	1.0376		52,097,299	-

Ontario Energy Board

RTSR WORK FORM FOR ELECTRICITY DISTRIBUTORS

Toronto Hydro-Electric System Limited - EB-2011-0144 - IRM3

Uniform Transmission Rates

Rate Description	Unit	Effective January 1, 2010 Rate	Effective January 1, 2011 Rate	Effective January 1, 2012 Rate
Network Service Rate	kW	$ 2.97	$ 3.22	$ 3.57
Line Connection Service Rate	kW	$ 0.73	$ 0.79	$ 0.80
Transformation Connection Service Rate	kW	$ 1.71	$ 1.77	$ 1.86

Hydro One Sub-Transmission Rates

Rate Description	Unit	Effective January 1, 2010 Rate	Effective January 1, 2011 Rate	Effective January 1, 2012 Rate
Network Service Rate	kW	$ 2.65	$ 2.65	$ 2.65
Line Connection Service Rate	kW	$ 0.64	$ 0.64	$ 0.64
Transformation Connection Service Rate	kW	$ 1.50	$ 1.50	$ 1.50
Both Line and Transformation Connection Service Rate	kW	$ 2.14	$ 2.14	$ 2.14

Hydro One Sub-Transmission Rate Rider 6A

Rate Description	Unit	Effective January 1, 2010 Rate	Effective January 1, 2011 Rate	Effective January 1, 2012 Rate
RSVA Transmission network – 4714 – which affects 1584	kW	$ 0.0470	$ 0.0470	$ 0.0470
RSVA Transmission connection – 4716 – which affects 1586	kW	-$ 0.0250	-$ 0.0250	-$ 0.0250
RSVA LV – 4750 – which affects 1550	kW	$ 0.0580	$ 0.0580	$ 0.0580
RARA 1 – 2252 – which affects 1590	kW	-$ 0.0750	-$ 0.0750	-$ 0.0750
Hydro One Sub-Transmission Rate Rider 6A	kW	$ 0.0050	$ 0.0050	$ 0.0050

		Historical 2010	Current 2011	Forecast 2012
Low Voltage Switchgear Credit	$	- 8,169,997	- 8,411,016	- 8,732,452

Ontario Energy Board

RTSR WORK FORM FOR ELECTRICITY DISTRIBUTORS

Toronto Hydro-Electric System Limited - EB-2011-0144 - IRM3

In the green shaded cells, enter billing detail for wholesale transmission for the same reporting period as the billing determinants on Sheet "4. RRR Data". For Hydro One Sub-transmission Rates, if you are charged a *combined* Line and Transformer connection rate, please ensure that both the line connection and transformer connection columns are completed.

IESO

Month	Network Units Billed	Network Rate	Network Amount	Line Connection Units Billed	Line Connection Rate	Line Connection Amount	Transformation Connection Units Billed	Transformation Connection Rate	Transformation Connection Amount	Total Line Amount
January	3,974,155	$2.97	$ 11,803,240	3,920,041	$0.73	$ 2,861,630	4,005,793	$1.71	$ 6,849,906	$ 9,711,536
February	3,872,348	$2.97	$ 11,500,874	3,818,005	$0.73	$ 2,787,144	3,906,487	$1.71	$ 6,680,093	$ 9,467,236
March	3,533,613	$2.97	$ 10,494,831	3,487,061	$0.73	$ 2,545,555	3,556,102	$1.71	$ 6,080,934	$ 8,626,489
April	3,225,020	$2.97	$ 9,578,309	3,270,132	$0.73	$ 2,387,196	3,330,873	$1.71	$ 5,695,793	$ 8,082,989
May	4,203,820	$2.97	$ 12,485,345	4,149,759	$0.73	$ 3,029,324	4,255,406	$1.71	$ 7,276,744	$ 10,306,068
June	4,025,876	$2.97	$ 11,956,852	3,946,823	$0.73	$ 2,881,181	4,046,593	$1.71	$ 6,919,674	$ 9,800,855
July	4,795,334	$2.97	$ 14,242,142	4,667,508	$0.73	$ 3,407,281	4,763,100	$1.71	$ 8,144,901	$ 11,552,182
August	4,541,370	$2.97	$ 13,487,869	4,457,988	$0.73	$ 3,254,331	4,552,896	$1.71	$ 7,785,452	$ 11,039,783
September	4,582,171	$2.97	$ 13,609,048	4,426,635	$0.73	$ 3,231,444	4,518,575	$1.71	$ 7,726,763	$ 10,958,207
October	3,254,324	$2.97	$ 9,665,342	3,300,173	$0.73	$ 2,409,126	3,382,379	$1.71	$ 5,783,868	$ 8,192,994
November	3,537,782	$2.97	$ 10,507,213	3,466,344	$0.73	$ 2,530,431	3,538,025	$1.71	$ 6,050,023	$ 8,580,454
December	4,013,769	$2.97	$ 11,920,894	3,877,690	$0.73	$ 2,830,714	3,960,416	$1.71	$ 6,772,311	$ 9,603,025
Total	47,559,582	$ 2.97	$ 141,251,959	46,788,159	$ 0.73	$ 34,155,356	47,816,645	$ 1.71	$ 81,766,463	$ 115,921,819

HYDRO ONE

Month	Network Units Billed	Network Rate	Network Amount	Line Connection Units Billed	Line Connection Rate	Line Connection Amount	Transformation Connection Units Billed	Transformation Connection Rate	Transformation Connection Amount	Total Line Amount
January		$0.00			$0.00			$0.00		$ -
February		$0.00			$0.00			$0.00		$ -
March		$0.00			$0.00			$0.00		$ -
April		$0.00			$0.00			$0.00		$ -
May		$0.00			$0.00			$0.00		$ -
June		$0.00			$0.00			$0.00		$ -
July		$0.00			$0.00			$0.00		$ -
August		$0.00			$0.00			$0.00		$ -
September		$0.00			$0.00			$0.00		$ -
October		$0.00			$0.00			$0.00		$ -
November		$0.00			$0.00			$0.00		$ -
December		$0.00			$0.00			$0.00		$ -
Total	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -

TOTAL

Month	Network Units Billed	Network Rate	Network Amount	Line Connection Units Billed	Line Connection Rate	Line Connection Amount	Transformation Connection Units Billed	Transformation Connection Rate	Transformation Connection Amount	Total Line Amount
January	3,974,155	$2.97	$ 11,803,240	3,920,041	$0.73	$ 2,861,630	4,005,793	$1.71	$ 6,849,906	$ 9,711,536
February	3,872,348	$2.97	$ 11,500,874	3,818,005	$0.73	$ 2,787,144	3,906,487	$1.71	$ 6,680,093	$ 9,467,236
March	3,533,613	$2.97	$ 10,494,831	3,487,061	$0.73	$ 2,545,555	3,556,102	$1.71	$ 6,080,934	$ 8,626,489
April	3,225,020	$2.97	$ 9,578,309	3,270,132	$0.73	$ 2,387,196	3,330,873	$1.71	$ 5,695,793	$ 8,082,989
May	4,203,820	$2.97	$ 12,485,345	4,149,759	$0.73	$ 3,029,324	4,255,406	$1.71	$ 7,276,744	$ 10,306,068
June	4,025,876	$2.97	$ 11,956,852	3,946,823	$0.73	$ 2,881,181	4,046,593	$1.71	$ 6,919,674	$ 9,800,855
July	4,795,334	$2.97	$ 14,242,142	4,667,508	$0.73	$ 3,407,281	4,763,100	$1.71	$ 8,144,901	$ 11,552,182
August	4,541,370	$2.97	$ 13,487,869	4,457,988	$0.73	$ 3,254,331	4,552,896	$1.71	$ 7,785,452	$ 11,039,783
September	4,582,171	$2.97	$ 13,609,048	4,426,635	$0.73	$ 3,231,444	4,518,575	$1.71	$ 7,726,763	$ 10,958,207
October	3,254,324	$2.97	$ 9,665,342	3,300,173	$0.73	$ 2,409,126	3,382,379	$1.71	$ 5,783,868	$ 8,192,994
November	3,537,782	$2.97	$ 10,507,213	3,466,344	$0.73	$ 2,530,431	3,538,025	$1.71	$ 6,050,023	$ 8,580,454
December	4,013,769	$2.97	$ 11,920,894	3,877,690	$0.73	$ 2,830,714	3,960,416	$1.71	$ 6,772,311	$ 9,603,025
Total	47,559,582	$ 2.97	$ 141,251,959	46,788,159	$ 0.73	$ 34,155,356	47,816,645	$ 1.71	$ 81,766,463	$ 115,921,819

Low Voltage Switchgear Credit	- 8,169,997
	$ 107,751,822

Ontario Energy Board

RTSR WORK FORM FOR ELECTRICITY DISTRIBUTORS

Toronto Hydro-Electric System Limited - EB-2011-0144 - IRM3

The purpose of this sheet is to calculate the expected billing when current 2011 Uniform Transmission Rates are applied against historical 2010 transmission units.

IESO

	Network			Line Connection			Transformation Connection			Total Line
Month	**Units Billed**	**Rate**	**Amount**	**Units Billed**	**Rate**	**Amount**	**Units Billed**	**Rate**	**Amount**	**Amount**
January	3,974,155	$ 3.2200	$ 12,796,779	3,920,041	$ 0.7900	$ 3,096,832	4,005,793	$ 1.7700	$ 7,090,254	$ 10,187,086
February	3,872,348	$ 3.2200	$ 12,468,961	3,818,005	$ 0.7900	$ 3,016,224	3,906,487	$ 1.7700	$ 6,914,482	$ 9,930,706
March	3,533,613	$ 3.2200	$ 11,378,234	3,487,061	$ 0.7900	$ 2,754,778	3,556,102	$ 1.7700	$ 6,294,301	$ 9,049,079
April	3,225,020	$ 3.2200	$ 10,384,564	3,270,132	$ 0.7900	$ 2,583,404	3,330,873	$ 1.7700	$ 5,895,645	$ 8,479,049
May	4,203,820	$ 3.2200	$ 13,536,300	4,149,759	$ 0.7900	$ 3,278,310	4,255,406	$ 1.7700	$ 7,532,069	$ 10,810,378
June	4,025,876	$ 3.2200	$ 12,963,321	3,946,823	$ 0.7900	$ 3,117,990	4,046,593	$ 1.7700	$ 7,162,470	$ 10,280,460
July	4,795,334	$ 3.2200	$ 15,440,975	4,667,508	$ 0.7900	$ 3,687,331	4,763,100	$ 1.7700	$ 8,430,687	$ 12,118,018
August	4,541,370	$ 3.2200	$ 14,623,211	4,457,988	$ 0.7900	$ 3,521,811	4,552,896	$ 1.7700	$ 8,058,626	$ 11,580,436
September	4,582,171	$ 3.2200	$ 14,754,591	4,426,635	$ 0.7900	$ 3,497,042	4,518,575	$ 1.7700	$ 7,997,878	$ 11,494,919
October	3,254,324	$ 3.2200	$ 10,478,923	3,300,173	$ 0.7900	$ 2,607,137	3,382,379	$ 1.7700	$ 5,986,811	$ 8,593,948
November	3,537,782	$ 3.2200	$ 11,391,658	3,466,344	$ 0.7900	$ 2,738,412	3,538,025	$ 1.7700	$ 6,262,304	$ 9,000,716
December	4,013,769	$ 3.2200	$ 12,924,336	3,877,690	$ 0.7900	$ 3,063,375	3,960,416	$ 1.7700	$ 7,009,936	$ 10,073,311
Total	47,559,582	$ 3.22	$ 153,141,854	46,788,159	$ 0.79	$ 36,962,646	47,816,645	$ 1.77	$ 84,635,462	$ 121,598,107

HYDRO ONE

	Network			Line Connection			Transformation Connection			Total Line
Month	**Units Billed**	**Rate**	**Amount**	**Units Billed**	**Rate**	**Amount**	**Units Billed**	**Rate**	**Amount**	**Amount**
January	-	$ 2.6970	$ -	-	$ 0.6150	$ -	-	$ 1.5000	$ -	$ -
February	-	$ 2.6970	$ -	-	$ 0.6150	$ -	-	$ 1.5000	$ -	$ -
March	-	$ 2.6970	$ -	-	$ 0.6150	$ -	-	$ 1.5000	$ -	$ -
April	-	$ 2.6970	$ -	-	$ 0.6150	$ -	-	$ 1.5000	$ -	$ -
May	-	$ 2.6970	$ -	-	$ 0.6150	$ -	-	$ 1.5000	$ -	$ -
June	-	$ 2.6970	$ -	-	$ 0.6150	$ -	-	$ 1.5000	$ -	$ -
July	-	$ 2.6970	$ -	-	$ 0.6150	$ -	-	$ 1.5000	$ -	$ -
August	-	$ 2.6970	$ -	-	$ 0.6150	$ -	-	$ 1.5000	$ -	$ -
September	-	$ 2.6970	$ -	-	$ 0.6150	$ -	-	$ 1.5000	$ -	$ -
October	-	$ 2.6970	$ -	-	$ 0.6150	$ -	-	$ 1.5000	$ -	$ -
November	-	$ 2.6970	$ -	-	$ 0.6150	$ -	-	$ 1.5000	$ -	$ -
December	-	$ 2.6970	$ -	-	$ 0.6150	$ -	-	$ 1.5000	$ -	$ -
Total	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -

TOTAL

	Network			Line Connection			Transformation Connection			Total Line
Month	**Units Billed**	**Rate**	**Amount**	**Units Billed**	**Rate**	**Amount**	**Units Billed**	**Rate**	**Amount**	**Amount**
January	3,974,155	$ 3.22	$ 12,796,779	3,920,041	$ 0.79	$ 3,096,832	4,005,793	$ 1.77	$ 7,090,254	$ 10,187,086
February	3,872,348	$ 3.22	$ 12,468,961	3,818,005	$ 0.79	$ 3,016,224	3,906,487	$ 1.77	$ 6,914,482	$ 9,930,706
March	3,533,613	$ 3.22	$ 11,378,234	3,487,061	$ 0.79	$ 2,754,778	3,556,102	$ 1.77	$ 6,294,301	$ 9,049,079
April	3,225,020	$ 3.22	$ 10,384,564	3,270,132	$ 0.79	$ 2,583,404	3,330,873	$ 1.77	$ 5,895,645	$ 8,479,049
May	4,203,820	$ 3.22	$ 13,536,300	4,149,759	$ 0.79	$ 3,278,310	4,255,406	$ 1.77	$ 7,532,069	$ 10,810,378
June	4,025,876	$ 3.22	$ 12,963,321	3,946,823	$ 0.79	$ 3,117,990	4,046,593	$ 1.77	$ 7,162,470	$ 10,280,460
July	4,795,334	$ 3.22	$ 15,440,975	4,667,508	$ 0.79	$ 3,687,331	4,763,100	$ 1.77	$ 8,430,687	$ 12,118,018
August	4,541,370	$ 3.22	$ 14,623,211	4,457,988	$ 0.79	$ 3,521,811	4,552,896	$ 1.77	$ 8,058,626	$ 11,580,436
September	4,582,171	$ 3.22	$ 14,754,591	4,426,635	$ 0.79	$ 3,497,042	4,518,575	$ 1.77	$ 7,997,878	$ 11,494,919
October	3,254,324	$ 3.22	$ 10,478,923	3,300,173	$ 0.79	$ 2,607,137	3,382,379	$ 1.77	$ 5,986,811	$ 8,593,948
November	3,537,782	$ 3.22	$ 11,391,658	3,466,344	$ 0.79	$ 2,738,412	3,538,025	$ 1.77	$ 6,262,304	$ 9,000,716
December	4,013,769	$ 3.22	$ 12,924,336	3,877,690	$ 0.79	$ 3,063,375	3,960,416	$ 1.77	$ 7,009,936	$ 10,073,311
Total	47,559,582	$ 3.22	$ 153,141,854	46,788,159	$ 0.79	$ 36,962,646	47,816,645	$ 1.77	$ 84,635,462	$ 121,598,107

Low Voltage Switchgear Credit	- 8,411,016
	$ 113,187,091

Ontario Energy Board

RTSR WORK FORM FOR ELECTRICITY DISTRIBUTORS

Toronto Hydro-Electric System Limited - EB-2011-0144 - IRM3

The purpose of this sheet is to calculate the expected billing when forecasted 2012 Uniform Transmission Rates are applied against historical 2010 transmission units.

IESO

Month	Network Units Billed	Network Rate	Network Amount	Line Connection Units Billed	Line Connection Rate	Line Connection Amount	Transformation Connection Units Billed	Transformation Connection Rate	Transformation Connection Amount	Total Line Amount
January	3,974,155	$ 3.5700	$ 14,187,733	3,920,041	$ 0.8000	$ 3,136,033	4,005,793	$ 1.8600	$ 7,450,775	$ 10,586,808
February	3,872,348	$ 3.5700	$ 13,824,282	3,818,005	$ 0.8000	$ 3,054,404	3,906,487	$ 1.8600	$ 7,266,066	$ 10,320,470
March	3,533,613	$ 3.5700	$ 12,614,998	3,487,061	$ 0.8000	$ 2,789,649	3,556,102	$ 1.8600	$ 6,614,350	$ 9,403,999
April	3,225,020	$ 3.5700	$ 11,513,321	3,270,132	$ 0.8000	$ 2,616,106	3,330,873	$ 1.8600	$ 6,195,424	$ 8,811,529
May	4,203,820	$ 3.5700	$ 15,007,637	4,149,759	$ 0.8000	$ 3,319,807	4,255,406	$ 1.8600	$ 7,915,055	$ 11,234,862
June	4,025,876	$ 3.5700	$ 14,372,377	3,946,823	$ 0.8000	$ 3,157,458	4,046,593	$ 1.8600	$ 7,526,663	$ 10,684,121
July	4,795,334	$ 3.5700	$ 17,119,342	4,667,508	$ 0.8000	$ 3,734,006	4,763,100	$ 1.8600	$ 8,859,366	$ 12,593,372
August	4,541,370	$ 3.5700	$ 16,212,691	4,457,988	$ 0.8000	$ 3,566,390	4,552,896	$ 1.8600	$ 8,468,387	$ 12,034,777
September	4,582,171	$ 3.5700	$ 16,358,350	4,426,635	$ 0.8000	$ 3,541,308	4,518,575	$ 1.8600	$ 8,404,550	$ 11,945,858
October	3,254,324	$ 3.5700	$ 11,617,937	3,300,173	$ 0.8000	$ 2,640,138	3,382,379	$ 1.8600	$ 6,291,225	$ 8,931,363
November	3,537,782	$ 3.5700	$ 12,629,882	3,466,344	$ 0.8000	$ 2,773,075	3,538,025	$ 1.8600	$ 6,580,727	$ 9,353,802
December	4,013,769	$ 3.5700	$ 14,329,155	3,877,690	$ 0.8000	$ 3,102,152	3,960,416	$ 1.8600	$ 7,366,374	$ 10,468,526
Total	47,559,582	$ 3.57	$ 169,787,708	46,788,159	$ 0.80	$ 37,430,527	47,816,645	$ 1.86	$ 88,938,960	$ 126,369,487

HYDRO ONE

Month	Network Units Billed	Network Rate	Network Amount	Line Connection Units Billed	Line Connection Rate	Line Connection Amount	Transformation Connection Units Billed	Transformation Connection Rate	Transformation Connection Amount	Total Line Amount
January	-	$ 2.6970	$ -	-	$ 0.6150	$ -	-	$ 1.5000	$ -	$ -
February	-	$ 2.6970	$ -	-	$ 0.6150	$ -	-	$ 1.5000	$ -	$ -
March	-	$ 2.6970	$ -	-	$ 0.6150	$ -	-	$ 1.5000	$ -	$ -
April	-	$ 2.6970	$ -	-	$ 0.6150	$ -	-	$ 1.5000	$ -	$ -
May	-	$ 2.6970	$ -	-	$ 0.6150	$ -	-	$ 1.5000	$ -	$ -
June	-	$ 2.6970	$ -	-	$ 0.6150	$ -	-	$ 1.5000	$ -	$ -
July	-	$ 2.6970	$ -	-	$ 0.6150	$ -	-	$ 1.5000	$ -	$ -
August	-	$ 2.6970	$ -	-	$ 0.6150	$ -	-	$ 1.5000	$ -	$ -
September	-	$ 2.6970	$ -	-	$ 0.6150	$ -	-	$ 1.5000	$ -	$ -
October	-	$ 2.6970	$ -	-	$ 0.6150	$ -	-	$ 1.5000	$ -	$ -
November	-	$ 2.6970	$ -	-	$ 0.6150	$ -	-	$ 1.5000	$ -	$ -
December	-	$ 2.6970	$ -	-	$ 0.6150	$ -	-	$ 1.5000	$ -	$ -
Total	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -

TOTAL

Month	Network Units Billed	Network Rate	Network Amount	Line Connection Units Billed	Line Connection Rate	Line Connection Amount	Transformation Connection Units Billed	Transformation Connection Rate	Transformation Connection Amount	Total Line Amount
January	3,974,155	$ 3.57	$ 14,187,733	3,920,041	$ 0.80	$ 3,136,033	4,005,793	$ 1.86	$ 7,450,775	$ 10,586,808
February	3,872,348	$ 3.57	$ 13,824,282	3,818,005	$ 0.80	$ 3,054,404	3,906,487	$ 1.86	$ 7,266,066	$ 10,320,470
March	3,533,613	$ 3.57	$ 12,614,998	3,487,061	$ 0.80	$ 2,789,649	3,556,102	$ 1.86	$ 6,614,350	$ 9,403,999
April	3,225,020	$ 3.57	$ 11,513,321	3,270,132	$ 0.80	$ 2,616,106	3,330,873	$ 1.86	$ 6,195,424	$ 8,811,529
May	4,203,820	$ 3.57	$ 15,007,637	4,149,759	$ 0.80	$ 3,319,807	4,255,406	$ 1.86	$ 7,915,055	$ 11,234,862
June	4,025,876	$ 3.57	$ 14,372,377	3,946,823	$ 0.80	$ 3,157,458	4,046,593	$ 1.86	$ 7,526,663	$ 10,684,121
July	4,795,334	$ 3.57	$ 17,119,342	4,667,508	$ 0.80	$ 3,734,006	4,763,100	$ 1.86	$ 8,859,366	$ 12,593,372
August	4,541,370	$ 3.57	$ 16,212,691	4,457,988	$ 0.80	$ 3,566,390	4,552,896	$ 1.86	$ 8,468,387	$ 12,034,777
September	4,582,171	$ 3.57	$ 16,358,350	4,426,635	$ 0.80	$ 3,541,308	4,518,575	$ 1.86	$ 8,404,550	$ 11,945,858
October	3,254,324	$ 3.57	$ 11,617,937	3,300,173	$ 0.80	$ 2,640,138	3,382,379	$ 1.86	$ 6,291,225	$ 8,931,363
November	3,537,782	$ 3.57	$ 12,629,882	3,466,344	$ 0.80	$ 2,773,075	3,538,025	$ 1.86	$ 6,580,727	$ 9,353,802
December	4,013,769	$ 3.57	$ 14,329,155	3,877,690	$ 0.80	$ 3,102,152	3,960,416	$ 1.86	$ 7,366,374	$ 10,468,526
Total	47,559,582	$ 3.57	$ 169,787,708	46,788,159	$ 0.80	$ 37,430,527	47,816,645	$ 1.86	$ 88,938,960	$ 126,369,487

Low Voltage Switchgear Credit	- 8,732,452
	$ 117,637,035

Ontario Energy Board

RTSR WORK FORM FOR ELECTRICITY DISTRIBUTORS

Toronto Hydro-Electric System Limited - EB-2011-0144 - IRM3

The purpose of this sheet is to re-align the current RTS Network Rates to recover current wholesale network costs.

Rate Class	Unit	Current RTSR - Network	Loss Adjusted Billed kWh	Loss Adjusted Billed kW	Billed Amount	Billed Amount %	Current Wholesale Billing	Adjusted RTSR Network
Residential	kWh	$ 0.0070	5,105,974,275	-	$ 35,894,999	24.3%	$ 37,157,444	$ 0.0073
Residential Urban	kWh	$ 0.0070	99,791,184	-	$ 701,532	0.5%	$ 726,205	$ 0.0073
General Service Less Than 50 kW	kWh	$ 0.0068	2,095,343,918	-	$ 14,248,339	9.6%	$ 14,749,460	$ 0.0070
General Service 50 to 999 kW	kW	$ 2.4351	9,819,825,893	24,480,774	$ 59,613,132	40.3%	$ 61,709,756	$ 2.5207
General Service 1,000 to 4,999 kW	kW	$ 2.3527	4,653,414,353	10,000,560	$ 23,528,319	15.9%	$ 24,355,821	$ 2.4354
Large Use	kW	$ 2.6820	2,181,213,941	4,859,098	$ 13,032,101	8.8%	$ 13,490,446	$ 2.7763
Street Lighting	kW	$ 2.1658	108,642,640	321,995	$ 697,376	0.5%	$ 721,903	$ 2.2420
Unmetered Scattered Load	kWh	$ 0.0043	52,097,299	-	$ 222,976	0.2%	$ 230,819	$ 0.0044
					$ 147,938,773			

Ontario Energy Board

RTSR WORK FORM FOR ELECTRICITY DISTRIBUTORS

Toronto Hydro-Electric System Limited - EB-2011-0144 - IRM3

The purpose of this sheet is to re-align the current RTS Connection Rates to recover current wholesale connection costs.

Rate Class	Unit	Current RTSR - Connection	Loss Adjusted Billed kWh	Loss Adjusted Billed kW	Billed Amount	Billed Amount %	Current Wholesale Billing	Adjusted RTSR Connection
Residential	kWh	$ 0.0051	5,105,974,275	-	$ 26,193,648	24.4%	$ 27,570,630	$ 0.0054
Residential Urban	kWh	$ 0.0051	99,791,184	-	$ 511,929	0.5%	$ 538,841	$ 0.0054
General Service Less Than 50 kW	kWh	$ 0.0046	2,095,343,918	-	$ 9,701,442	9.0%	$ 10,211,440	$ 0.0049
General Service 50 to 999 kW	kW	$ 1.7630	9,819,825,893	24,480,774	$ 43,159,604	40.1%	$ 45,428,474	$ 1.8557
General Service 1,000 to 4,999 kW	kW	$ 1.7613	4,653,414,353	10,000,560	$ 17,613,987	16.4%	$ 18,539,942	$ 1.8539
Large Use	kW	$ 1.9567	2,181,213,941	4,859,098	$ 9,507,797	8.8%	$ 10,007,615	$ 2.0596
Street Lighting	kW	$ 2.1022	108,642,640	321,995	$ 676,897	0.6%	$ 712,481	$ 2.2127
Unmetered Scattered Load	kWh	$ 0.0032	52,097,299	-	$ 168,795	0.2%	$ 177,669	$ 0.0034
					$ 107,534,099			

Ontario Energy Board

RTSR WORK FORM FOR ELECTRICITY DISTRIBUTORS

Toronto Hydro-Electric System Limited - EB-2011-0144 - IRM3

The purpose of this sheet is to update the re-align RTS Network Rates to recover forecast wholesale network costs.

Rate Class	Unit	Adjusted RTSR - Network	Loss Adjusted Billed kWh	Loss Adjusted Billed kW	Billed Amount	Billed Amount %	Forecast Wholesale Billing	Proposed RTSR Network
Residential	kWh	$ 0.0073	5,105,974,275	-	$ 37,157,444	24.3%	$ 41,196,297	$ 0.0081
Residential Urban	kWh	$ 0.0073	99,791,184	-	$ 726,205	0.5%	$ 805,141	$ 0.0081
General Service Less Than 50 kW	kWh	$ 0.0070	2,095,343,918	-	$ 14,749,460	9.6%	$ 16,352,662	$ 0.0078
General Service 50 to 999 kW	kW	$ 2.5207	9,819,825,893	24,480,774	$ 61,709,756	40.3%	$ 68,417,338	$ 2.7947
General Service 1,000 to 4,999 kW	kW	$ 2.4354	4,653,414,353	10,000,560	$ 24,355,821	15.9%	$ 27,003,193	$ 2.7002
Large Use	kW	$ 2.7763	2,181,213,941	4,859,098	$ 13,490,446	8.8%	$ 14,956,799	$ 3.0781
Street Lighting	kW	$ 2.2420	108,642,640	321,995	$ 721,903	0.5%	$ 800,371	$ 2.4857
Unmetered Scattered Load	kWh	$ 0.0044	52,097,299	-	$ 230,819	0.2%	$ 255,908	$ 0.0049
					$ 153,141,854			

Ontario Energy Board

RTSR WORK FORM FOR ELECTRICITY DISTRIBUTORS

Toronto Hydro-Electric System Limited - EB-2011-0144 - IRM3

The purpose of this sheet is to update the re-aligned RTS Connection Rates to recover forecast wholesale connection costs.

Rate Class	Unit	Adjusted RTSR - Connection	Loss Adjusted Billed kWh	Loss Adjusted Billed kW	Billed Amount	Billed Amount %	Forecast Wholesale Billing	Proposed RTSR Connection
Residential	kWh	$ 0.0054	5,105,974,275	-	$ 27,570,630	24.4%	$ 28,654,567	$ 0.0056
Residential Urban	kWh	$ 0.0054	99,791,184	-	$ 538,841	0.5%	$ 560,025	$ 0.0056
General Service Less Than 50 kW	kWh	$ 0.0049	2,095,343,918	-	$ 10,211,440	9.0%	$ 10,612,902	$ 0.0051
General Service 50 to 999 kW	kW	$ 1.8557	9,819,825,893	24,480,774	$ 45,428,474	40.1%	$ 47,214,492	$ 1.9286
General Service 1,000 to 4,999 kW	kW	$ 1.8539	4,653,414,353	10,000,560	$ 18,539,942	16.4%	$ 19,268,839	$ 1.9268
Large Use	kW	$ 2.0596	2,181,213,941	4,859,098	$ 10,007,615	8.8%	$ 10,401,064	$ 2.1405
Street Lighting	kW	$ 2.2127	108,642,640	321,995	$ 712,481	0.6%	$ 740,492	$ 2.2997
Unmetered Scattered Load	kWh	$ 0.0034	52,097,299	-	$ 177,669	0.2%	$ 184,654	$ 0.0035
					$ 113,187,091			

Ontario Energy Board

RTSR WORK FORM FOR ELECTRICITY DISTRIBUTORS

Toronto Hydro-Electric System Limited - EB-2011-0144 - IRM3

For Cost of Service Applicants, please enter the following Proposed RTS rates into your rates model.

For IRM applicants, please enter these rates into the 2012 Rate Generator.

Rate Class	Unit	Proposed RTSR Network	Proposed RTSR Connection
Residential	kWh	$ 0.0081	$ 0.0056
Residential Urban	kWh	$ 0.0081	$ 0.0056
General Service Less Than 50 kW	kWh	$ 0.0078	$ 0.0051
General Service 50 to 999 kW	kW	$ 2.7947	$ 1.9286
General Service 1,000 to 4,999 kW	kW	$ 2.7002	$ 1.9268
Large Use	kW	$ 3.0781	$ 2.1405
Street Lighting	kW	$ 2.4857	$ 2.2997
Unmetered Scattered Load	kWh	$ 0.0049	$ 0.0035

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES ON ISSUE 1.1

INTERROGATORY 5:

Reference(s): T3/S D/p. 5 2012 RTSR Workform

A section of the above reference is reproduced below:

Hydro One Sub-Transmission Rate Rider 6A	Unit	Effective January 1, 2010	Effective January 1, 2011	Effective January 1, 2012
Rate Description		Rate	Rate	Rate
RSVA Transmission network – 4714 – which affects 1584	kW	$ 0.0470	$ 0.0470	$ 0.0470
RSVA Transmission connection – 4716 – which affects 158	kW	-$ 0.0250	-$ 0.0250	-$ 0.0250
RSVA LV – 4750 – which affects 1550	kW	$ 0.0580	$ 0.0580	$ 0.0580
RARA 1 – 2252 – which affects 1590	kW	-$ 0.0750	-$ 0.0750	-$ 0.0750
Hydro One Sub-Transmission Rate Rider 6A	kW	$ 0.0050	$ 0.0050	$ 0.0050
		Historical 2010	Current 2011	Forecast 2012
Low Voltage Switchgear Credit	$	- 8,169,997	- 8,411,016	8,732,452

Board staff notes that the Hydro One Sub-Transmission Rate Rider 6A included in the above table expired on January 31, 2011.

a) **Please provide an updated version of the RTSR model that reflects the expiry date of Rate Rider 6A.**

RESPONSE:

a) THESL has used the OEB's RTSR model to develop the RTSR proposed rates. The OEB's model only allows inputs or changes in cells which are highlighted in green. Values in other cells are either calculated by, or provided with the model, and are not editable by THESL. THESL is therefore unable to change the values in these cells of

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES ON ISSUE 1.1

the model. THESL notes that since it does not incur any Hydro One sub-transmission charges, changing these values in the model will not impact the calculated proposed RTSRs.

b) Please provide supporting evidence for the Low Voltage Switchgear Credits shown in the above table, including an explanation as to why the switchgear credits are negative in 2010 and 2011 and positive in 2012.

RESPONSE:

b) THESL inadvertently input the 2012 Low Voltage Switchgear Credit with the wrong sign. A corrected version of the RTSR Workform will be provided.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES ON ISSUE 1.1

INTERROGATORY 6:

Reference(s): T3/S E1/p. 3 2012 IRM 3 Tax Savings Workform

Please confirm that the number of connections provided in the above reference is correct and provide supporting evidence for them.

RESPONSE:

The billing determinants (number of customer connections and number of customers) shown in the referenced document are the 2011 values which the Board approved in EB-2010-0142, and are therefore correct. The said information is highlighted in Appendix A to this response which was filed in that proceeding.

Table 1: Customers by Class

	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8	Col. 9	Col. 10	Col. 11	Col. 12	Col. 13	Col. 14
1														
2			2005 Actual	2006 Board Approved	2006 Actual	2007 Board Approved	2007 Actual	2008 Board Approved	2008 Actual	2009 Board Approved	2009 Actual	2010 Board Approved	2010 Bridge Year	2011 Test Year
3	Residential	Customers	594,499	597,210	597,435	n/a	599,802	603,384	604,082	611,808	609,439	614,841	615,975	623,406
4	GS <50 kW	Customers	66,668	66,505	67,004	n/a	66,617	66,246	66,311	66,191	66,074	65,747	65,877	65,792
5	GS 50-999 kW	Customers	11,214	11,232	11,397	n/a	11,440	11,612	12,066	11,719	12,231	12,276	12,833	13,067
6	GS 1000-4999 kW	Customers	507	511	521	n/a	517	524	520	530	515	517	514	514
7	Large Use	Customers	47	47	48	n/a	49	49	49	49	47	47	47	47
8	Street Lighting	Connections	159,861	159,861	159,861	n/a	161,876	162,046	162,120	162,450	162,219	162,353	162,640	**162,777**
9	Unmetered Scattered Load	Customers	1,296	1,438	1,240	n/a	902	1,135	1,115	1,135	1,093	1,124	1,130	**1,130**
10		Connections	13,741	13,408	19,811	n/a	19,335	19,907	21,371	19,907	21,394	21,782	21,729	**21,729**
11	Total	Customers	674,231	676,943	677,645	n/a	679,327	682,950	684,143	691,432	689,399	694,551	696,377	703,956
12		Connections	173,602	173,269	179,672	n/a	181,211	181,953	183,491	182,357	183,613	184,136	184,369	184,506
13														
14	Notes													
15	1. Customer/Connection values are mid-year													

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES ON ISSUE 1.1

INTERROGATORY 7:

Reference(s): **T3/S E1/p. 5 2012 IRM 3 Tax Savings Workform and EB-2010-0142 Draft Rate Order App. A/p.5**

In the first reference, THESL has provided a tax rate of 28.14%. The second provided a Board approved tax rate of 28.25%.

Please provide an explanation for the use of different tax rates.

RESPONSE:

The OEB-approved tax rate of 28.25% in the second reference was the statutory tax rate that THESL used for calculating its approved 2011 PILs tax allowance. The tax rate of 28.14% was needed to arrive at the total approved PILs (Grossed-up Tax Amount) of $11,791,223 for 2011. By applying the effective tax rate, $11,791,223 in the first reference agrees to the total OEB-approved tax allowance in the second reference.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES ON ISSUE 1.1

INTERROGATORY 8:

Reference(s): T4/S E1.1/p. 6 Incremental Capital Workform

On Sheet B1.4 "Re-Based Rev Req", THESL has provided the revenue requirement parameters from its last cost of service application (EB-2010-0142).

a) Please file a copy of the page or pages from the relevant Revenue Requirement Work Form from which these numbers were derived. Please clearly identify the date on which this material was originally filed.

RESPONSE:

a) Attached is Appendix A, the Revenue Requirement Work Form filed on July 14 (and again on July 19), 2011 in EB-2010-0142, reflecting the Board's decision with respect to 2011 revenue requirement and the consequences therein.

b) Please confirm that the entries on Sheet B1.4 of the present application are in conformity with the material provided in part a, or if there are any differences, please provide an explanation.

RESPONSE:

b) All of the entries in Sheet B1.4 of the referenced evidence are in conformity with the Revenue Requirement Work Form filed July 22, 2011, except for a typographical error in the value shown for OM&A expenses. The value in B1.4 should be 231,214,224 (instead of 231,014,224, a difference of 200,000). This correction has no implications for the calculated ICM rate riders.

REVENUE REQUIREMENT WORK FORM

Name of LDC: Toronto Hydro-Electric System Limited (1)

File Number: EB-2010-0142

Rate Year: 2011

Version: 2.11

Table of Content

Sheet	Name
A	Data Input Sheet
1	Rate Base
2	Utility Income
3	Taxes/PILS
4	Capitalization/Cost of Capital
5	Revenue Sufficiency/Deficiency
6	Revenue Requirement
7A	Bill Impacts -Residential
7B	Bill Impacts - GS < 50 kW

Notes:
(1) Pale green cells represent inputs
(2) Pale yellow cells represent drop=down lists
(3) ***Please note that this model uses MACROS. Before starting, please ensure that macros have been enabled.***
(4) ***Completed versions of the Revenue Requirement Work Form are required to be filed in working Microsoft Excel format.***

REVENUE REQUIREMENT WORK FORM

Version: 2.11

Ontario

Name of LDC: Toronto Hydro-Electric System Limite
File Number: EB-2010-0142
Rate Year: 2011

		Data Input							(1)
		Initial Application		Adjustments	Settlement Agreement	(7)	Adjustments	Per Board Decision	
1	**Rate Base**								
	Gross Fixed Assets (average)	$4,404,200,772		($46,167,599)	$4,358,033,172		$ -	$4,358,033,172	
	Accumulated Depreciation (average)	($2,376,268,969)	(5)	$19,723,763	-$2,356,545,206		$ -	($2,356,545,206)	
	Allowance for Working Capital:								
	Controllable Expenses	$226,817,269		$10,999,337	$ 237,816,606		$200,000	$238,016,606	
	Cost of Power	$2,242,116,161		($175,847,874)	$2,066,268,287			$2,066,268,287	
	Working Capital Rate (%)	12.90%			12.88%			12.88%	
2	**Utility Income**								
	Operating Revenues:								
	Distribution Revenue at Current Rates	$518,135,903		$0	$518,135,903		$0	$518,135,903	
	Distribution Revenue at Proposed Rates	$578,428,862		($56,587,577)	$521,841,285		$203,059	$522,044,344	
	Other Revenue:								
	Specific Service Charges	$7,580,526		$0	$7,580,526		($0)	$7,580,526	
	Late Payment Charges	$4,900,000		$0	$4,900,000		($0)	$4,900,000	
	Other Distribution Revenue	$7,240,556		$0	$7,240,556		$0	$7,240,556	
	Other Income and Deductions	$16,382		$6,283,618	$6,300,000		$0	$6,300,000	
	Operating Expenses:								
	OM+A Expenses	$220,014,886		$10,999,338	$ 231,014,224		$200,000	$231,214,224	
	Depreciation/Amortization	$178,263,303		($39,447,522)	$ 138,815,781			$138,815,781	
	Property taxes	$6,802,382		$ -	$ 6,802,382			$6,802,382	
	Capital taxes								
	Other expenses								
3	**Taxes/PILs**								
	Taxable Income:								
	Adjustments required to arrive at taxable income	($17,273,077)	(3)		($54,417,922)			($54,416,942)	
	Utility Income Taxes and Rates:								
	Income taxes (not grossed up)	$20,189,870			$8,459,584			$8,460,203	
	Income taxes (grossed up)	$28,139,192			$11,790,361			$11,791,223	
	Capital Taxes		(6)			(6)			(6)
	Federal tax (%)	16.50%			16.50%			16.50%	
	Provincial tax (%)	11.75%			11.75%			11.75%	
	Income Tax Credits	($1,046,240)			($1,046,240)			($1,046,240)	
4	**Capitalization/Cost of Capital**								
	Capital Structure:								
	Long-term debt Capitalization Ratio (%)	56.0%			56.0%			56.0%	
	Short-term debt Capitalization Ratio (%)	4.0%	(2)		4.0%	(2)		4.0%	(2)
	Common Equity Capitalization Ratio (%)	40.0%			40.0%			40.0%	
	Prefered Shares Capitalization Ratio (%)								
		100.0%			100.0%			100.0%	
	Cost of Capital								
	Long-term debt Cost Rate (%)	5.37%			5.37%			5.37%	
	Short-term debt Cost Rate (%)	2.07%			2.46%			2.46%	
	Common Equity Cost Rate (%)	9.85%			9.58%			9.58%	
	Prefered Shares Cost Rate (%)								

Notes:

(Rate Base through Revenue Requirement), except for Notes that the utility may wish to use to support the data. Notes should be put on the applicable pages to explain numbers shown.

(1) All inputs are in dollars ($) except where inputs are individually identified as percentages (%)
(2) 4.0% unless an Applicant has proposed or been approved for another amount.
(3) Net of addbacks and deductions to arrive at taxable income.
(4) Average of Gross Fixed Assets at beginning and end of the Test Year
(5) Average of Accumulated Depreciation at the beginning and end of the Test Year. Enter as a negative amount.
(6) Not applicable as of July 1, 2010
(7) Select option from drop-down list by clicking on cell M10. This columnallows for the application update reflecting the end of discovery or Argument-in-Chief. Also, the outsome of any Settlement Process can be reflected.

REVENUE REQUIREMENT WORK FORM

Version: 2.11

Ontario

Name of LDC: Toronto Hydro-Electric System Limited
File Number: EB-2010-0142
Rate Year: 2011

Rate Base

Line No.	Particulars		Initial Application	Adjustments	Settlement Agreement	Adjustments	Per Board Decision
1	Gross Fixed Assets (average)	(3)	$4,404,200,772	($46,167,599)	$4,358,033,172	$ -	$4,358,033,172
2	Accumulated Depreciation (average)	(3)	($2,376,268,969)	$19,723,763	($2,356,545,206)	$ -	($2,356,545,206)
3	Net Fixed Assets (average)	(3)	$2,027,931,803	($26,443,836)	$2,001,487,967	$ -	$2,001,487,967
4	Allowance for Working Capital	(1)	$318,391,990	($21,684,337)	$296,707,652	$31,662	$296,739,314
5	**Total Rate Base**		$2,346,323,793	($48,128,174)	$2,298,195,619	$31,662	$2,298,227,281

	(1) Allowance for Working Capital - Derivation							
6	Controllable Expenses		$226,817,269	$10,999,337		$237,816,606	$200,000	$238,016,606
7	Cost of Power		$2,242,116,161	###########		$2,066,268,287	$ -	$2,066,268,287
8	Working Capital Base		$2,468,933,430	###########		$2,304,084,893	$200,000	$2,304,284,893
9	Working Capital Rate %	(2)	12.90%	-0.02%	a	12.88%	0.00%	12.88%
10	Working Capital Allowance		$318,391,990	($21,684,337)		$296,707,652	$31,662	$296,739,314

Notes

(2) Generally 15%. Some distributors may have a unique rate due as a result of a lead-lag study.
(3) Average of opening and closing balances for the year.

REVENUE REQUIREMENT WORK FORM

Version: 2.11

Name of LDC: Toronto Hydro-Electric System Limited
File Number: EB-2010-0142
Rate Year: 2011

Ontario

Utility income

Line No.	Particulars		Initial Application	Adjustments	Settlement Agreement	Adjustments	Per Board Decision
	Operating Revenues:						
1	Distribution Revenue (at Proposed Rates)		$578,428,862	($56,587,577)	$521,841,285	$203,059	$522,044,344
2	Other Revenue	(1)	$19,737,464	($45,758,546)	$26,021,082	$0	$26,021,082
3	Total Operating Revenues		$598,166,326	($102,346,123)	$547,862,367	$203,059	$548,065,426
	Operating Expenses:						
4	OM+A Expenses		$220,014,886	$10,999,338	$231,014,224	$200,000	$231,214,224
5	Depreciation/Amortization		$178,263,303	($39,447,522)	$138,815,781	$ -	$138,815,781
6	Property taxes		$6,802,382	$ -	$6,802,382	$ -	$6,802,382
7	Capital taxes		$ -	$ -	$ -	$ -	$ -
8	Other expense		$ -	$ -		$ -	
9	Subtotal (lines 4 to 8)		$405,080,571	($28,448,184)	$376,632,387	$200,000	$376,832,387
10	Deemed Interest Expense		$72,501,405	($1,128,642)	$71,372,763	$983	$71,373,746
11	Total Expenses (lines 9 to 10)		$477,581,977	($29,576,827)	$448,005,150	$200,983	$448,206,133
12	**Utility income before income taxes**		$120,584,349	($72,769,296)	$99,857,217	$2,076	$99,859,293
13	Income taxes (grossed-up)		$28,139,192	($16,348,831)	$11,790,361	$863	$11,791,223
14	**Utility net income**		$92,445,157	($56,420,465)	$88,066,856	$1,213	$88,068,069

Notes

(1)

	Initial Application	Adjustments	Settlement Agreement	Adjustments	Per Board Decision
Other Revenues / Revenue Offsets					
Specific Service Charges	$7,580,526	$ -	$7,580,526	($0)	$7,580,526
Late Payment Charges	$4,900,000	$ -	$4,900,000	($0)	$4,900,000
Other Distribution Revenue	$7,240,556	$ -	$7,240,556	$0	$7,240,556
Other Income and Deductions	$16,382	$6,283,618	$6,300,000	$ -	$6,300,000
Total Revenue Offsets	$19,737,464	$6,283,618	$26,021,082	$0	$26,021,082

REVENUE REQUIREMENT WORK FORM

Version: 2.11

Ontario

Name of LDC: Toronto Hydro-Electric System Limited
File Number: EB-2010-0142
Rate Year: 2011

Taxes/PILs

Line No.	Particulars	Application		Settlement Agreement		Per Board Decision	
	Determination of Taxable Income						
1	Utility net income before taxes	$92,445,157		$88,066,856		$88,068,069	
2	Adjustments required to arrive at taxable utility income	($17,273,077)		($54,417,922)		($54,416,942)	
3	Taxable income	$75,172,080		$33,648,934		$33,651,127	
	Calculation of Utility income Taxes						
4	Income taxes	$20,189,870		$8,459,584		$8,460,203	
5	Capital taxes	$ -	(1)	$ -	(1)	$ -	(1)
6	Total taxes	$20,189,870		$8,459,584		$8,460,203	
7	Gross-up of Income Taxes	$7,949,322		$3,330,777		$3,331,021	
8	Grossed-up Income Taxes	$28,139,192		$11,790,361		$11,791,223	
9	PILs / tax Allowance (Grossed-up Income taxes + Capital taxes)	$28,139,192		$11,790,361		$11,791,223	
10	Other tax Credits	($1,046,240)		($1,046,240)		($1,046,240)	
	Tax Rates						
11	Federal tax (%)	16.50%		16.50%		16.50%	
12	Provincial tax (%)	11.75%		11.75%		11.75%	
13	Total tax rate (%)	28.25%		28.25%		28.25%	

Notes

(1) Capital Taxes not applicable after July 1, 2010 (i.e. for 2011 and later test years)

Ontario

REVENUE REQUIREMENT WORK FORM

Version: 2.11

Name of LDC: Toronto Hydro-Electric System Limited
File Number: EB-2010-0142
Rate Year: 2011

Capitalization/Cost of Capital

Initial Application

Line No.	Particulars	Capitalization Ratio (%)	Capitalization Ratio ($)	Cost Rate (%)	Return ($)
	Debt				
1	Long-term Debt	56.00%	$1,313,941,324	5.37%	$70,558,649
2	Short-term Debt	4.00%	$93,852,952	2.07%	$1,942,756
3	**Total Debt**	60.00%	$1,407,794,276	5.15%	$72,501,405
	Equity				
4	Common Equity	40.00%	$938,529,517	9.85%	$92,445,157
5	Preferred Shares	0.00%	$ -	0.00%	$ -
6	**Total Equity**	40.00%	$938,529,517	9.85%	$92,445,157
7	**Total**	100.00%	$2,346,323,793	7.03%	$164,946,563

Settlement Agreement

Line No.	Particulars	Capitalization Ratio (%)	Capitalization Ratio ($)	Cost Rate (%)	Return ($)
	Debt				
1	Long-term Debt	56.00%	$1,286,989,547	5.37%	$69,111,339
2	Short-term Debt	4.00%	$91,927,825	2.46%	$2,261,424
3	**Total Debt**	60.00%	$1,378,917,371	5.18%	$71,372,763
	Equity				
4	Common Equity	40.00%	$919,278,248	9.58%	$88,066,856
5	Preferred Shares	0.00%	$ -	0.00%	$ -
6	**Total Equity**	40.00%	$919,278,248	9.58%	$88,066,856
7	**Total**	100.00%	$2,298,195,619	6.94%	$159,439,619

Per Board Decision

Line No.	Particulars	Capitalization Ratio (%)	Capitalization Ratio ($)	Cost Rate (%)	Return ($)
	Debt				
8	Long-term Debt	56.00%	$1,287,007,277	5.37%	$69,112,291
9	Short-term Debt	4.00%	$91,929,091	2.46%	$2,261,456
10	**Total Debt**	60.00%	$1,378,936,369	5.18%	$71,373,746
	Equity				
11	Common Equity	40.00%	$919,290,912	9.58%	$88,068,069
12	Preferred Shares	0.00%	$ -	0.00%	$ -
13	**Total Equity**	40.00%	$919,290,912	9.58%	$88,068,069
14	**Total**	100.00%	$2,298,227,281	6.94%	$159,441,816

Notes

(1) 4.0% unless an Applicant has proposed or been approved for another amount.

REVENUE REQUIREMENT WORK FORM

Version: 2.11

Ontario

Name of LDC: Toronto Hydro-Electric System Limited
File Number: EB-2010-0142
Rate Year: 2011

Revenue Sufficiency/Deficiency

Line No.	Particulars	Initial Application: At Current Approved Rates	Initial Application: At Proposed Rates	Settlement Agreement: At Current Approved Rates	Settlement Agreement: At Proposed Rates	Per Board Decision: At Current Approved Rates	Per Board Decision: At Proposed Rates
1	Revenue Deficiency from Below		$60,292,963		$3,705,382		$3,908,442
2	Distribution Revenue	$518,135,903	$518,135,899	$518,135,903	$518,135,903	$518,135,903	$518,135,902
3	Other Operating Revenue Offsets - net	$19,737,464	$19,737,464	$26,021,082	$26,021,082	$26,021,082	$26,021,082
4	**Total Revenue**	$537,873,367	$598,166,326	$544,156,985	$547,862,367	$544,156,985	$548,065,426
5	Operating Expenses	$405,080,571	$405,080,571	$376,632,387	$376,632,387	$376,832,387	$376,832,387
6	Deemed Interest Expense	$72,501,405	$72,501,405	$71,372,763	$71,372,763	$71,373,746	$71,373,746
	Total Cost and Expenses	$477,581,977	$477,581,977	$448,005,150	$448,005,150	$448,206,133	$448,206,133
7	**Utility Income Before Income Taxes**	$60,291,390	$120,584,349	$96,151,835	$99,857,217	$95,950,852	$99,859,293
8	Tax Adjustments to Accounting Income per 2009 PILs	($17,273,077)	($17,273,077)	($54,417,922)	($54,417,922)	($54,416,942)	($54,416,942)
9	**Taxable Income**	$43,018,313	$103,311,272	$41,733,913	$45,439,295	$41,533,910	$45,442,351
10	Income Tax Rate	28.25%	28.25%	28.25%	28.25%	28.25%	28.25%
11	**Income Tax on Taxable Income**	$12,152,674	$29,185,434	$11,789,830	$12,836,601	$11,733,329	$12,837,464
12	**Income Tax Credits**	($1,046,240)	($1,046,240)	($1,046,240)	($1,046,240)	($1,046,240)	($1,046,240)
13	**Utility Net Income**	$49,184,957	$92,445,157	$85,408,244	$88,066,856	$85,263,762	$88,068,069
14	**Utility Rate Base**	$2,346,323,793	$2,346,323,793	$2,298,195,619	$2,298,195,619	$2,298,227,281	$2,298,227,281
	Deemed Equity Portion of Rate Base	$938,529,517	$938,529,517	$919,278,248	$919,278,248	$919,290,912	$919,290,912
15	Income/Equity Rate Base (%)	5.24%	9.85%	9.29%	9.58%	9.27%	9.58%
16	Target Return - Equity on Rate Base	9.85%	9.85%	9.58%	9.58%	9.58%	9.58%
17	Sufficiency/Deficiency in Return on Equity	-4.61%	0.00%	-0.29%	0.00%	-0.31%	0.00%
18	Indicated Rate of Return	5.19%	7.03%	6.82%	6.94%	6.82%	6.94%
19	Requested Rate of Return on Rate Base	7.03%	7.03%	6.94%	6.94%	6.94%	6.94%
20	Sufficiency/Deficiency in Rate of Return	-1.84%	0.00%	-0.12%	0.00%	-0.12%	0.00%
21	Target Return on Equity	$92,445,157	$92,445,157	$88,066,856	$88,066,856	$88,068,069	$88,068,069
22	Revenue Deficiency/(Sufficiency)	$43,260,201	($0)	$2,658,612	$0	$2,804,307	$0
23	**Gross Revenue Deficiency/(Sufficiency)**	$60,292,963 **(1)**		$3,705,382 **(1)**		$3,908,442 **(1)**	

Notes:

(1) Revenue Sufficiency/Deficiency divided by (1 - Tax Rate)

REVENUE REQUIREMENT WORK FORM

Version: 2.11

Name of LDC: Toronto Hydro-Electric System Limited
File Number: EB-2010-0142
Rate Year: 2011

Revenue Requirement

Line No.	Particulars	Application		Settlement Agreement		Per Board Decision	
1	OM&A Expenses	$220,014,886		$231,014,224		$231,214,224	
2	Amortization/Depreciation	$178,263,303		$138,815,781		$138,815,781	
3	Property Taxes	$6,802,382		$6,802,382		$6,802,382	
4	Capital Taxes	$ -		$ -		$ -	
5	Income Taxes (Grossed up)	$28,139,192		$11,790,361		$11,791,223	
6	Other Expenses	$ -					
7	Return						
	Deemed Interest Expense	$72,501,405		$71,372,763		$71,373,746	
	Return on Deemed Equity	$92,445,157		$88,066,856		$88,068,069	
8	Distribution Revenue Requirement before Revenues	$598,166,326		$547,862,367		$548,065,426	
9	Distribution revenue	$578,428,862		$521,841,285		$522,044,344	
10	Other revenue	$19,737,464		$26,021,082		$26,021,082	
11	**Total revenue**	$598,166,326		$547,862,367		$548,065,426	
12	**Difference (Total Revenue Less Distribution Revenue Requirement before Revenues)**	($0)	(1)	$0	(1)	$0	(1)

Notes

(1) Line 11 - Line 8

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES ON ISSUE 1.1

INTERROGATORY 9:

Reference(s): **T4/S E1.1/p. 7 Incremental Capital Workform**

A section of the above reference is reproduced below.

Rate Class	Fixed Metric	Vol Metric	Billed Customers or Connections A	Billed kWh B	Billed kW C
Residential	Customer	kWh	591,496	5,105,974,275	0
Residential Urban	Customer	kWh	24,898	99,791,184	0
General Service Less Than 50 kW	Customer	kWh	65,799	2,095,343,918	0
General Service 50 to 999 kW	Customer	kW	12,873	10,189,051,346	26,712,248
General Service 1,000 to 4,999 kW	Customer	kW	509	4,828,382,733	10,972,419
Large Use	Customer	kW	47	2,263,227,585	5,267,224
Street Lighting	Connection	kW	162,964	112,727,603	321,995
Unmetered Scattered Load	Connection	kWh	1,107	52,097,299	0
Unmetered Scattered Load	Connection	kWh	12,159	0	0

Please confirm that these entries are in conformity with the values provided in THESL's December 31, 2010 RRR 2.1.5 filing. If any are not, please state what they are and provide an explanation.

RESPONSE:

The values for customers and loads shown on page 7 of the Incremental Capital Workform are THESL's most up-to-date estimates for 2010. These differ from the RRR 2.1.5 filing in the following ways:

1) The customer and connection values in the Workform reflect a mid-year count, whereas those in the RRR filing are year-end values.
2) The customer numbers and loads for the Competitive Sector Multi-Unit Residential class (shown as Residential Urban in the Workform and other ICM models) are estimated based on the evidence provided in EB-2010-0142, and the Residential customers and loads are adjusted to reflect the separation of the new

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES ON ISSUE 1.1

rate class as ordered by the OEB. There has been no RRR filing for the new rate class.

3) Class loads in the Workform reflect information that is updated regularly based on additional information available from the billing system (such as billing corrections which can be made after actual billing). The information in the RRR filings reflects the most recent information at the reporting cut-off date. Differences between updated estimates and the RRR filings are generally minimal.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES ON ISSUE 1.1

INTERROGATORY 10:

Reference(s): **T2/p. 14 and *Chapter 3 of the Filing Requirements For Electricity Transmission and Distribution Applications*, p 10**

In the first reference, THESL begins its discussion as to how its application meets the criteria established by the Board in the Filing Requirements.

One of the requirements outlined in the second reference is "A description of the actions the distributor will take in the event the Board does not approve the application." in reference to ICM requests.

Please provide this information.

RESPONSE:

Should the Board reject this application, THESL would likely be required to channel all its available resources to address defective equipment on a strictly emergency reactive basis. Of course, THESL will always do its best to ensure that its customers, from residential customers to the largest commercial and manufacturing entities depending on our system, will receive electricity according to their reasonable expectations. However it is the considered view of THESL Asset Management and Operations Staff respectively that where THESL is unable to replace end-of-life (or past end-of-life) or defective equipment as a result of the absence of funding service disruptions will likely increase (both in frequency and duration), as will the likely costs of emergency repairs to failing equipment, and necessary projects would be delayed. Further, THESL is concerned that while the service levels to customers will likely be lower overall in this circumstance, the costs to ratepayers would likely be higher overall. This is so because responding to

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES ON ISSUE 1.1

defective and obsolete equipment on an emergency, reactive basis is generally more expensive than the orderly replacement contemplated in this application. The particular consequences of inaction as they relate to each specific project, as well as the sub-optimal approach of addressing these problems strictly on a reactive basis, are outlined in the non-discretionary justification within each subsection in Tab 4.

RESPONSES TO CONSUMERS COUNCIL OF CANADA INTERROGATORIES ON ISSUE 1.1

INTERROGATORY 1:

Reference(s): **Tab 2/p. 3**

The evidence states, "To the greatest extent possible THESL has prepared this application in accordance with Chapter 3 of the Board's Filing Requirements for Transmission and Distribution Applications dated June 22, 2011, as well as other guidelines and directions from the Board, including the Board's January 5, 2012 Decision with Reasons on the Preliminary Issue in EB-2011-0144 together with Board Decisions on other ICM applications." Please indicate where THESL has deviated from the Filing Requirements. Where THESL has deviated from the Filing Requirements please set out the reasons why it has done so.

RESPONSE:

THESL believes that it has met the OEB's explicit filing requirements. Where THESL has made proposals on issues for which the filing guidelines are silent (i.e., the multi-year proposal and certain applications of the ICM eligibility factors), or suggested an alternative regulatory approach (i.e., the alternate ICM revenue requirement methodology), THESL has explained its reasons for doing so in its pre-filed evidence and further through its responses to interrogatories.

RESPONSES TO ENERGY PROBE RESEARCH FOUNDATION INTERROGATORIES ON ISSUE 1.1

INTERROGATORY 1:

Reference(s): Application – Disclaimer

a) Is the Disclaimer authorized by Mr. J.S. Coulliard and THESL Counsel?

RESPONSE:

a) This disclaimer is a general corporate document and is not, nor is it required to be, authorized by any particular individual.

b) If so, why is it not signed by those parties?

RESPONSE:

b) See response to a) above.

c) Please provide a copy of the similar Disclaimer from the previous Rates Case before the Board (EB-2010-0142).

RESPONSE:

c) No such document exists.

RESPONSES TO ENERGY PROBE RESEARCH FOUNDATION INTERROGATORIES ON ISSUE 1.1

INTERROGATORY 2:

Reference(s): EB-2010-0142 Settlement Agreement

a) What was the Framework for the 2011 Settlement Agreement?

- **That 2011 was a "normal" Cost of service Year, or**
- **That 2011 was a rebasing year?**

RESPONSE:

a) THESL filed its application for 2011 rates (EB-2010-0142) on a Cost of Service basis and participated in the Settlement process on that understanding.

b) Please discuss the implications of your answers for this application.

RESPONSE:

b) THESL does not perceive any specific implications of the framework for the 2011 Settlement Agreement for this application, except with regard to the 2011 Half Year Rule issue. With respect to the 2011 Half Year Rule portion of the application, see THESL response to OEB Staff Interrogatory 13 (Tab 6C, Schedule 1-13).

RESPONSES TO ENERGY PROBE RESEARCH FOUNDATION INTERROGATORIES ON ISSUE 1.1

INTERROGATORY 3:

Reference(s): **EB-2010-0142 Exhibit B1, Tab 14, Schedule 1**

a) Please provide the last 5 years (2007-2011) Service Quality Indicators and also please add 2012 YTD and 2012E values.

RESPONSE:

a)

Indicator	2007	2008	2009	2010	2011	2012 (YTD)[1]	2012 (E)
SAIFI	2.01	1.76	1.64	1.77	1.62	0.98	1.44
SAIDI	1.35	1.24	1.38	1.29	1.43	0.79	1.09
CAIDI	0.67	0.70	0.84	0.73	0.88	0.80	0.76

(MEDs [2] not included)

b) Please provide the Incidence/frequency of Momentary Interruptions 2007-2011 and add 2012 YTD and 2012E values.

[1] January through August.
[2] "Major Event Days" as defined by the IEEE 1366.

RESPONSES TO ENERGY PROBE RESEARCH FOUNDATION INTERROGATORIES ON ISSUE 1.1

RESPONSE:

b)

Year	Momentary interruptions
2007	1,128
2008	1,246
2009	1,176
2010	1,004
2011	1,165
2012 (YTD)[3]	813
2012 E	1,157

c) Please discuss changes/trends in SQIs going forward into the IRM period.

RESPONSE:

c) Without the capital expenditures identified in this application, THESL expects the system reliability (both SAIFI and SAIDI) will likely deteriorate from 2012 onwards as more assets reach end of life that are not proactively replaced.

d) Will the ICM/CAPEX program have a positive impact on SQIs? Please discuss.

RESPONSE:

d) Several of the ICM projects will likely have a positive impact on SQIs. For example, the replacement of failing assets such as direct buried cables will likely have a positive effect on THESL’s SQIs. In addition, some of the ICM projects that are primarily directed at maintaining system safety will also likely have a positive effect on THESL’s SQIs.

RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORIES ON ISSUE 1.1

INTERROGATORY 1:

Reference(s): **Tab 2. page 3, lines 12-14**

a) Please specifically identify those “new approaches” proposed by THESL that deal with particular issues the Board has not “expressly pronounced on”.

RESPONSE:

a) THESL regards the areas in which it has offered new approaches as being:

i. Multi-year ICM
ii. Alternate revenue requirement methodology
iii. Recognition of 2011 year-end ratebase

RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORIES ON ISSUE 1.1

INTERROGATORY 2:

Reference(s): **Tab 3, Schedule E1, page 4**
Tab 2, Appendix 1, page 2

a) Please reconcile the “% of Revenue” values shown columns K to N of the first reference with those shown in columns A to C of the second reference. (Note: The values in columns K-M of the first reference must be multiplied by the value in column N to get the comparable values in the second reference)

RESPONSE:

a) The values for “% of Revenue” in Tab 2, Appendix 1 are incorrect. THESL is providing a corrected version of the referenced document. See also EP interrogatory 7a (Tab 6C, Schedule 7-7, part a).

RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORIES ON ISSUE 1.1

INTERROGATORY 3:

Reference(s): Tab 4. Schedule E1.1, pages 5 and 7-9

a) Please explain the basis for the loads/customer count and rates used on each of the following three pages: 5, 7 and 8.

RESPONSE:

a) The loads and customer counts on Pages 5 and 8 ("Re-based billed customer, connections, kWh and kW") are based on 2011 OEB-approved Load and Customer forecast. The load and customer count on Page 7 represents 2010 actual billing units. The rates on all pages are the current 2011 Board-approved rates. Note that the customer/connection rates shown on page 8 for Residential Urban and Unmetered Scattered load are incorrect. THESL has advised the OEB and intervenors that it will be filing an update to its pre-filed evidence. THESL believes that its pending update will fundamentally affect THESL's response to this interrogatory, such that providing a response now would not materially assist the OEB or intervenors. THESL accordingly defers its response to this part of the interrogatory until after its forthcoming evidentiary update.

b) Please review the rates and loads associated with each class on pages 5 and 8 and reconcile any differences. For example, on page 5 the second USL class associates the $0.49 service charge with 21.729 connections and no volumes or volumetric charges. However, on page 8, the first USL class associates the $0.49 service charge with 1,130 connections as well as volumetric use and volumetric charges.

RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORIES ON ISSUE 1.1

RESPONSE:

b) Please see the response in part (a). THESL has a three-part rate for USL customers. In order for these rates to be accommodated in the OEB's models, the class is shown twice – once with the monthly service charge per customer and the volumetric charge, and the second time with the connection charge.

c) Please provide weather normalized usage values for 2010.

RESPONSE:

c) The table below presents the 2010 loads normalized to 2011 OEB-approved weather variables.

Customer Class	Weather-Normalized Billed kWh	Weather-Normalized Billed kVA
Residential	5,083,877,203	
Residentail Urban	99,359,319	
General Service less than than 50 kW	2,084,449,526	
General Service 50 to 999 kW	10,188,050,194	26,708,165
General Service 1,000 to 4,999 kW	4,830,124,728	10,974,154
Large Use	2,260,681,437	5,260,625
Street Lighting	112,727,603	321,995
USL	52,097,299	

d) Please re-do page 7 based on weather normalized loads.

RESPONSE:

d) Please see attached Appendix A, which uses the values from the above table.

Toronto Hydro-Electric System Limited
EB-2012-0064
Tab 6A
Schedule 11-3
Appendix A
Filed: 2012 Oct 5
(1 page)

Load Actual - Most Recent Year

Rate Class	Fixed Metric	Vol Metric	Billed Customers or Connections A	Billed kWh B	Billed kW C	Base Service Charge D	Base Distribution Volumetric Rate kWh E	Base Distribution Volumetric Rate kW F	Service Charge Revenue G = A * D * 12	Distribution Volumetric Rate Revenue kWh H = B * E	Distribution Volumetric Rate Revenue kW I = C * F	Total Revenue by Rate Class J = G + H + I
Residential	Customer	kWh	591,496	5,083,877,203	0	$18.25	$0.0151	$0.0000	$129,537,624	$76,614,029	$0	$206,151,653
Residential Urban	Customer	kWh	24,898	99,359,319	0	$17.00	$0.0257	$0.0000	$5,079,192	$2,548,567	$0	$7,627,759
General Service Less Than 50 kW	Customer	kWh	65,799	2,084,449,526	0	$24.30	$0.0225	$0.0000	$19,186,988	$46,837,581	$0	$66,024,569
General Service 50 to 999 kW	Customer	kW	12,873	10,188,050,194	26,708,165	$35.56	$0.0000	$5.5956	$5,493,167	$0	$149,448,208	$154,941,375
General Service 1,000 to 4,999 kW	Customer	kW	509	4,830,124,728	10,974,154	$686.46	$0.0000	$4.4497	$4,192,898	$0	$48,831,693	$53,024,591
Large Use	Customer	kW	47	2,260,681,437	5,260,625	$3,009.11	$0.0000	$4.7406	$1,697,138	$0	$24,938,519	$26,635,657
Street Lighting	Connection	kW	162,964	112,727,603	321,995	$1.30	$0.0000	$28.7248	$2,542,238	$0	$9,249,232	$11,791,471
Unmetered Scattered Load	Connection	kWh	1,107	52,097,299	0	$4.84	$0.0607	$0.0000	$64,295	$3,162,306	$0	$3,226,601
Unmetered Scattered Load	Connection	kWh	12,159	0	0	$0.49	$0.0000	$0.0000	$71,495	$0	$0	$71,495
									$167,865,035	**$129,162,483**	**$232,467,652**	**$529,495,170**

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES ON ISSUE 1.2

INTERROGATORY 11:

Reference(s): T1/p.5 and T2/p. 4

In the first reference, it is stated that THESL is proposing that:

> "the OEB approve forgone revenue rate riders as its [sic] did in THESL's 2011 rates case (EB-2011-0144), to allow THESL an opportunity to recover the incremental revenue approved by the Board for the period between when rates became interim (June 1, 2012 on THESL's proposal) and when new rates are implemented (at the conclusion of this proceeding)"

In the second reference, THESL makes the following statement:

> "THESL proposes specifically that any revenue deficit arising from an effective date for 2012 rates after May 1, 2012 be included in the reconciliation upon rebasing."

Please reconcile these two statements and include further clarification of the second statement.

RESPONSE:

In previous circumstances, the OEB has determined an annual revenue requirement that was to be recovered over a period shorter than 12 months. In those circumstances, THESL has proposed, and the OEB has accepted, that basic rates (which would have been applicable for 12 months) be struck and be augmented with 'foregone revenue' rate riders with a fixed expiry date. On that basis, the basic rates are those that are appropriate for continuation and subsequent adjustment, and the rate riders expire when their purpose has been fulfilled.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES ON ISSUE 1.2

In present circumstances, the total rate change requested by THESL in this application can be considered in two parts. First, with respect to the PCI adjustment to existing rates, THESL anticipates and requests that the OEB follow past practice by adjusting existing base rates by the PCI factor effective as of a date to be determined late in 2012 or early in 2013. Those new basic rates would be prospective only in application. Then, in order to reflect the fact that existing rates became interim June 1, 2012, the OEB could approve 'foregone revenue' rate riders with a definite expiry date to permit THESL to recover, prospectively, the foregone revenue that would have been generated through the PCI adjustment, for the period from June 1, 2012 to the date of new rate implementation.

Second, with respect to the ICM rate adders, THESL believes that since those are rate adders subject to deferral treatment (i.e., later true up and reconciliation), the OEB can determine amounts allowable for 2012 ICM expenditures and the corresponding rate adders for prospective implementation at any time without reference to when existing base rates became interim. Because the 2012 approved ICM expenditures would be in the nature of ratebase additions, the revenue requirement attracted by them would persist through 2013 and 2014 until rebasing. Again, the ICM rate adders for any amounts the OEB may approve will very likely not be determined until late 2012 or 2013. At that point, because the majority of the 2012 rate year would already have passed, the OEB may wish to consider the introduction of 2012 ICM rate adders that would recover 36 months of cost related to the 2012 ICM expenditure over a shorter period (perhaps 27 months) ending April 30, 2014.

While the concept of a 'foregone ICM rate adder' exists and might be appropriate in other circumstances, THESL believes that effectively compressing recovery of the

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES ON ISSUE 1.2

approved 2012 ICM-related revenue requirement into a period of just a few months would present an abrupt, transient rate change that would be unnecessarily difficult for customers.

Alternatively (and with respect to the second statement) the OEB could determine that the 'basic' rate adders corresponding to any approved 2012 ICM amounts be implemented at levels as though 36 months were available to recover the corresponding costs and direct that the revenue shortfall created by delayed implementation of those 2012 ICM adders be trued up at the conclusion of the ICM period.

For purposes of avoiding large rate changes and systematic, significant variances subject to true up, THESL prefers an approach under which 2012 ICM rate adders are implemented for a fixed period commencing pursuant to the OEB's decision in this proceeding and ending April 30, 2014. Any variance between the allowed ICM rate adder revenue and that actually collected through rates would continue to be subject to true up.

RESPONSES TO ASSOCIATION OF MAJOR POWER CONSUMERS IN ONTARIO INTERROGATORIES ON ISSUE 1.2

INTERROGATORY 1:

Reference(s): Tab 2

a) Please summarize the opportunities for efficiencies and any potential cost savings resulting from THESL's proposed 3 year IRM/ICM approach.

RESPONSE:

a) Please see THESL's response to OEB Staff interrogatory 75(a) (Tab 6G, Schedule 1-75).

b) Please summarize the value/benefit to the customer from THESL's proposed 3 year IRM/ICM approach.

RESPONSE:

b) In addition to the benefits listed in the interrogatory responses cited in part (a) above, THESL believes that a multi-year IRM/ICM application promotes regulatory efficiency by reducing the costs of preparing, reviewing, and deciding multiple applications.

c) Please discuss the how the Board's latest announcement (September 14, 2012 OEA Speaker Series) on the Renewed Regulatory Framework for Electricity impacts THESL's proposed approach.

RESPONSES TO ASSOCIATION OF MAJOR POWER CONSUMERS IN ONTARIO INTERROGATORIES ON ISSUE 1.2

RESPONSE:

c) Please see THESL's response to SEC interrogatory 4 (Tab 6D, Schedule 10-4).

RESPONSES TO CANADIAN UNION OF PUBLIC EMPLOYEES, LOCAL ONE INTERROGATORIES ON ISSUE 1.2

INTERROGATORY 1:

Reference(s): **TAB 2 - Managers Summary, Page 9, Line 22 – Page 10, Line 13**

Please explain in detail the paragraphs in THESL's application noted above (and included below for your convenience).

Please provide the following details:

a) What percentage of THESL's annual capital work program has, or will be completed by an eternal contractor/vendor for the years 2011, 2012, 2013 and 2014.

RESPONSE:

a) For 2011, the percentage of THESL's annual capital work program completed by external contractors/vendors was approximately 44%. For 2012 August year-to-date, the percentage was approximately 36%. When considering the percentage of the capital work program completed by external contractors/vendors, it is also important to note that, in absolute terms, THESL's spending on external contractors performing capital work has decreased significantly in 2012. THESL's absolute spending on the annual capital work program is discussed in the response to (b), below.

THESL has advised the OEB and intervenors that it will be filing an update to its pre-filed evidence. THESL believes that its pending update will fundamentally affect THESL's response to this interrogatory, such that providing a response now would

RESPONSES TO CANADIAN UNION OF PUBLIC EMPLOYEES, LOCAL ONE INTERROGATORIES ON ISSUE 1.2

not materially assist the OEB or intervenors. THESL accordingly defers its response in respect of the forecasted years until after its forthcoming evidentiary update.

b) What are the dollar values of THESL's annual capital work program that have, or will be been completed by external contractors/vendors for the years 2011, 2012, 2013 and 2014.

RESPONSE:

b) For 2011, the dollar value of THESL's annual capital work program completed by external contractors/vendors was approximately $141.4 million. For 2012 August year-to-date, the dollar value was approximately $38.7 million.

For the reasons described in part (a) above, THESL defers its response in respect of the forecasted years until after its forthcoming evidentiary update.

c) Please indicate how many external contracts/vendors THESL currently uses for the capital work program, and how many are planned for the years 2013, and 2014.

RESPONSE:

c) THESL currently has contracted with six external contractor firms. This number is not expected to change during the period 2012-2014.

RESPONSES TO CANADIAN UNION OF PUBLIC EMPLOYEES, LOCAL ONE INTERROGATORIES ON ISSUE 1.2

INTERROGATORY 5:

Reference(s): **Section C / Schedule C2 – 2011 Carryover Projects, Pages 4 and 5**

a) Please provide the detail for how much of the 2011 Carryover projects value for 2012 is associated with Customer Care and Service Area Enhancements.

RESPONSE:

a) Of the 2011 carryover amount $4,900,000 is associated with Customer Care and Service Area Enhancements. Please see the table below.

Project	2011 Carryover Amount ($M)	Description
CUSTOMER SELF SERVICE	$2.4	Projects to meet the growing needs and expectations of tech savvy customers and improve online presence. THESL is enhancing customer experience via online self serve features (such as customer profile creation/ change/deletion and access to time of use rate information).
REGULATORY REQUIREMENTS	$2.5	The project also implements solutions to address changing regulatory requirements mainly the use of 'register' data instead of 'interval' data for time-of-use billing and suite meter automated reading.
TOTAL	$4.9	

b) Please provide specific details of the costs within that above-referenced total. Please identify if any of those projects include self-service enhancements to the call centre telephone system.

RESPONSES TO CANADIAN UNION OF PUBLIC EMPLOYEES, LOCAL ONE INTERROGATORIES ON ISSUE 1.2

RESPONSE:

b) None of the 2011 carryover projects include self-service enhancements to the call centre telephone system.

RESPONSES TO CONSUMERS COUNCIL OF CANADA INTERROGATORIES ON ISSUE 1.2

INTERROGATORY 2:

Reference(s): **Tab 2**

Please provide all materials provided to THESL's Board of Directors and Senior Management when seeking approval of the 2012-2014 application.

RESPONSE:

The following document was provided to THESL's Board of Directors concerning the 2012-2014 application.

1. *Memorandum from Borden Ladner Gervais LLP regarding IRM/ICM process, dated January 27, 2012.*

   THESL declines to produce this document on the basis that the materials and information sought are privileged as communications between solicitor and client and/or materials produced in contemplation of litigation.

The following documents were provided to THESL's Senior Management:

2. *Memorandum from Amanda Klein (THESL in-house counsel) regarding the ICM eligibility criteria dated February 11, 2012*; and
3. *Power Point Presentation from Amanda Klein (THESL in-house counsel) and Borden Ladner Gervais LLP to THESL Executive regarding 2012-2014 IRM/ICM application dated April 11, 2012.*

   THESL declines to produce these documents on the basis that the materials and information sought are privileged as communications between solicitor and client and/or materials produced in contemplation of litigation.

RESPONSES TO CONSUMERS COUNCIL OF CANADA INTERROGATORIES ON ISSUE 1.2

INTERROGATORY 3:

Reference(s): Tab 2

Please provide a description of all of the alternatives THESL considered for 2012-2014 rates and indicate why those alternatives were rejected.

RESPONSE:

Initially THESL sought to establish 2012-2014 rates by way of the EB-2011-0144 COS application. That application was dismissed by the OEB, for reasons identified in its Decision of January 5, 2012. Following this dismissal, THESL currently has no other funding options but by way of the IRM/ICM mechanism. It is THESL's view that substantial investment in its distribution system is essential and that this investment cannot be funded through the simple IRM framework (i.e., without the ICM). Consequently, THESL's only option was to prepare an ICM application.

RESPONSES TO CONSUMERS COUNCIL OF CANADA INTERROGATORIES ON ISSUE 1.2

INTERROGATORY 4:

Reference(s): **Tab 2/ p. 7**

Please explain what is meant by the following comment, "THESL understands that delays and advancements in job timing would be assessed as to their impacts on the final approved revenue requirements stemming from the ICM projects upon true-up at the time of rebasing." What, specifically, is THESL proposing regarding how its rates would be rebased?

RESPONSE:

The quoted comment refers to THESL's expectation that the OEB will examine THESL's actual spending on ICM projects at the time of rebasing and "true up" against the forecasts contained in this application. The application does not contain any proposal for rebasing.

RESPONSES TO CONSUMERS COUNCIL OF CANADA INTERROGATORIES ON ISSUE 1.2

INTERROGATORY 5:

Reference(s): Tab 2/ p. 7

Please explain specifically what type of reporting THESL is proposing with respect to "the status and progress for each project." Please provide any templates that have been prepared.

RESPONSE:

THESL will be guided in this regard by any direction provided by the OEB. At the present time, THESL envisions reporting to the OEB annually in 2013, 2014, and 2015, as required by the Filing Requirements. For each project segment, these annual reports would provide information on expenditures for the prior ICM year, the completion status of the project segment, and analysis of variance between forecast and actual expenditures. THESL has not yet developed reporting templates, but once again, will be guided by any direction from the OEB in this regard. Should the OEB consider it advisable, THESL will work with Intervenors and OEB Staff to develop an appropriate true-up methodology. In addition, THESL of course intends to maintain its reporting under the RRR requirements, which provides the OEB and other parties transparency with respect to THESL's overall financial condition and earnings.

RESPONSES TO CONSUMERS COUNCIL OF CANADA INTERROGATORIES ON ISSUE 1.2

INTERROGATORY 6:

Reference(s): **Tab 2/ p. 8**

Does THESL plan to update its application and proposed capital budgets for the three-year period based on 2012 actual expenditures to date? If not, why not?

RESPONSE:

Yes. Please see THESL's correspondence to the OEB and parties on this topic dated September 13, 2012 and served and filed in this proceeding.

RESPONSES TO CONSUMERS COUNCIL OF CANADA INTERROGATORIES ON ISSUE 1.2

INTERROGATORY 7:

Reference(s): Tab 2/ p. 9

The evidence states that, "It is also essential for the purpose of obtaining the most favourable terms from external contractors that THESL be able to offer those contractors the prospect of a predictable and preferably steady volume of work."

Has THESL already entered into arrangements with contractors to undertake the entire proposed 3-year capital spending program?

Please explain the comments, "The costs of the ICM projects proposed in this Application are estimated based on the existing contracts between THESL and its contractors. However, the availability of this pricing may be contingent on both the level and predictability of the work that THESL can offer those contractors."

Please elaborate on how the costs of those projects might change depending upon contractor pricing?

RESPONSE:

THESL's contracts are not based on the entire spending program, but rather are structured as competitively bid unit prices for all types of work activities the contractor can undertake within the three-year term. The contracts do not provide for a guaranteed minimum or maximum amount of work. However, the contractors will likely have difficulty undertaking work if they lack available labour resources or specific required skill-sets. For example, labour resources with skills in PILC cable installation and jointing or in working on overhead box construction are typically difficult to obtain.

RESPONSES TO CONSUMERS COUNCIL OF CANADA INTERROGATORIES ON ISSUE 1.2

THESL will necessarily have greater difficulty entering into contracts and face higher costs for contracts that it enters into should the level of the work be limited and if the predictability of the work is uncertain.

Since pricing is fixed by each contractor's unit price bids, a reduction in the expected level of work could result in the inability of a contractor to attract resources to undertake the (reduced) level of work. In that situation, THESL would likely have to tender specific jobs, which would be bid on individually by the contractor firms and would likely include cost premiums to attract resources.

RESPONSES TO CONSUMERS COUNCIL OF CANADA INTERROGATORIES ON ISSUE 1.2

INTERROGATORY 8:

Reference(s): Tab 2/ p. 2

The evidence states that, "The specific projects THESL includes within the ICM reflect the minimum amount of infrastructure renewal THESL must undertake over the next three years to maintain current overall levels of safety and reliability". Please explain, specifically, how THESL determined that this level of spending represented the "minimum" level of for the next three years?

RESPONSE:

Please refer to THESL's response to SEC interrogatory 6 and OEB Staff interrogatory 15 (Tab 6E, Schedule 10-6 and Tab 6E, Schedule 1-15).

RESPONSES TO CONSUMERS COUNCIL OF CANADA INTERROGATORIES ON ISSUE 1.2

INTERROGATORY 9:

Reference(s): **Tab 2**

Please provide, for the period 2006-2012 THESL's as filed forecast, Board approved and actual capital expenditures in the same format as Exhibit D1/T7/S1/p. 16 (EB-2010-0142).

RESPONSE:

THESL is not able to present the capital expenditures for 2006 and 2007 in the requested format because it did not track capital costs in the same manner as that presented in Exhibit D1, Tab 7, Schedule 1 of EB-2010-0142. The table below presents the actual capital expenditures from 2008 to 2011 in the format requested. With respect to 2012 information, THESL has advised the OEB and intervenors that it will be filing an update to its pre-filed evidence. THESL believes that its pending update will fundamentally affect THESL's response, such that providing a response now would not materially assist the OEB or intervenors. THESL accordingly defers its response in respect of the 2012 information until after its forthcoming evidentiary update.

RESPONSES TO CONSUMERS COUNCIL OF CANADA INTERROGATORIES ON ISSUE 1.2

	2008 Actual	2009 Actual	2010 Actual	2011 Actual
OPERATIONAL INVESTMENTS				
Grid System Investments				
Underground System	62.0	68.5	111.6	99.0
Overhead System	19.3	20.5	31.7	39.3
Network System	4.7	5.0	7.4	4.8
Stations	16.8	14.1	17.0	18.2
Total Grid System Investments	**102.9**	**108.2**	**167.7**	**161.4**
Reactive Work	19.3	20.7	25.1	28.6
Customer Connections	42.8	37.6	42.6	58.2
Customer Capital Contribution	(32.7)	(23.4)	(26.6)	(29.8)
Externally Initiated Plant Relocations	-	-	-	7.8
Capital Contributions to HONI	0.4	0.3	1.1	27.8
Engineering Capital	26.4	25.8	34.5	23.6
AFUDC	2.0	2.8	3.5	5.2
Other	(4.3)	3.1	12.3	(4.2)
Total Distribution Plant Capital	**156.8**	**175.1**	**260.3**	**278.6**
CORPORATE OPERATIONAL INVESTMENTS				
Fleet &Equipment Services	7.9	9.9	10.6	11.8
Facilities	3.4	7.6	12.1	25.3
Other	0.3	3.2	-	-
Total Corporate Operational Investments	**11.6**	**20.7**	**22.7**	**37.1**
CUSTOMER SERVICES				
Wholesale Metering	4.4	(0.5)	1.8	-
Smart Metering	5.6	2.6	0.4	10.1
Suite Metering	2.7	3.3	6.4	10.2
Other	0.5	0.3	0.2	0.0
Total CUSTOMER SERVICES	**13.2**	**5.6**	**8.8**	**20.3**
Total INFORMATION TECHNOLOGY	**24.1**	**35.7**	**33.0**	**32.4**
Total OPERATIONAL INVESTMENTS	**205.7**	**237.1**	**324.7**	**368.4**
CRITICAL ISSUES				
Standardization	-	5.7	30.2	44.6
Downtown Contingency	-	-	1.1	4.7
FESI / WPF	-	-	16.7	19.3
Stations System Enhancements	-	(1.0)	5.8	4.7
Secondary Upgrade	-	-	2.6	3.9
Total CRITICAL ISSUES		**4.7**	**56.4**	**77.1**
TOTAL CAPITAL	**205.7**	**241.7**	**381.1**	**445.5**

RESPONSES TO CONSUMERS COUNCIL OF CANADA INTERROGATORIES ON ISSUE 1.2

INTERROGATORY 10:

Reference(s): **Tab 2**

Please provide the level of capital expenditures that THESL agreed to in the 2010 and 2011 Settlement Agreements.

RESPONSE:

The settlement proposal approved by the Board for 2010 includes capital expenditures of $350M plus a deferral account for an additional $27.8M in capital spending for Transit City. THESL's 2011 Settlement Agreement capital expenditures was $378.8M.

RESPONSES TO CONSUMERS COUNCIL OF CANADA INTERROGATORIES ON ISSUE 1.2

INTERROGATORY 11:

Reference(s): **Tab 2**

If the Board rejects THESL's proposal for a rate adjustment for 2012, how would this impact THESL's capital expenditure budgets for 2013 and 2014?

RESPONSE:

THESL cannot answer in the abstract without knowing the reason(s) given by the OEB for any hypothetical rejection of THESL's application. It would be necessary for THESL to thoroughly assess the decision and analyze the reasons given, and to the extent necessary, reshape its work program to address the concerns stated in the decision. Please also see THESL's response to OEB Staff interrogatory 10 (Tab 6A, Schedule 1-10) and 12 (Tab 6D, Schedule 1-12).

Nevertheless, THESL expects that the need for the work proposed in this application will remain and will intensify until THESL is able to complete it. Therefore, after fully reviewing and considering the content of the decision emerging from this proceeding, THESL would expect to take its next opportunity to seek OEB approval of the work it considers to be essential.

RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORIES ON ISSUE 1.2

INTERROGATORY 4:

Reference(s): **Tab 2, page 6, lines 29-3**

a) Please explain more fully what THESL means by:
   - "each distinct year being severable", and
   - "each year having distinct distribution rates".

   Are these points (particularly the last one) meant to refer to the ICM rate riders or the overall distribution rates?

RESPONSE:

a) By 'severable', THESL means that each of 2012, 2013, and 2014 can be considered distinctly by the OEB in terms of ICM projects, ICM rate adders, and rates overall. THESL contrasts this approach to one in which the three-year period would be considered monolithically, with one set of projects covering the entire period, one set of adders, and one set of rates.

   The phrase "each year having distinct distribution rates" means that under this approach, each year would have a distinct set of ICM rate adders, with those for 2012 and 2013 effective for three and two years respectively, and each year would have distinct base rates escalated by the corresponding PCI factor in the applicable year. The phrase 'distribution rates' refers to ICM adders and base rates collectively.

RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORIES ON ISSUE 1.2

INTERROGATORY 5:

Reference(s): **Tab 2, page 8, lines 7-8**

a) Is THESL proposing to establish a variance account that will return to ratepayers any variance in the 2012-2014 revenue offsets from those included in the 2011 approved revenue requirement and rates?

RESPONSE:

a) No.

b) If not, please explain how for the years 2012-2014 the revenues THESL gains from other sources will be "returned" to ratepayers.

RESPONSE:

b) THESL understands that under IRM, the level of revenue offsets approved in the rebasing year is implicitly continued until reset at the next rebasing, regardless of whether those offsets are realized or not.

RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORIES ON ISSUE 1.2

INTERROGATORY 6:

Reference(s): **Tab 2, page 8**

a) Does THESL agree that one of the objectives of IRM is to provide electricity distributors with increased incentives to improve efficiency in the use of resources? If not, why not?

RESPONSE:

a) Yes.

b) THESL claims that there are no other resources that it can draw upon to fund the costs of investments it makes during the IRM period. Please confirm that any additional resources (e.g. funds) freed up through increased efficiencies (over and above those reflected in rates) would be available to help fund new investments. If not, why not?

RESPONSE:

b) To the extent that earnings increased due to any factor (including, for example, increased revenue due to increased throughput), all or a portion of those earnings could be made available to be re-invested in the distribution system. However, that extra amount of re-investment would need to attract the corresponding capital-related costs in revenue requirement.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES ON ISSUE 1.3

INTERROGATORY 13:

Reference(s): T2/p. 3

It is stated that:

> "THESL proposes that the Board recognize in 2012 distribution rates the Board-approved, actual year-end ratebase of 2011, which is materially larger than the average ratebase upon which 2011 rates were set."

Please state whether there are any circumstances specific to THESL that would justify a departure from the Board's established practices regarding the half-year rule.

RESPONSE:

The circumstances that are specific to THESL in this regard are that:

1. <u>Change in Manner of Regulation.</u> THESL prepared its 2011 rate application on a Cost of Service basis, in contemplation of being able to follow that year with a subsequent Cost of Service application. THESL's CAPEX proposals were made on that basis. THESL accepts that the OEB determined that it would treat the 2011 application as a rebasing application, but nevertheless the OEB approved in the EB-2010-0142 Decision 2011 capital expenditures of $378.8 million. As noted at Tab 2, pages 4 through 6, these approved capital expenditures exceeded depreciation by $240 million, and through the operation of the half year rule, $120 million of approved capital expenditures were excluded from ratebase for the purpose of determining 2011 rates.
2. <u>THESL was obliged to spend OEB-approved CAPEX.</u> Even apart from the pressing need for the capital expenditures proposed in the 2011 application, given the OEB's approval of those expenditures, it was not open to THESL to curtail its

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES ON ISSUE 1.3

actual CAPEX to the much lower levels that would have been consistent with maintaining the 2011 year end ratebase equal to the 2011 average ratebase upon which rates were predicated. In order to maintain a stable ratebase across 2011, and thus avoid the problem of unrecognized year-end ratebase going into an IRM year, THESL would have needed to propose a substantially lower amount of CAPEX from the outset.

3. <u>The OEB-approved CAPEX spending excluded from 2012 ratebase though the operation of the half year rule presents a material cost to THESL.</u> As set out in Appendix 1 to the Managers Summary of this application, the average annual foregone revenue requirement related to the excluded, approved ratebase is $12.6 million.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES ON ISSUE 1.3

INTERROGATORY 14:

Reference(s): **T2/p. 3 and 6 and *Submissions on the General Issues and the Discussion Papers from the School Energy Coalition* (EB-2010-0377/EB-2010-0378/EB-2010-0379/EB-2011-0043/p. 11**

In the first reference on page 3, THESL makes a proposal that the Board recognize in 2012 distribution rates the Board approved, actual year-end ratebase of 2011, which is materially larger than the average ratebase upon which 2011 rates were set.

On page 6 of the first reference, THESL states that "In summary, the operation of the half-year rule in THESL's circumstances would result in a permanent loss of approximately $37.9 million dollars over the balance of the IRM term, unless remedied by the Board."

In the second reference, SEC made the following comments on the half-year rule issue:

> "The problem of capital funding under IRM is a difficult one. At a simplistic level, utilities argue that the only funding in rates for new capital is the depreciation on the existing assets, but new assets cost more than old ones because of inflation. The term Capital Expenditures in Excess of Depreciation (CEEDs) has been coined to express this. These same utilities argue that the half year rule in the rebasing years builds in a further shortfall that is not recoverable under IRM.
>
> This basic argument is simply wrong. On the CEEDs issue, the argument fails to reflect the fact that while new assets do indeed cost more than old assets, the annual cost of old assets (when depreciation, cost of capital, and related PILs is

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES ON ISSUE 1.3

> totalled) is going down every year because the undepreciated capital cost is dropping, and the depreciation provision is going up annually as new assets are included."

SEC follows this argument with an example illustrating its argument.

Please provide THESL's comments on the views expressed by SEC and the example provided to illustrate it.

RESPONSE:

THESL disagrees with most of what is asserted by SEC, because of the factors explained below:

1. It confuses recovery of foregone revenue requirement with funding for future investment, by confusing the consequences of the 2011 half year rule with the funding of new capital expenditures in years subsequent to rebasing.
2. It does not recognize that a significant, OEB-approved investment has been made by THESL, but THESL is precluded by the operation of the half-year rule from recovering the revenue requirement associated with this investment.
3. It suggests incorrectly that PCI-adjusted rates provide full compensation for the increasing costs of new assets through PCI-adjusted depreciation.
4. It does not recognize that THESL must replace assets that do not now, and in some cases never did, constitute any part of ratebase or corresponding revenue requirements and rates.

THESL's concern with the half year rule, as applied in 2011, arises with respect to the lack of recovery for OEB-approved, historical CAPEX undertaken in the rebasing year

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES ON ISSUE 1.3

prior to the onset of subsequent IRM years. The OEB approved 2011 CAPEX for THESL significantly exceeding depreciation, such that 2011 year-end actual and approved ratebase significantly exceeded average ratebase upon which rates were set. Rates for 2011 covered the capital-related costs of average ratebase for 2011, not the significantly higher ratebase at year end. These capital-related costs include not only depreciation, which SEC focuses on, but also debt service costs, equity returns, and taxes payable on those equity returns.

The materiality of this problem is directly proportional to the level of CEEDs. If CEEDs are large, as was the case for THESL in 2011, the foregone revenue requirement is material.

SEC's position is that the PCI adjustment to rates in the IRM period compensates utilities for the rising cost of capital equipment. However, that is irrelevant to THESL's concern regarding the recovery of the foregone revenue requirement. SEC's analysis is incorrect because the revenue requirement associated with the unrecognized ratebase is (by definition) entirely excluded from the rates that are escalated by the PCI factor during the IRM period. So with respect to the issue of the half year rule and its effect on the recovery of historical ratebase costs, THESL does not agree with SEC's position.

With respect to depreciation as a source of funds for future investment, SEC's example is a quasi-replacement cost model of depreciation. SEC states at section 2.2.6 of the above referenced submission that "It has been demonstrated algebraically, financially, and in a full model that, if the annual increase in the cost of capital assets due to inflationary forces is exactly equal to the net increase in the X factor, the IRM formula includes in rates exactly the amount necessary to replace the assets being retired (including the

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES ON ISSUE 1.3

impact of compounding).” [THESL understands that by ‘X factor’, SEC is referring to the PCI adjustment.]

On average, depreciation represents a certain proportion of ratebase. Similarly, depreciation expense in a given year’s revenue requirement will represent a certain fraction of that revenue requirement, and a certain fraction of the corresponding rates. In SEC’s example, SEC postulates that if during the IRM period rates are escalated successively by the annual PCI factor, at the end of that time depreciation will represent the same proportion of rates as it did to begin with. This is to say that if one number is a certain fraction of another, and one multiplies both numbers successively by the same factor, at the end the proportional relationship between the two numbers will be the same. THESL agrees, since this is true by definition.

THESL agrees that during the IRM portion of the 3GIRM cycle, the allowance in rates for depreciation is escalated in a manner that could be considered similar to that of replacement cost model for depreciation.

However, THESL does not agree that successive adjustment of rates in the IRM period is fully equivalent to a replacement cost model for depreciation. The PCI factor by which rates are multiplied is a function of both inflation and the combination of the base productivity factor plus the utility specific stretch factor. In THESL’s case, the sum of the productivity and stretch factors is -1.32%. As a result, <u>the allowance for</u> depreciation in rates is escalated by an amount significantly less than inflation. More than half of the inflation factor is removed. As a result, SEC’s assumption that “the annual increase in the cost of capital assets due to inflationary forces is exactly equal to the net increase in the X factor” is never met.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES ON ISSUE 1.3

In contrast, the accounting recognition of depreciation expense in a given year is entirely determined by depreciation rates applied to the historical costs of assets. It is not a discretionary cost and it is completely insusceptible to productivity improvement. As a result, actual depreciation expense systematically exceeds the allowance for depreciation in rates.

SEC's analysis further does not recognize that under IRM, the allowance for depreciation in revenue requirement and rates is reset at rebasing to the level associated with the historical cost of the undepreciated assets in ratebase at that time.

SEC's analysis also fails to account for the fact that a significant portion of THESL's entire asset base, which is used to provide service to customers and for which THESL is responsible, has come into THESL's asset base by way of capital contributions or like mechanisms. Although these assets were originally contributed and thus have never entered ratebase or revenue requirement, (which THESL does not oppose), at end of life THESL is responsible for their replacement. Their categorical exclusion from ratebase means that their replacement cost is not reflected in the depreciation allowance in current revenue requirement, and is not escalated by PCI adjustments. Similar considerations apply to assets which continue to provide service but which are completely depreciated from an accounting standpoint, and thus do not contribute to current revenue requirement.

As a result of these factors, SEC is incorrect to conclude that PCI-adjusted depreciation implicit in rates during the IRM period compensates for actual depreciation expense and allows utilities to maintain their existing systems in a steady state.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES ON ISSUE 1.3

THESL agrees that historical ratebase attracts less revenue requirement as it depreciates. However, SEC is incorrect to suggest that THESL's (or any utility's) ratebase is shrinking when CEEDs are positive. In that case, ratebase is growing by definition due to the additions to ratebase arising from CAPEX. Except in the case where a utility invests zero in new plant, some portion of old plant is continuously replaced through investment in new plant included in ratebase at current prices, and ratebase grows or shrinks according to the balance between capital additions (CAPEX) and capital subtractions (depreciation).

RESPONSES TO ASSOCIATION OF MAJOR POWER CONSUMERS IN ONTARIO INTERROGATORIES ON ISSUE 1.3

INTERROGATORY 2:

Reference(s): **Tab 2, Page 3**

a) Please explain why THESL believes it should be exempt from the Board's current practice regarding the treatment of ratebase.

RESPONSE:

a) THESL understands this question to relate to its proposal concerning recognition of 2011 year end ratebase in rates. Please refer to THESL's response to OEB Staff interrogatory 13 (Tab 6C, Schedule 1-13).

RESPONSES TO CONSUMERS COUNCIL OF CANADA INTERROGATORIES ON ISSUE 1.3

INTERROGATORY 12:

Reference(s): **Tab 2 p. 4**

What would be the impact on the 2012 revenue requirement assuming THESL's proposal to recognize its 2011 year-end rate base in 2012 was not approved?

RESPONSE:

As provided at Appendix 1 to the Manager's Summary, THESL has calculated this impact to be $12.9 million.

RESPONSES TO CONSUMERS COUNCIL OF CANADA INTERROGATORIES ON ISSUE 1.3

INTERROGATORY 13:

Reference(s): Tab 2

Please provide the detailed capital expenditure forecast for 2011, the Board approved amounts and the actual expenditures.

RESPONSE:

a) Please see the table below. Please note that the information in the 2011 Bridge column was presented as Exhibit D, Tab 7, Schedule 1 in the EB-2010-0142 proceeding. The OEB approved the total 2011 actual capital expenditures in the said proceeding as a total amount of $378.8 million. Thus, it is presented in the table likewise as a total amount.

RESPONSES TO CONSUMERS COUNCIL OF CANADA INTERROGATORIES ON ISSUE 1.3

	2011 Actual	2011 Bridge	2011 Approved
OPERATIONAL INVESTMENTS			
Grid System Investments			
Underground System	99.0	111.5	
Overhead System	39.3	44.5	
Network System	4.8	2.9	
Stations	18.2	19.1	
Total Grid System Investments	161.4	177.9	
Reactive Work	28.6	23.3	
Customer Connections	58.2	38.6	
Customer Capital Contribution	(29.8)	(13.0)	
Externally Initiated Plant Relocations	7.8	5.7	
Capital Contributions to HONI	27.8	14.4	
Engineering Capital	23.6	23.4	
AFUDC	5.2	6.0	
Other	(4.2)	3.4	
Total Distribution Plant Capital	278.6	279.8	
CORPORATE OPERATIONAL INVESTMENTS			
Fleet &Equipment Services	11.8	10.9	
Facilities	25.3	11.8	
Other	-	2.7	
Total Corporate Operational Investments	37.1	25.4	
CUSTOMER SERVICES			
Wholesale Metering	-	3.4	
Smart Metering	10.1	8.5	
Suite Metering	10.2	4.8	
Other	0.0	1.5	
Total CUSTOMER SERVICES	20.3	18.2	
Total INFORMATION TECHNOLOGY	32.4	30.5	
Total OPERATIONAL INVESTMENTS	368.4	353.9	
CRITICAL ISSUES			
Standardization	44.6	21.7	
Downtown Contingency	4.7	-	
FESI / WPF	19.3	17.6	
Stations System Enhancements	4.7	19.9	
Secondary Upgrade	3.9	16.0	
Total CRITICAL ISSUES	77.1	75.2	
TOTAL CAPITAL	445.5	429.1	378.8

RESPONSES TO CONSUMERS COUNCIL OF CANADA INTERROGATORIES ON ISSUE 1.3

INTERROGATORY 14:

Reference(s): Tab 2 p. 5

THESL's actual expenditures in 2011 were $445.5 million in 2011, whereas Board approved expenditures were $378.8 million. How were those expenditures funded given the statement on p. 8 that, "THESL has only one source of funding for the capital related costs of its capital expenditures, which is revenue from its distribution rates."

RESPONSE:

The excess expenditures were not funded, and will not be unless and until they are included in ratebase upon THESL's next rebasing. Nevertheless, THESL has decided to commit a very substantial amount to the completion of the work identified as necessary for the reliability and safety of the system and the safety of THESL's employees.

RESPONSES TO CONSUMERS COUNCIL OF CANADA INTERROGATORIES ON ISSUE 1.3

INTERROGATORY 15:

Reference(s): **Tab 2 p. 6**

Provide the detailed calculation of the $12.6 million.

RESPONSE:

The detailed calculation is provided at Appendix 1 to the Manager's Summary.

RESPONSES TO ENERGY PROBE RESEARCH FOUNDATION INTERROGATORIES ON ISSUE 1.3

INTERROGATORY 4:

Reference(s): Manager's Summary Tab 2, Page 3

a) Please provide a schedule that shows the continuity of Rate Base for 2011-2014, including approved Opening 2011 Rate Base and 2011 Closing Rate Base.

b) Please include a breakdown of the major RB components including Gross and Net fixed Assets, CAPEX, Depreciation and Working Capital.

RESPONSE:

a) and b)

The table provided in part c) below provides the information requested for 2011. With respect to the forecasted information requested, THESL has advised the OEB and intervenors that it will be filing an update to its pre-filed evidence. THESL believes that its pending update will fundamentally affect THESL's response in respect of the forecasted information, such that providing a response now would not materially assist the OEB or intervenors. THESL accordingly defers its response in respect of the forecasted information until after its forthcoming evidentiary update.

c) Please reconcile the 2011 Rate base to the EB-2010-0142 Settlement Agreement and Board Order and to the Amount shown in the Managers Summary Appendix 2 Line 1.

RESPONSE:

c) Please see the table below.

RESPONSES TO ENERGY PROBE RESEARCH FOUNDATION INTERROGATORIES ON ISSUE 1.3

	2011 Approved	2011 Actual
CAPEX	$ 378.8	$ 445.5
GROSS FIXED ASSETS		
Opening Balance	$ 4,183.6	$ 4,179.7
Additions	$ 348.9	$ 439.1
Disposals	$ -	$ (11.1)
Closing Balance	$ 4,532.5	$ 4,607.8
ACCUMULATED DEPRECIATION		
Opening Balance	$ (2,285.7)	$ (2,283.9)
Accumulated Depreciation	$ (141.6)	$ (148.6)
Disposals	$ -	$ 8.3
Closing Balance	$ (2,427.4)	$ (2,424.2)
NET FIXED ASSETS OPENING BALANCE	$ 1,897.8	$ 1,895.8
NET FIXED ASSETS CLOSING BALANCE	$ 2,105.1	$ 2,183.5
Average NFA	$ 2,001.5	$ 2,039.7
Working Capital Allowance	$ 296.7	$ 313.6
Rate Base	$ 2,298.2	$ 2,353.2
As per Manager Summary and 2011 Decision	$ 2,298.2	n/a
Variance	$ 0.0	n/a

RESPONSES TO ENERGY PROBE RESEARCH FOUNDATION INTERROGATORIES ON ISSUE 1.3

INTERROGATORY 5:

Reference(s): Manager's Summary Tab 2, Page 3

a) Please provide the Rate Base Continuity Schedule filed in EB-2010-0142.

RESPONSE:

a) Please see the table below.

Toronto Hydro-Electric System Limited
EB-2010-0142
Exhibit D1
Tab 4
Schedule 1
ORIGINAL
Page 1 of 1

Table 1: Utility Rate Base ($ millions)

	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5
1		2009 Historical	2010 Board Approved	2010 Bridge	2011 Test
2					
3	Gross Fixed Assets (average)	$3,836.8	$4,122.7	$4,055.5	$4,404.2
4	Accumulated Depreciation (average)	($2,069.5)	($2,255.5)	($2,205.2)	($2,376.3)
5	Net Fixed Assets (average)	$1,767.3	$1,867.1	$1,850.3	$2,027.9
6					
7	Allowance for Working Capital	$266.8	$273.6	$277.4	$318.4
8					
9	Total Rate Base	$2,034.1	$2,140.7	$2,127.7	$2,346.3

b) What did the Settlement Agreement in EB-2010-0142 contemplate with regard to Opening/Closing and Average Rate Base? Provide the figures and words from the Settlement related to 2011 CAPEX and Total Rate Base.

RESPONSE:

b) Please see the attached Appendix A.

RESPONSES TO ENERGY PROBE RESEARCH FOUNDATION INTERROGATORIES ON ISSUE 1.3

c) Please provide the relevant extracts from the Board's Decision and Rate Order in EB-2010-0142 regarding THESL's 2011 approved Rate Base and CAPEX.

RESPONSE:

c) Please see the attached Appendix B.

Complete Settlement: For the purposes of settlement of the issues in this proceeding, the intervenors accept the proposed amounts for capital and property taxes, as adjusted to reflect the Accounting Update and this settlement.

Evidence: Exhibit H1, Tab 1; Exhibit R1, Tab 3, Schedule 42.

Supporting parties: THESL, AMPCO, BOMA, CCC, Energy Probe, SEC, and VECC.

Parties taking no position: PP and SSMWG

3.7 Is the amount proposed for PILs, including the methodology, appropriate?

Complete Settlement: For the purposes of settlement of the issues in this proceeding, the intervenors accept the amount proposed for PILS, as adjusted to reflect the Accounting Update and this settlement.

Evidence: Exhibit H1, Tab 1; Exhibit Q1, Tab 2; Exhibit R1, Tab 1, Schedule 57-58; Exhibit R1, Tab 3, Schedule 42, 53, 55.

Supporting parties: THESL, AMPCO, BOMA, CCC, Energy Probe, SEC, and VECC.

Parties taking no position: PP and SSMWG

4. CAPITAL EXPENDITURES AND RATE BASE

4.1 Are the amounts proposed for Rate Base appropriate?

Partial Settlement: For the purposes of settlement of the issues in this proceeding, the parties agree to the revised amounts proposed for Rate Base as set forth in Appendix B, subject to the Board's determination with respect to the emerging requirements which were identified in Procedural Order No. 4 as not being eligible for settlement.

Evidence: Exhibits D1, Tab 1-15; Exhibit D2, Tab 1; Exhibit R1, Tab 4, Schedule 16, 28-29; Exhibit R1, Tab 9, Schedule 46.

Supporting parties: THESL, AMPCO, BOMA, CCC, Energy Probe, SEC, and VECC.

Parties taking no position: PP and SSMWG

4.2 Are the amounts proposed for 2011 Capital Expenditures appropriate including the specific Operational and Emerging Requirements categories?

Partial Settlement: As part of this settlement proposal, THESL agrees to reduce its 2011 capital budget from $498M originally requested in the Application to

$378.8M, which amount reflects the Accounting Update adjustments and excludes the Emerging Requirements which were identified in Procedural Order No. 4 as not eligible for settlement..

THESL agrees that, based on this agreed capital budget, it can continue to operate its system in a safe and reliable manner in the Test Year. All of the parties agree that the scope of this issue can therefore be reduced to:

> "Are the amounts proposed for 2011 Capital Expenditures related to (i) the energy storage project included under emerging requirements, (ii) the electric vehicle charging infrastructure program included under smart grid as part of emerging requirements; and (iii) the vehicle purchases related to the green initiative under the general plant category (the "**Emerging Requirements**") appropriate?"

Evidence: Exhibits D1, Tab 7-9; Exhibit R1, Tab 1, Schedule 18, 61-63, 66-71, 74-81; Exhibit R1, Tab 2, Schedule 21-25; Exhibit R1, Tab 3, Schedule 6-31; Exhibit R1, Tab 04, Schedule 31**;** Exhibit R1, Tab 6, Schedule 1; Exhibit R1, Tab 9, Schedule 46-47, 49-55; Exhibit S1, Tab 1, Schedule 13-15; Exhibit S1, Tab 3, Schedule 3; Exhibit R2, Tab 1, Schedule 11; Exhibit R2, Tab 5, Schedule 1; Exhibit S2, Tab 1, Schedule 9.

Supporting parties: THESL, AMPCO, BOMA, CCC, Energy Probe, SEC, and VECC.

Parties taking no position: PP and SSMWG

4.3 Are the inputs used to determine the Working Capital component of the Rate Base appropriate and is the methodology used appropriate?

Complete Settlement: . See Issue 4.1 above.

Evidence: Exhibit D1, Tab 14; Exhibit R1, Tab 1, Schedule 79; Exhibit S1, Tab 7, Schedule 20.

Supporting parties: THESL, AMPCO, BOMA, CCC, Energy Probe, SEC, and VECC.

Parties taking no position: PP and SSMWG

4.4 Does Toronto Hydro's Asset Condition Assessment information and Investment Planning Process adequately address the condition of the distribution system assets and support the O&MA and Capital expenditures for 2011?

Complete Settlement: The parties agree that THESL's Asset Condition Assessment and Investment Planning Process and the other evidence provided by THESL in this proceeding collectively support the net capital budget in the Test Year of $378.7 million.

additional information recorded in this settlement proposal, is sufficient in the context of the overall settlement to support the proposed settlement or partial settlement. There are Appendices to this settlement proposal which provide further support for the proposed settlement.

Pursuant to Procedural Order #4, the Board determined that the $30 million energy storage project proposed by THESL could not be settled, but would go to a hearing. Contemporaneously with this Settlement Agreement, THESL has written to the Board withdrawing its application for approval of that project. In entering into this Agreement, the parties have assumed that the withdrawal of the energy storage project is accepted by the Board. All calculations of OM&A, capital, rate base, revenue requirement, and other such amounts are based on that assumption.

According to the *Guidelines* (p. 3), the parties must consider whether a settlement proposal should include an appropriate adjustment mechanism for any settled issue that may be affected by external factors. The parties consider that no settled issue requires a specific adjustment mechanism. The settlement on each of the issues may, however, be subject to adjustment for the impacts of the Board's determination on the unsettled issues, as further described below.

The parties have settled the issues as a package and none of the parts of this settlement proposal is severable. If the Board does not accept this settlement proposal, in its entirety, then there is no settlement (unless the parties agree in writing that any part(s) of this settlement proposal that the Board does accept may continue as a valid settlement without inclusion of any part(s) that the Board does not accept).

It is also agreed that this Agreement is without prejudice to any of the Parties re-examining these issues in any subsequent proceeding and taking positions inconsistent with the resolution of these issues in this Agreement. However, none of the Parties will in any subsequent proceeding take the position that the resolution therein of any issue settled in this Agreement, if contrary to the terms of this Agreement, should be applicable for all or any part of the 2011 Test Year.

Summary of the Settlement

The central feature of this settlement proposal is an agreed-to decrease in THESL's proposed 2011 Base Revenue Requirement from $578.4M, as proposed in the Application, to $524.8M in this settlement proposal, which includes adjustments arising out of the Accounting Update, as discussed below, subject to the Board's determination of the unsettled issues. This settlement is pending updated revenue requirement and rate impacts reflecting the cost of capital parameters defined in the Board's March 3, 2011 letter for distributors that are applying for May 1st 2011 rates which will be provided on Monday, March 28, 2011. The expected impact of the adjustment is approximately $3M reduction in revenue requirement.

This reduced Revenue Requirement corresponds to the following changes in capital and operational expenditures, which changes are more fully explained in the applicable section of this settlement agreement:

($ million)	Application	Settlement Proposal [(1)]	Settlement Proposal [(2)]	Relevant Issue
2011 Base Revenue Requirement	$578.4	$551.0	$524.8	1.4
2011 Capital Expenditures	$498.0	$400.0	$378.8	4.2
2011 OM&A	$226.8	$216.0	$237.8	3.1
2011 Revenue Offsets	$19.7	$26.0	$26.0	2.2

Notes:
(1) These settlement amounts are calculated prior to taking into account the Accounting Update adjustments. These values are included for ease of comparison only.
(2) These settlement amounts are calculated after taking into account the Accounting Update adjustments. These values form the basis of the settlement in this proposal.

The Parties believe that the Agreement represents a balanced proposal that protects the interests of Toronto Hydro's customers, employees and shareholder and promotes economic efficiency and cost effectiveness. It also provides the resources which will allow Toronto Hydro to manage its assets so that reasonable standards of performance and the safe, reliable delivery of electricity, at reasonable prices, are achieved.

This Agreement will allow Toronto Hydro to continue to make the necessary maintenance and operation expenditures as well as capital investments to maintain the safety and reliability of the electricity distribution service that it provides. This Agreement will also allow Toronto Hydro to maintain current capital investment levels in infrastructure to ensure a reliable distribution system; to manage current staffing levels, skills and training to ensure regulatory compliance with Codes and Regulations;; and to continue to provide the high level of customer service Toronto Hydro customers have come to expect.

The Accounting Update

On January 26, 2011, THESL filed a letter with the Board asking to adjourn settlement discussions so that THESL could file the Accounting Update.

On February 9, 2011, THESL filed the Accounting Update which, in short, relates to material changes to accounting estimates that THESL proposes to apply prospectively,

REVENUE REQUIREMENT WORK FORM

Version: 2.11

Name of LDC: Toronto Hydro-Electric System Limited
File Number: EB-2010-0142
Rate Year: 2011

Ontario

Rate Base

Line No.	Particulars		Initial Application	Adjustments	Settlement Agreement	Adjustments	Per Board Decision
1	Gross Fixed Assets (average)	(3)	$4,404,200,772	($46,167,599)	$4,358,033,172	$ -	$4,358,033,172
2	Accumulated Depreciation (average)	(3)	($2,376,268,969)	$19,723,763	($2,356,545,206)	$ -	($2,356,545,206)
3	Net Fixed Assets (average)	(3)	$2,027,931,803	($26,443,836)	$2,001,487,967	$ -	$2,001,487,967
4	Allowance for Working Capital	(1)	$318,391,990	($21,684,337)	$296,707,652	$ -	$296,707,652
5	**Total Rate Base**		$2,346,323,793	($48,128,174)	$2,298,195,619	$ -	$2,298,195,619

Line No.	(1) Allowance for Working Capital - Derivation		Initial Application	Adjustments		Settlement Agreement	Adjustments	Per Board Decision
6	Controllable Expenses		$226,817,269	$10,999,337		$237,816,606	$ -	$237,816,606
7	Cost of Power		$2,242,116,161	($180,000)		$2,241,936,161	$ -	$2,241,936,161
8	Working Capital Base		$2,468,933,430	$10,819,337		$2,479,752,766	$ -	$2,479,752,766
9	Working Capital Rate %	(2)	12.90%	-0.93%	a	11.97%	0.00%	11.97%
10	Working Capital Allowance		$318,391,990	($21,684,337)		$296,707,652	$ -	$296,707,652

Notes

(2) Generally 15%. Some distributors may have a unique rate due as a result of a lead-lag study.
(3) Average of opening and closing balances for the year.

Ontario Energy Board

Commission de l'énergie de l'Ontario

Ontario

EB-2010-0142

IN THE MATTER OF the *Ontario Energy Board Act, 1998*, S.O. 1998, c. 15, (Schedule B);

AND IN THE MATTER OF an application by Toronto Hydro-Electric System Limited for an order approving just and reasonable rates and other charges for electricity distribution to be effective May 1, 2011.

BEFORE: Ken Quesnelle
Presiding Member

Marika Hare
Member

Karen Taylor
Member

RATE ORDER

Toronto Hydro-Electric System Limited ("Toronto Hydro", or the "Applicant") filed an application, dated August 23, 2010, with the Ontario Energy Board under section 78 of the *Ontario Energy Board Act, S.O. 1998*, c.15, Schedule B, for an order or orders approving just and reasonable rates and charges for the rate year commencing May 1, 2011.

The Board issued its Decision on the application on July 7, 2011. In the Decision, the Board ordered the Applicant to file a draft Rate Order reflecting the Board's findings in the Decision. The Board approved an implementation date of August 1, 2011 and an effective date of May 1, 2011.

The Applicant filed a draft Rate Order ("DRO") and supporting material on July 14, 2011. Intervenor comments on the DRO were due by July 18, 2011 and were received from the Vulnerable Energy Consumers Coalition ("VECC"), the Building Owners and Managers Association of the Greater Toronto Area ("BOMA") and the Association of Major Power Consumers in Ontario ("AMPCO").

VECC stated that it had reviewed the DRO and its only concern was with respect to the Revenue to Cost ratio adjustments made by Toronto Hydro. VECC observed that the reduction of the Large User revenue/cost ratio to 115% led to a revenue shortfall of roughly $300,000 which Toronto Hydro had chosen to recover from the residential class.

VECC argued that this was inappropriate as the starting revenue/cost ratio for the residential class is 88.7%, which is greater than that for either the Streetlighting or USL classes. VECC, therefore, submitted that this amount should be recovered from the Streetlighting class. BOMA supported VECC's position. AMPCO stated its support for reducing the Large User revenue-to-cost ratio so that it would fall within the Board's guidelines.

In its reply submission, Toronto Hydro expressed its disagreement with VECC's position stating that it had allocated the revenue responsibility of the Large User class to the Residential class, as this class would be the least affected on a per class and per customer basis, while both the USL and Streetlighting classes would see a much larger increase both on a per class and per customer basis if the shortfall was allocated to them.

On July 21, 2011, the Board issued its Decision on Draft Rate Order ("DDRO") which determined that Toronto Hydro should allocate the $300,000 amount to the customer classes in accordance with the Board's cost allocation policy. Toronto Hydro was directed to file an updated draft rate order attaching an updated Tariff of Rates and Charges reflecting the Board's DDRO findings by Monday July 25, 2011. The Board stated that once it had confirmed Toronto Hydro's calculations, the Board would issue a final Rate Order.

On July 22, 2011, Toronto Hydro filed a revised Draft Rate Order for 2011 Rates reflecting the Board's DDRO. On July 25, 2011 and July 26, 2011 the Board received correspondence from BOMA and VECC, respectively seeking clarification of the Board's Cost Allocation Policy as it related to the Board's finding in the DDRO. The Board notes that its decision on this issue is based on the particular facts and circumstances in this case.

The Board has reviewed the information provided in support of the revised Draft Rate Order and the proposed Tariff of Rates and Charges. The Board is satisfied that the Tariff of Rates and Charges filed accurately reflects the Board's Decision.

THE BOARD ORDERS THAT:

1. The Tariff of Rates and Charges set out in Appendix "A" of this Rate Order is approved effective May 1, 2011 for electricity consumed or estimated to have been consumed on and after such date.

2. The Tariff of Rates and Charges set out in Appendix "A" of this Order supersedes all previous Tariff of Rates and Charges approved by the Ontario Energy Board for the Toronto Hydro-Electric System Limited service area, and is final in all respects except for the stand by rates which remain interim.

3. Toronto Hydro-Electric System Limited shall notify its customers of the rate changes no later than with the first bill reflecting the new rates.

DATED at Toronto, July 28, 2011

ONTARIO ENERGY BOARD

Original Signed By

Kirsten Walli
Board Secretary

Toronto Hydro-Electric System Limited
14 Carlton Street
Toronto, Ontario M5B 1K5

Telephone: 416-542-2517
Facsimile: 416-542-3024
gwinn@torontohydro.com

TORONTO HYDRO

July 22, 2011

via RESS e-filing – signed original to follow by courier

Ms. Kirsten Walli
Board Secretary
Ontario Energy Board
PO Box 2319
2300 Yonge Street, 27th floor
Toronto, ON M4P 1E4

Dear Ms. Walli:

**Re: Toronto Hydro-Electric System Limited's ("THESL")
2011 Electricity Distribution Rates Application – Draft Rate Order ("DRO")
OEB File No. EB-2010-0142**

Please find attached THESL's revised DRO, reflecting the Board's Decision on the DRO submitted on July 21, 2011.

Should you have any questions or concerns on this matter, please contact me at 416-542-2517.

Yours truly,

[original signed by]

Glen A. Winn
Manager, Regulatory Applications & Compliance

:GAW/acc

cc: J. Mark Rodger, Counsel for THESL, by electronic mail only
Intervenors of Record for EB-2010-0142, by electronic mail only

Toronto Hydro-Electric System Limited

EB-2010-0142

Revised Draft Rate Order for 2011 Rates

Introduction

On August 23, 2010 Toronto Hydro-Electric System Limited ("THESL") filed a rate application with the Ontario Energy Board ("Board") for distribution rates to be effective for 12 months beginning May 1, 2011 (the "Application"). On March 25, 2011 THESL filed a Settlement Proposal with the Board in connection with the Application. The positions of the Parties to the Settlement Proposal reflected substantial agreement on 29 of the 34 issues on the Approved Issues List with complete settlement on 23 issues, partial settlement on six issues, and no settlement on five issues. The unsettled issues were limited to the manner of regulation that would apply to THESL, expenditures relating to greening the fleet, expenditures related to electric vehicle ("EV") charging stations, clearance of deferral accounts, and cost allocation and rate design matters. It was agreed by the Parties that all issues accepted in the Settlement Proposal were subject to any adjustments that would arise from the Board's decision on the unsettled issues.

On March 29, 2011 at the commencement of the oral hearing, the Board accepted the Settlement Proposal. On July 7, 2011 the Board issued its Partial Decision and Order in the proceeding, (the "Decision"). In the Decision, the Board ordered THESL to file a Draft Rate Order ("DRO") reflecting the Board's findings in the Decision. The Board also approved an implementation date of August 1, 2011 and an effective date of May 1, 2011. On July 14, 2011, THESL filed a DRO and supporting material, in accordance with the Decision. Intervenor comments on the DRO were filed therafter. THESL's response to Intervenor comments was filed on July 19, 2011. On July 21, 2011 the Board issued a Decision on the DRO.

THESL submits that this revised DRO complies with the direction given in the Board's Decision and properly reflects the Board's Order.

Derivation of Service and Base Distribution Revenue Requirements

THESL has completed the Revenue requirement Work Form using the approved amounts from the Decision (Appendix A). The Work Form generally sets out the derivation of the revenue requirement showing the amounts in the Application, and adjustments as per the Settlement Proposal and the Board's Decision. The adjustments noted below are those made relative to the Settlement Proposal amounts as provided for in the Decision.

Rate Base

2011 Net Fixed Assets

The net fixed assets of $2,001.5 million provided for in the Settlement Proposal remain unaffected by the Decision.

Working Capital

The working capital allowance for 2011 is $296.74 million, an increase of $0.03 million from the $296.71 accepted in the Settlement Proposal. This is a result of the increase in OM&A of $0.2 million for research on the impact of electric vehicle charging on the distribution system.

Total Rate Base

The Total Rate Base for 2011 is therefore $2,298.23 million, as compared to $2,298.20 million in THESL's Settlement Proposal.

Operating, Maintenance and Administration and General ("OM&A") Expenses

As noted earlier, the Board's Decision increased the OM&A component of THESL's Revenue Requirement from $237.8 million, as accepted in the Settlement Proposal, to $238.0 million, to account for an additional $0.2 million for research on the impact of electric vehicle charging on the distribution system.

Depreciation and Amortization Expense

The 2011 depreciation expense of $138.8 million remains unaffected by the Decision.

PILs

THESL's 2011 PILs is $11.8 million, which increased by a negligible amount of $862 as a result of changes to working capital and rate base.

Cost of Capital

THESL 2011 Cost of Capital is $159.4 million, which increased by a negligible amount of $2,197 as a result of changes to working capital and rate base. The cost of capital parameters (i.e., Return on Equity, Short- and Long-Term debt rates) are set according to the Board's Cost of Capital guidelines.

Service Revenue Requirement

The Decision results in an increase to the Service Revenue Requirement of $0.2 million, from $547.9 million as reflected in the Settlement Agreement, to $548.1 million.

REVENUE REQUIREMENT WORK FORM

Ontario

Name of LDC: Toronto Hydro-Electric System Limited
File Number: EB-2010-0142
Rate Year: 2011

Version: 2.11

Rate Base

Line No.	Particulars		Initial Application	Adjustments	Settlement Agreement	Adjustments	Per Board Decision
1	Gross Fixed Assets (average)	(3)	$4,404,200,772	($46,167,599)	$4,358,033,172	$ -	$4,358,033,172
2	Accumulated Depreciation (average)	(3)	($2,376,268,969)	$19,723,763	($2,356,545,206)	$ -	($2,356,545,206)
3	Net Fixed Assets (average)	(3)	$2,027,931,803	($26,443,836)	$2,001,487,967	$ -	$2,001,487,967
4	Allowance for Working Capital	(1)	$318,391,990	($21,684,337)	$296,707,652	$31,662	$296,739,314
5	**Total Rate Base**		$2,346,323,793	($48,128,174)	$2,298,195,619	$31,662	$2,298,227,281

Line No.	(1) Allowance for Working Capital - Derivation		Initial Application	Adjustments	Settlement Agreement	Adjustments	Per Board Decision
6	Controllable Expenses		$226,817,269	$10,999,337	$237,816,606	$200,000	$238,016,606
7	Cost of Power		$2,242,116,161	###########	$2,066,268,287	$ -	$2,066,268,287
8	Working Capital Base		$2,468,933,430	###########	$2,304,084,893	$200,000	$2,304,284,893
9	Working Capital Rate %	(2)	12.90%	-0.02% a	12.88%	0.00%	12.88%
10	Working Capital Allowance		$318,391,990	($21,684,337)	$296,707,652	$31,662	$296,739,314

Notes
(2) Generally 15%. Some distributors may have a unique rate due as a result of a lead-lag study.
(3) Average of opening and closing balances for the year.

RESPONSES TO ENERGY PROBE RESEARCH FOUNDATION INTERROGATORIES ON ISSUE 1.3

INTERROGATORY 6:

Reference(s): Manager's Summary Tab 2, Page 4

a) Please provide a continuity schedule for 2011A, 2012 YTD and 2012 E and 2013-2015 F showing CAPEX and Rate Base.

b) Please reconcile to Gross and Net fixed assets in the Spreadsheet "Incremental Capital Proj. Wksheet 20120510".

RESPONSE:

a) and b) THESL has advised the OEB and intervenors that it will be filing an update to its pre-filed evidence. THESL believes that its pending update will fundamentally affect THESL's response to this interrogatory, such that providing a response now would not materially assist the OEB or intervenors. THESL accordingly defers its response in respect of this interrogatory until after its forthcoming evidentiary update.

RESPONSES TO ENERGY PROBE RESEARCH FOUNDATION INTERROGATORIES ON ISSUE 1.3

INTERROGATORY 7:

Reference(s): Managers Summary Tab 2, Appendix 1, Page 1

a) Please provide the ICM DRR Calculations in Active Excel Spreadsheet format. Please list all input assumptions and sources of data for each line as needed (e.g. cost of capital, interest).

RESPONSE:

a) The noted reference is to THESL's exhibit which calculates the revenue requirement and resulting rate riders associated with recognition of 2011 approved year-end ratebase, not the ICM rate adders. A corrected version of Appendix 1 in electronic format is provided. Please note that the following corrections have been made to Appendix 1:

   1) On page 1, the calculation of the interest component of return has been corrected to use the average balance instead of the closing balance; and
   2) On pages 2-4, the percentage of revenues by rate class and billing unit have been corrected for an incorrect value used for the Competitive Sector Multi-Unit Residential class and transposition of the customer and connection charges for the USL class.

b) Confirm the calculated ICM distribution revenue requirements are based on the 2011 <u>average</u> Rate Base and OEB rules regarding ICM threshold and dead band. If not, also provide a version that does and discuss the differences.

RESPONSES TO ENERGY PROBE RESEARCH FOUNDATION INTERROGATORIES ON ISSUE 1.3

RESPONSE:

b) THESL confirms that the calculation of the revenue requirements (and rate riders) associated with the recognition of approved year-end ratebase (not the ICM rate adders) does use the average of the unrecognized ratebase. However, THESL submits that the ICM threshold and deadband are not relevant to this proposed recovery and corresponding rate riders.

RESPONSES TO ENERGY PROBE RESEARCH FOUNDATION INTERROGATORIES ON ISSUE 1.3

INTERROGATORY 8:

Reference(s): **Managers Summary Tab 2, Page 23, Table 3 and Appendix 1, Page 1 and Tab 4, Schedule A, Appendix 1, Page 1**

Please provide a Schedule that shows the calculations starting from the threshold amounts to the CAPEX amounts in Table 3 and the second reference -448.74 m 534.48m 439.47m; total 1,422.70 m.

RESPONSE:

Table 3 in Tab 2, Page 23 depicts the annual capital amounts proposed by THESL under the EB-2011-0144 application versus the present application, as well as the annual differences between those amounts. The capital amounts proposed in this application and depicted at the second reference are not derived from the ICM threshold and there are no calculations linking the two.

RESPONSES TO ENERGY PROBE RESEARCH FOUNDATION INTERROGATORIES ON ISSUE 1.3

INTERROGATORY 9:

Reference(s): **Managers Summary Tab 2, Appendix 1, Pages 2 and 3**

a) Please provide the 2011 Rate Rider Calculations in Active Excel Spreadsheet format.

RESPONSE:

a) Please see the response to EP interrogatory 7a (Tab 6C, Schedule 7-7, part a).

b) Please confirm that the total 2012 rate rider amount of 12,934,857.07 (N) is based on the proposed closing 2011 Rate Base, not the average 2011 Rate Base.

RESPONSE:

b) Please see response to EP interrogatory 7a (Tab 6C, Schedule 7-7, part a).

RESPONSES TO ENERGY PROBE RESEARCH FOUNDATION INTERROGATORIES ON ISSUE 1.3

INTERROGATORY 10:

Reference(s): **Managers Summary Tab 2, Page 8 &**
EB-2010-0142 Exhibit B1, Tab 7, Schedule 1, Appendix A
Corrected: 2010 Nov 8, Proforma statement of cash Flows

THESL indicates that "The only source of funds available to THESL to cover the cost of the investment is revenue through distribution rates".

Please provide a proforma Statement of Cash Flows 2011-2014 in the same format as the second reference.

RESPONSE:

2011 actual Statement of Cash Flow presented below.

THESL has advised the OEB and intervenors that it will be filing an update to its pre-filed evidence. THESL believes that its pending update will fundamentally affect THESL's response to this interrogatory, such that providing any further response now would not materially assist the OEB or intervenors. THESL accordingly defers its response in respect of the requested forecasted information until after its forthcoming evidentiary update.

RESPONSES TO ENERGY PROBE RESEARCH FOUNDATION INTERROGATORIES ON ISSUE 1.3

Pro Forma Cash Flow Statement
THESL Pro forma - Regulated

Consolidated Statements of Cash Flows As at December 31	Actual 2011 THESR
Net income for the period	94.6
Adjustments for non-cash items	
Depreciation and amortization	146.4
Net change in other assets and liabilities	(1.5)
Payments in lieu of corporate taxes	(6.2)
Post-employment benefits	9.6
Future Income taxes	0.3
Gain on disposal of property plant and equipment	(3.9)
Changes in non-cash working capital balances	
Decrease (increase) in accounts receivable	(6.8)
Decrease (increase) in unbilled revenue	20.9
Increase (decrease) in current assets	0.0
Increase (decrease) in current liabilities	38.4
Net cash provided by operating activities	**291.7**
Investing activities	
Purchase of property, plant, eq. and intangibles	(425.9)
Net change in regulatory assets and liabilities	(31.7)
Proceeds from sale of assets	5.0
Net cash used in investing activities	**(452.6)**
Financing activities	
Increase in notes payables and debentures	53.0
Increase (decrease) in customers' advance dep.	(8.2)
Net cash provided by (used in) financing activities	**44.8**
Net increase (decrease) in cash and equivalents during the period	**(116.1)**
Cash and cash equivalents, beginning of period	175.51
Cash and cash equivalents, end of period	**59.4**

RESPONSES TO SCHOOL ENERGY COALITION INTERROGATORIES ON ISSUE 1.3

INTERROGATORY 1:

Reference(s): none provided

Please provide a copy of the Applicant's:

a) Latest Annual Report

RESPONSE:

a) Please see the attached Appendix A for the Annual Report of Toronto Hydro Corporation.

b) 2012 Quarterly Financial Statements and MD&As

RESPONSE:

b) Please see the attached Appendices B and C for the Q1 2012 Quarterly Financial Statements and MD&As of Toronto Hydro Corporation, respectively; and Appendices D and E for the Q2 2012 Quarterly Financial Statements and MD&As of Toronto Hydro Corporation, respectively.

c) All 2012 Rating Agency Reports

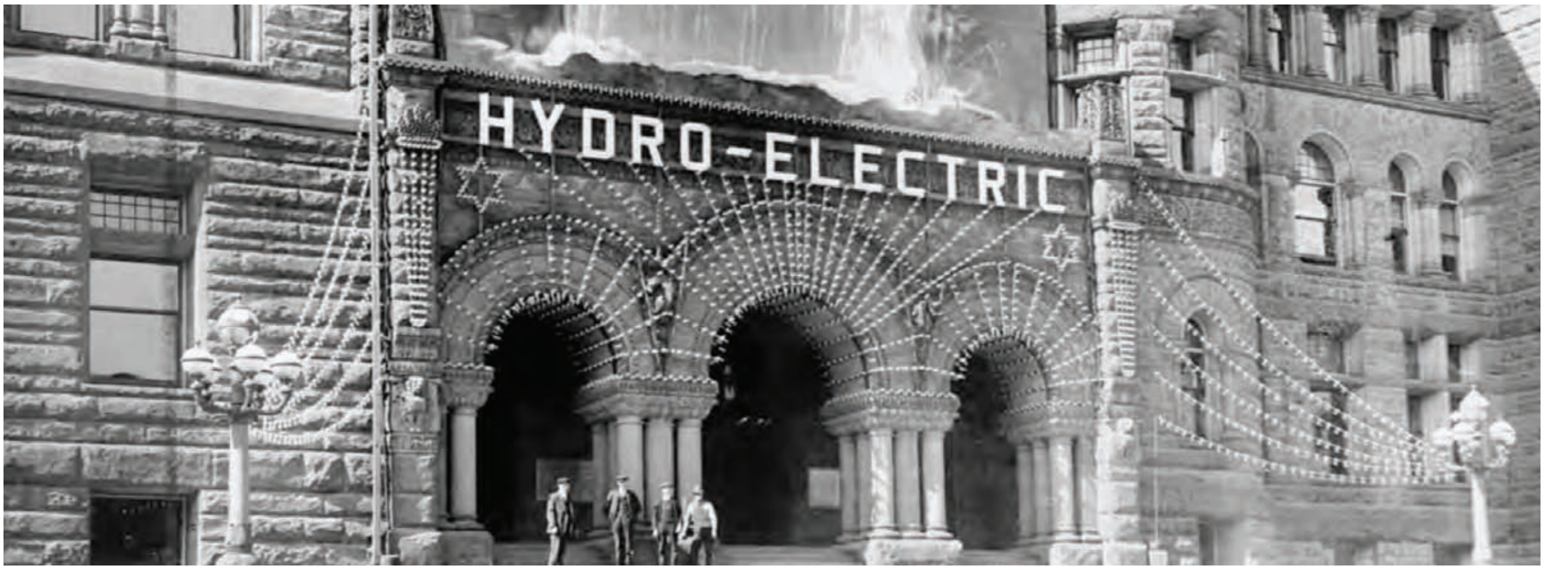
RESPONSE:

c) Please see the attached Appendices F to I (Toronto Hydro Corporation).

Toronto Hydro-Electric System Limited
EB-2012-0064
Tab 6C
Schedule 10-1
Appendix A
Filed: 2012 Oct 5
(96 pages)

2011 Annual Report

THE MEASURE OF OUR COMMITMENT



TORONTO HYDRO CORPORATION 2011 ANNUAL REPORT

TORONTO HYDRO Corporation

MESSAGE from the Chairman of the Board, and President and Chief Executive Officer

In 2011, Toronto Hydro Corporation (the "Corporation") celebrated its 100th anniversary by delivering extraordinary financial results and completing the largest capital construction program to date – safely and efficiently.

Capital expenditures totalled $437.1 million and were primarily related to the investment in electricity distribution assets in connection with our electricity distribution subsidiary's infrastructure renewal program, approved by the Ontario Energy Board ("OEB").

Impressively, we met or exceeded 90 percent of the targets on our corporate scorecard. The corporate scorecard represents key areas of our operations that are tracked by the Corporation. In achieving these outstanding results, our workforce reached a new safety milestone, logging two million hours of work without a lost time injury. This is all the more notable considering that we have been integrating new electrical trades apprentices into our workforce as part of our strategic workforce renewal program.

The Corporation's net income was $95.9 million in 2011, compared to $66.1 million in 2010. As at December 31, 2011, the Corporation and the debentures issued under its medium-term note program were rated "A (high)" by DBRS Limited and "A" by Standard & Poor's. We remain a strong investment-grade company.

On November 18, 2011, the Corporation issued $300.0 million in 10-year senior unsecured debentures. The proceeds from this issuance were used to repay the $245.1 million senior unsecured debentures of the Corporation, which matured on December 30, 2011, and the balance is expected to be used for general corporate purposes.

Toronto Hydro-Electric System Limited ("Toronto Hydro"), our electricity distribution subsidiary, is the largest municipal electricity distribution company in Canada and distributes approximately 18 percent of the electricity consumed in the Province of Ontario.

MESSAGE

Customer service is a priority. We are focussed on building a strong web-based digital relationship with our residential customers and we are introducing innovative tools to help them better understand how they use electricity, and how they can manage their electricity bills. New tools, such as the *PowerLens*™ Energy Calculator, enable homeowners to compare their usage to similar homes and receive personalized energy saving recommendations.

We also launched personalized energy alerts by email to interested residential customers to let them know if their monthly consumption may exceed pre-set electricity consumption thresholds. We engaged directly with thousands of customers through our Facebook, Twitter and YouTube channels. Public information sessions were also held across the City of Toronto to directly engage with communities to increase awareness about our infrastructure renewal programs. Our outreach efforts resulted in advance notice being provided to most customers affected by planned construction projects in their neighbourhoods or businesses.

For our larger commercial and industrial customers, we have enhanced our key account management group to help ensure that their electricity service needs are met. This includes providing energy information and analysis, customized conservation and demand management programs, and access to round-the-clock information during service interruptions.

Traffic to our website continued to increase as we expanded our content related to billing and transaction capabilities. Page views increased by 24 percent on average compared to 2010, which is a trend expected to continue as we plan to bring new services online through the My Toronto Hydro customer self-service portal in 2012.

As a condition of our electricity distribution licence, the OEB has directed Toronto Hydro to achieve 1,304 gigawatt-hours of energy savings and 286 megawatts of summer peak demand savings over the period beginning January 1, 2011 through December 31, 2014. Effective January 1, 2011, Toronto Hydro entered into an agreement with the Ontario Power Authority (“OPA”) to deliver Conservation and Demand Management programs to our residential, commercial and industrial customers. These programs are fully funded by the OPA.

The Corporation takes an active role in a number of recognized industry associations and coalitions to ensure that the best interests of our customers are advanced to government, consumers groups, and other interested parties. Toronto Hydro representatives participate on the board of directors and various operations committees of the Electricity Distributors Association, the Canadian Electricity Association (“CEA”), and the Ontario Energy Network. We are a founding member of the Coalition of Large Distributors (“CLD”), which includes Horizon Utilities Corporation, Hydro Ottawa Limited, PowerStream Inc., Veridian Connections, Hydro One Inc., Union Gas Limited and Enbridge Gas Distribution Inc. Together, we serve almost all of Ontario’s electricity and natural gas consumers.

MESSAGE

Toronto Hydro Corporation was again named one of Canada's Top 100 Employers as selected by editors of the Canada's Top 100 Employers project, organized by Mediacorp Canada Inc. Toronto Hydro Corporation was also named one of Greater Toronto's Top Employers, one of Canada's Top Family-Friendly Employers and one of Canada's Greenest Employers, also organized by Mediacorp Canada Inc. and featured in *The Globe and Mail*. Toronto Hydro Corporation was recognized as one of Canada's Outstanding Employers by The Learning Partnership – one of only ten organizations across the country to receive this award. We championed youth education and health through the Toronto Science Fair, the YMCA Relay for Strong Kids, and the City of Toronto's One on One mentoring program. We are a strong supporter of United Way Toronto through our annual employee fundraising campaign and participate in the Low Income Energy Assistance Program ("LEAP"), which provides hydro bill assistance to low-income Torontonians. We supported the City of Toronto's urban forest renewal efforts and the Ontario Forestry Association, a not-for-profit organization providing forestry education programs to students and the general public, and participated in Pollution Probe's Clean Air Commute week. We have provided a link to our Corporate Responsibility Report from each web page of this Annual Report where we share more about our sustainability efforts.

In January 2012, the OEB indicated that Toronto Hydro will be required to file its request for electricity distribution rates commencing on May 1, 2012, pursuant to the incentive regulation mechanism framework. Toronto Hydro is now preparing the organization to operate effectively under this framework. We look forward to a busy and productive 2012.

Clare R. Copeland
Chairman

Anthony M. Haines
President and Chief Executive Officer

Canada's Top 100 Employers 2012

CANADA'S TOP FAMILY-FRIENDLY EMPLOYERS 2012

Greater Toronto's Top Employers 2012

2012 Canada's Greenest Employers

GOVERNANCE

Corporate Governance

The Corporation has developed sound corporate governance practices. The Corporation's Board of Directors and management believe that strong corporate governance is essential for creating shareholder value and maintaining investor confidence.

Board of Directors

The Board of Directors of the Corporation is responsible for supervising the business and affairs of the Corporation and providing strategic guidance to management. The Board of Directors of the Corporation is composed of seven independent directors and three city councillors. All directors are appointed by the sole shareholder of the Corporation. The Board of Directors has five regularly scheduled meetings each year but meets as often as is necessary to fulfill its responsibilities to the Corporation.

The Board of Directors has worked to put in place a system of corporate governance that meets the requirements of applicable Canadian Securities rules. As part of its ongoing commitment to corporate governance, the Board of Directors operates in accordance with a board mandate, and its committees operate in accordance with committee charters, which are all reviewed and approved by the Board of Directors.

The members of the Corporation's Board of Directors are introduced here. The description indicates committee and subsidiary Board of Directors' participation.

GOVERNANCE

Code of Business Conduct and Corporate Responsibility

All employees, officers and directors of Toronto Hydro are required to comply with the principles set out in the Code of Business Conduct, which was implemented by the Corporation in 2004. The Code provides for the appointment of an Ethics and Compliance Officer and establishes a direct hotline to the Ethics and Compliance Officer by which perceived violations of the principles set out in the Code may be reported, anonymously or otherwise. The Ethics and Compliance Officer reports quarterly to the Audit Committee of the Board on the nature of complaints received including those related to audit and accounting matters. Where the complaint involves the conduct of a director or officer of the Corporation, the Ethics and Compliance Officer is required to report it to the Chair of the Audit Committee, who oversees the investigation of that complaint. A copy of Toronto Hydro's Code of Business Conduct is available on our website.

Disclosure

The Board of Directors recognizes the importance of complying with all disclosure requirements applicable by Canadian Securities rules and is committed to promoting consistent disclosure practices aimed at accurate and timely disclosure of material information. To ensure consistent and appropriate disclosure practices, the Corporation has adopted a Disclosure Policy to govern the disclosure by its employees, officers and directors of material information about the Corporation and has established a Disclosure Committee composed of senior executives to assist the Chief Executive Officer and the Chief Financial Officer in making accurate, complete and timely disclosure. The composition and operation of the Disclosure Committee are established in the Disclosure Policy.

Committees

The Board of Directors believes that its ability to discharge its responsibilities is enhanced by the active participation of committees in the corporate governance process. Currently there are four committees of the Board of Directors: Corporate Governance, Audit, Compensation, and Health and Safety. Each committee meets regularly throughout the year and provides a report at meetings of the Board of Directors on material matters considered by the committee.

GOVERNANCE

Audit Committee

The Audit Committee is responsible for overseeing the adequacy and effectiveness of financial reporting, accounting systems and internal controls. The Audit Committee reviews the Corporation's quarterly and annual financial statements as well as financial statements prepared in connection with securities offerings or required by applicable regulatory authorities, reviews the audit plans of the external auditors, oversees the internal audit of the Corporation, reviews officers' personal expenses on an annual basis and recommends the external auditor for appointment by the Corporation's sole shareholder.

Corporate Governance Committee

The Corporate Governance Committee is responsible for considering and making recommendations to the Board with respect to matters relating to the corporate governance of Toronto Hydro, including board and committee composition and mandates, and guidelines for assessing the effectiveness of the Board and its committees and procedures to ensure that the Board functions independently from management.

Compensation Committee

The Compensation Committee is responsible for reviewing and assisting the Board in overseeing Toronto Hydro's compensation program.

Health and Safety Committee

The Health and Safety Committee is responsible for considering and making recommendations to the Board with respect to matters of health and safety.

BOARD OF DIRECTORS

Clare R. Copeland (Chairman)

- **Chairman**
  Toronto Hydro-Electric System Limited
- **Chairman**
  Toronto Hydro Energy Services Inc.
- **Chief Executive Officer**
  Falls Management Company
- **Former President and CEO**
  Peoples Jewellers Corp
- **Former Chair**
  Sun Media Corp.
- **Former Chair**
  Ontario Place
- **Former Chair and Executive Officer**
  OSF Inc.

Committee Membership
Member, Compensation Committee

Patricia Callon

- **Director**
  Toronto Hydro-Electric System Limited
- **Director**
  Toronto Hydro Energy Services Inc.
- **Director**
  Stakeholder Outreach & Communications
  Canadian Securities Transition Office
- **Director**
  MicroSkills Community Development Centre
- **Former Advisor**
  Ontario Securities Commission
- **Former Vice-President and Associate General Counsel**
  Canadian Imperial Bank of Commerce
- **Former Director**
  CIBC Trust Corporation, CIBC Securities Inc., CIBC Life Insurance Company Limited, CIBC Investor Services Inc. and TAL Global Asset Management Inc.

Committee Memberships
Chair, Compensation Committee
Member, Health and Safety Committee

BOARD OF DIRECTORS

Brian Chu

- **Partner**
  Bogart Robertson & Chu
- **Trustee and Vice-Chair**
  The Centennial Centre of Science and Technology (Ontario Science Centre)
- **Former Director and President**
  Laidlaw Foundation
- **Former Director**
  Apparel Industry Development Council
- **Former Chair**
  Ontario College of Art and Design
- **Former Vice-Chair**
  Centennial College of Applied Arts and Technology
- **Former Vice-Chair**
  Chinese Cultural Centre of Greater Toronto

Committee Memberships
Chair, Audit Committee
Member, Corporate Governance Committee

Derek Cowbourne

- **Former Vice-President and Chief Operating Officer**
  Independent Electricity System Operator
- **Former Chair**
  North American Electric Reliability Corporation (NERC) Operating Committee
- **Former Chair**
  Northeast Power Coordinating Council (NPCC) Reliability Coordinating Committee
- **Member**
  Institute of Corporate Directors, Institute-Certified Director, ICD.D
- **Fellow**
  Institution of Engineering & Technology
- **Member**
  Professional Engineers of Ontario

Committee Membership
Chair, Corporate Governance Committee

BOARD OF DIRECTORS

Paulette Kennedy

- **Commissioner, part-time**
  Ontario Securities Commission
- **Member, Governing Council and Business Board**
  University of Toronto
- **Chair, Audit Committee**
  University of Toronto
- **Member, External Stakeholders Advisory Committee**
  Financial Consumer Agency of Canada
- **Former Senior Vice-President and Chief Financial Officer**
  AEGON Canada Inc.
- **Former Senior Vice-President and Chief Auditor**
  Sobeys Inc.
- **Former Chief Auditor, Former Chief Accountant, Former Vice-President Finance and Actuarial**
  Sun Life Assurance Company of Canada

Committee Memberships
Member, Audit Committee
Member, Corporate Governance Committee

Shoba Khetrapal

- **Director**
  St. Joseph's Health Centre
- **Director**
  Cancer Care Ontario
- **Director**
  The Public Accountants Council
- **Former Vice-President and Chief Financial Officer**
  Weekenders International
- **Former Vice-President and Treasurer**
  Moore Corporation Ltd.
- **Former Officer**
  Canadian Pacific Limited
- **Former Advisory Member**
  Canadian Chamber of Commerce Economic Policy Committee
- **Former Director**
  Moore Group Services – Belgium, Peak Technologies Canada Ltd., Ontario Casino Corporation and other companies

Committee Memberships
Member, Audit Committee
Member, Health and Safety Committee

BOARD OF DIRECTORS

David Williams

- **Director**
  Shoppers Drug Mart Corporation
- **Director**
  Canadian Apartment Properties REIT
- **Lead Director**
  Mattamy Homes Corp.
- **Lead Director**
  Aastra Technologies Inc.
- **Former Chairman**
  Centerplate Inc
- **Former President and Chief Executive Officer**
  Workplace Safety Insurance Board
- **Former Executive Vice-President**
  George Weston Ltd.
- **Former Executive Vice-President**
  Loblaws Companies Ltd.

Committee Membership
Chair, Health and Safety Committee

Councillor Shelley Carroll

- **City Councillor**
  Ward 33 (Don Valley East)
- **Member**
  North York Community Council
- **Member**
  City of Toronto Audit Committee
- **Member**
  Economic Development Committee
- **Director**
  Design Exchange
- **Director**
  Foodshare
- **Member**
  Toronto Arts Council
- **Director**
  Toronto Atmospheric Fund
- **Director**
  Toronto Centre for the Arts

BOARD OF DIRECTORS

Councillor Josh Colle

- **City Councillor**
  Ward 15 (Eglinton-Lawrence)
- **Member**
  North York Community Council
- **Member**
  Economic Development Committee
- **Member**
  Fairbank Village Business Improvement Area
- **Member**
  Greater Toronto Marketing Alliance
- **Member**
  Oakwood Village Business Improvement Area
- **Member**
  Toronto Financial Services Alliance
- **Director**
  Toronto Zoo
- **Member**
  York-Eglinton Business Improvement Area

Councillor Ron Moeser

- **City Councillor**
  Ward 44 (Scarborough East)
- **Member**
  Scarborough Community Council
- **Member**
  Civic Appointments Committee
- **Member**
  Parks and Environment Committee
- **Former Member**
  Budget Committee 1990–2003
- **Former Chair**
  Scarborough Community Council
- **Former Chair, Finance**
  Committee Toronto Regional Conservation Authority (T.R.C.A.)
- **Former Director**
  Toronto Zoo
- **Former Director**
  Canadian National Exhibition
- **Former Member**
  City of Toronto Seniors Committees
- **Former Director**
  Centenary Hospital
- **Former Commissioner**
  Toronto Transit Commission
- **Former Member**
  Greater Toronto Area Committee
- **Former Member**
  Rouge Park Alliance

TORONTO HYDRO

BOARD OF DIRECTORS

Colum P. Bastable*

- **Chairman**
  Cushman & Wakefield Ltd.
- **Former President & Chief Executive Officer**
  Cushman & Wakefield LePage Inc.
- **Member, Independent Review Committees**
  Brandes Investment Partners & Co.
- **Board of Directors**
  YMCA of Greater Toronto
- **Member, Board of Trustees**
  Brookfield Office Properties Canada REIT
- **Past Chair, Board of Governors**
  McMaster University
- **Former President & Chief Executive Officer**
  Royal LePage Limited

Committee Memberships
Member, Audit Committee
Member, Compensation Committee

Janet Beed*

- **President and Chief Executive Officer**
  Markham Stouffville Hospital
- **Former Vice-President and Chief Operating Officer**
  University Health Network: Toronto General Hospital
- **Former Partner**
  Global Consulting Group, Deloitte Consulting
- **Member, Board of Directors**
  VentureLab, York Region
- **Member, Board of Governors**
  Character Community Foundation of York Region

Committee Membership
Member, Compensation Committee

* Member of the Board of Directors, Toronto Hydro-Electric System Limited

SENIOR MANAGEMENT TEAM

***Anthony M. Haines**[1]
President and Chief Executive Officer

Jean-Sebastien Couillard[1,2]
Chief Financial Officer

Ivano Labricciosa[2]
Vice-President, Asset Management

Ben LaPianta[2]
Vice-President, Distribution Grid Management

Ave Lethbridge[2]
Vice-President, Organizational Effectiveness and Environment, Health & Safety

Blair H. Peberdy[2]
Vice-President, Marketing, Communications and Public Affairs

Dino Priore[2]
Vice-President, Distribution Services

Chris Tyrrell[2]
Vice-President, Customer Care and Chief Conservation Officer

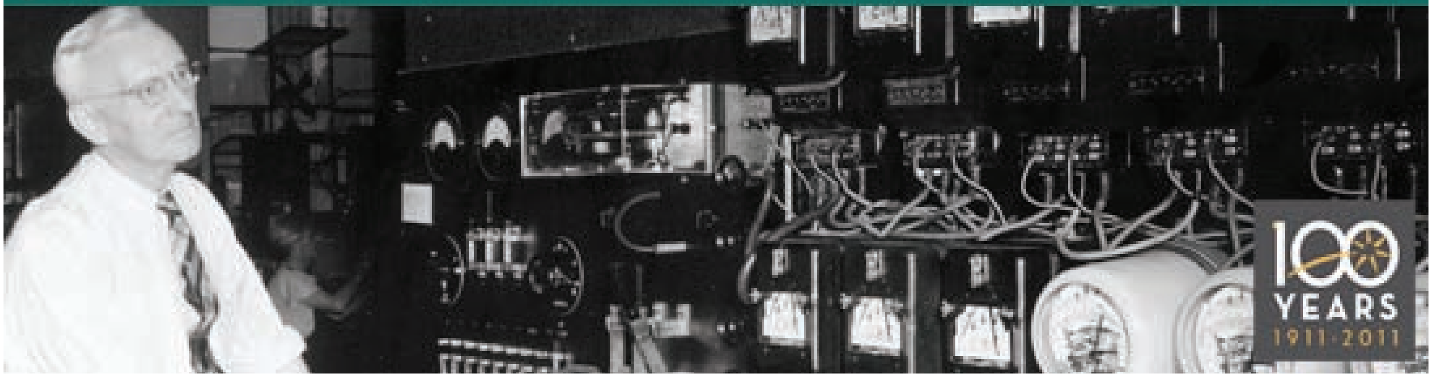
Robert Wong[2]
Vice-President, Information Technology and Strategic Management

* Also President of Toronto Hydro-Electric System Limited

[1] Toronto Hydro Corporation

[2] Toronto Hydro-Electric System Limited

OVERVIEW



TORONTO HYDRO CORPORATION

Toronto Hydro Corporation (the "Corporation") is a holding company which wholly-owns two subsidiaries:

- **Toronto Hydro-Electric System Limited – which distributes electricity and engages in conservation and demand management ("CDM") activities; and**
- **Toronto Hydro Energy Services Inc. – which provides street lighting services.**

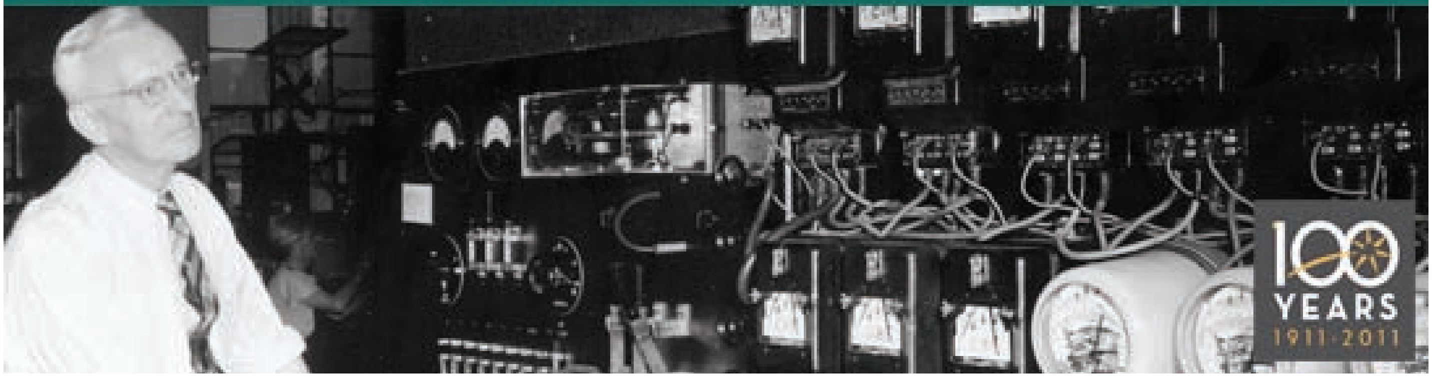
Services

- Provides policy and strategic direction to its subsidiaries.
- Manages shareholder and key business relationships.

2011 Achievements

- Celebrated the Corporation's centennial anniversary and showcased the Corporation's history with a special exhibit presented by the City of Toronto Archives and participation in Doors Open Toronto.
- Named one of **Canada's Top 100 Employers** as selected by editors of the Canada's Top 100 Employers project, organized by Mediacorp Canada Inc.; one of **Greater Toronto's Top Employers**, one of **Canada's Top Family-Friendly Employers** and one of **Canada's Greenest Employers**, also organized by Mediacorp Canada Inc. and featured in *The Globe and Mail*.
- Recognized by The Learning Partnership as one of **Canada's Outstanding Employers**.
- Raised over $400,000 for charities and community causes including United Way Toronto. Our United Way employee campaign raised over $373,000.
- Over 600 employees participated in community involvement initiatives throughout the year.
- Supported the City's Urban Forest campaign, Ontario Forestry Association and Local Enhancement and Appreciation of Forests through tree planting initiatives and forestry education programs for youth.

OVERVIEW



TORONTO HYDRO CORPORATION

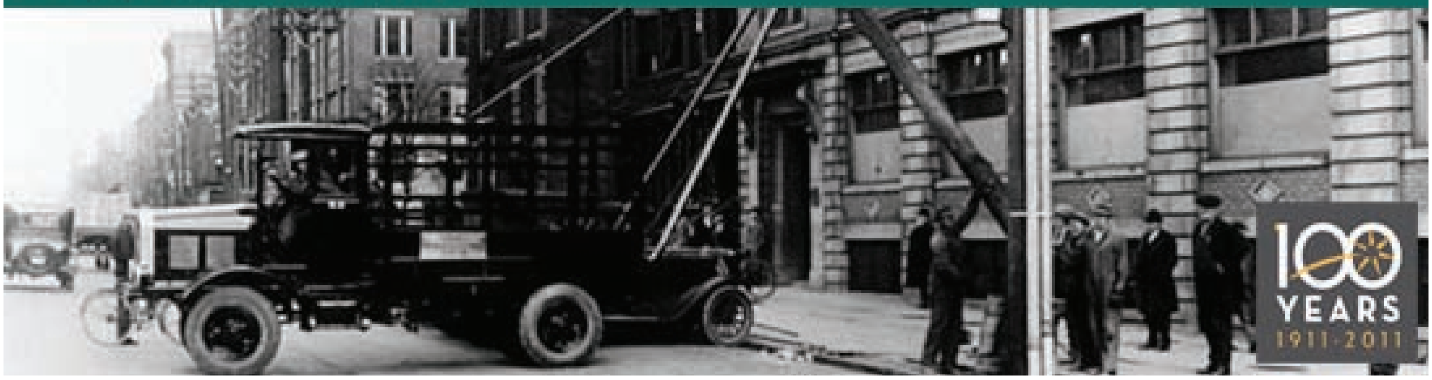
2011 Achievements (continued)

- Provided a consistent and fair return to our shareholder.
- As at December 31, 2011, the Corporation and the debentures issued under its medium-term note program were rated "A (high)" by DBRS Limited and "A" by Standard & Poor's.
- On November 18, 2011, the Corporation issued $300.0 million in 10-year senior unsecured debentures, which bear interest at the rate of 3.54% per annum and mature on November 18, 2021.

2012 Objectives

- Continue our emphasis on public safety, workplace health and safety, and corporate sustainability.
- Maintain our reputation as a premier employer with engaged and empowered employees who are proud to work for Toronto Hydro Corporation.
- Increase the value of the Corporation.

FACTS & FIGURES

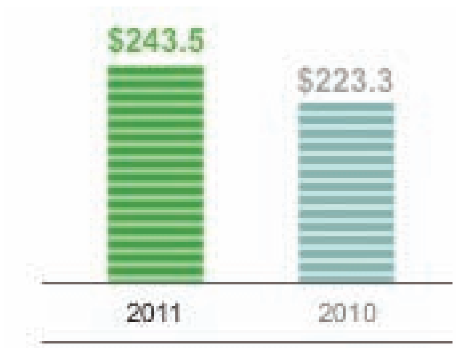


TORONTO HYDRO CORPORATION

(in millions of dollars)

Net Revenues

Operating Expenses



Capital Expenditures

TORONTO HYDRO-ELECTRIC SYSTEM LIMITED

System Average Interruption Duration Index (SAIDI)

1.43 hours

System Average Interruption Frequency Index (SAIFI)

1.62 interruptions

Customer Average Interruption Duration Index (CAIDI)

0.88 hours

Peak Load

4,919 megawatts

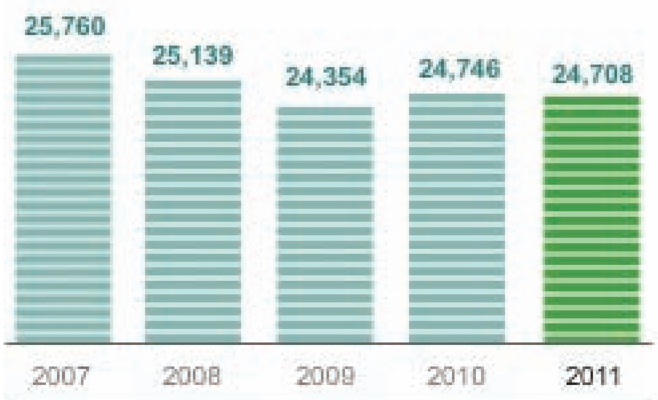
on July 21, 2011 representing approximately

18% of the provincial demand

FACTS & FIGURES

Electricity Delivered (GWh)

2011 — 24,708 GWh



Total Number of Customers

709,000
(approximate)

Residential Service	629,049
General Service with monthly demand of 0–5,000 kW	80,222
Large Users with monthly demand over 5,000 kW	52

Electricity Distributed by Class (GWh)
(approximate)

Residential	5,204
General Service	17,149
Large Users	2,355

Electricity Distributed by Class (%)
(approximate)

Residential	21%
General Service	69%
Large Users	10%

Number of Employees
(as at December 31, 2011)

1,800
(approximate)

FACTS & FIGURES

TORONTO HYDRO CORPORATION 2011 CAPITAL EXPENDITURES

(in millions of dollars)

Distribution System	$361.9
Technology Assets	33.2
Other	36.1
Non-regulated	5.9
TOTAL	**$437.1**

DISTRIBUTION SYSTEM IS SERVICED FROM:

(approximate)

35	Terminal Stations
19,800	Primary Switches
60,600	Distribution Transformers
170	In-service Municipal Substations
15,100	Kilometres of overhead wires supported by 140,600 poles and 10,900 kilometres of underground wires
1	Control Centre
7	Operations Centres

2011 ANNUAL REPORT GLOSSARY

Canadian Electricity Association ("CEA")

Customer Average Interruption Duration Index ("CAIDI")
A measure (in hours) of the average duration of interruptions experienced by customers, not including Major Event Days ("MED"). CAIDI represents the quotient obtained by dividing SAIDI by SAIFI.

Gigawatt-Hour ("GWh")
A gigawatt-hour is equal to one million kilowatt-hours.

Kilowatt ("kW")
A common measure of electrical power equal to 1,000 watts.

Kilowatt-Hour ("kWh")
A standard unit for measuring electrical energy produced or consumed over time. One kWh is the amount of electricity consumed by 10 - 100 watt light bulbs burning for one hour.

Megawatt ("MW")
A common measure of electrical power equal to one million watts.

Megawatt-Hour ("MWh")
A megawatt-hour is equal to 1,000 kilowatt-hours.

Ontario Energy Board ("OEB")

Ontario Power Authority ("OPA")

Peak Load
The maximum demand for power, measured in megawatts, that occurs within a stated period of time. Toronto Hydro's peak system load (or peak demand) normally occurs in the summer because of power demands from air conditioning.

System Average Interruption Duration Index ("SAIDI")
A measure (in hours) of the annual system average interruption duration for customers served, not including MED. SAIDI represents the quotient obtained by dividing the total customer hours of interruptions longer than one minute by the number of customers served.

2011 ANNUAL REPORT GLOSSARY

System Average Interruption Frequency Index ("SAIFI")
A measure of the frequency of service interruptions for customers served, not including MED. SAIFI represents the quotient obtained by dividing the total number of customer interruptions longer than one minute by the number of customers served.

Watt
A common measure of electrical power. One watt equals the power used when one ampere of current flows through an electrical circuit with a potential of one volt.

Watt-Hour
A measure of energy production or consumption equal to one watt produced or consumed for one hour.

TORONTO HYDRO-ELECTRIC SYSTEM LIMITED

Toronto Hydro-Electric System Limited owns and operates $2.4 billion of capital assets comprised primarily of an electricity distribution system, which delivers electricity to approximately 709,000 customers located in the City of Toronto. It is the largest municipal electricity distribution company in Canada and distributes approximately 18% of the electricity consumed in the Province of Ontario.

Services

- Delivers safe, reliable and cost-effective electrical power to approximately 709,000 residential, commercial and industrial customers in the City of Toronto, which has a population base of approximately 2.5 million.
- Plans, maintains and operates the City of Toronto's electrical distribution system infrastructure efficiently and in an environmentally responsible manner.
- Provides consistent, high-quality customer service.
- Designs and delivers electricity Conservation and Demand Management ("CDM") programs.

2011 Achievements

- Among the leading organizations in Ontario in the delivery of CDM programs to help customers conserve energy, save money and help the environment.
- Achieved savings of approximately 101,300 MWh in its conservation portfolio, bringing its total savings to approximately 885,600 MWh since the start of its programs.
- Launched a new customer care and billing system that allows for more flexibility for its users and provides an integrated billing platform leveraging the technology of the smart meters installed over the past few years.
- Launched official Facebook, YouTube and Twitter sites to better communicate with customers.
- Introduced a customer dispute resolution process to aid in the resolution of escalated customer concerns.
- Introduced a mobile driving simulator to enhance employee safe driving training.
- New website features introduced for residential and small commercial customers paying Time-of-Use ("TOU") rates; My Bill/My Alerts allows customers to easily keep track of their bills.

TORONTO HYDRO-ELECTRIC SYSTEM LIMITED

2011 Achievements (continued)

- Through a mobile planned work project, various crews are able to collect information about equipment electronically through handheld devices which helps improve safety and the quality of the asset data.
- Working together with Georgian College, we supported training programs to help drive recruitment in electrical engineering and prepare students for careers in the electricity industry.
- Supporting the Mowat Centre for Policy Innovation, School of Public Policy & Governance, University of Toronto for research on energy technology policy.
- Participating in the Centre for Urban Energy at Ryerson University, a research and technology demonstration centre devoted to the discovery and commercialization of innovative solutions to urban energy issues.
- “Beat the Peak”, an OPA funded program created to increase awareness and understanding of TOU rates was honoured with an Innovation Award from the Electricity Distributors Association in the customer service category.
- Enhanced customer service by introducing a new call back option for customers who wish to receive a call back from a customer service representative rather than staying in the hold queue.
- Through PowerUp, Toronto Hydro’s proactive maintenance and remediation program, continued to replace handwells with a non-conductive polymer concrete model in an effort to help reduce contact voltage.
- Completed a public consultation for the proposed Bremner Transformer Station and cable tunnel to help increase electricity capacity in Toronto’s downtown core.
- Launched *PowerLens*™ Energy Calculator, which provides customers with a more accurate understanding of their home energy usage.
- Working with Hydro One Inc. to refurbish the existing 115 kilovolt transmission infrastructure serving midtown to help improve service reliability.
- Invested $431.2 million in electricity distribution system equipment and related assets.
- Continued public safety campaign to remind public of electrical hazards on the street and around the home.
- Achieved 2 million hours worked without a lost time injury.

TORONTO HYDRO-ELECTRIC SYSTEM LIMITED

2012 Objectives

- Continue our focus on public and workplace safety.
- Focus on the core business of maintaining the electricity distribution system.
- Continue to implement productivity and efficiency improvements.
- Enhance customer service by increasing self-serve options.
- Maintain financial strength.
- Continue to strive to meet CDM targets under the *Green Energy Act*, 2009.

TORONTO HYDRO ENERGY SERVICES INC.

2011 Achievements

• Continued to provide reliable street lighting services to the City of Toronto.

TORONTO HYDRO
Corporation

MANAGEMENT'S DISCUSSION AND ANALYSIS
DECEMBER 31, 2011

TORONTO HYDRO CORPORATION

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS FOR THE YEAR ENDED DECEMBER 31, 2011

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Forward-Looking Information

Toronto Hydro Corporation (the "Corporation") includes forward-looking information in its Management's Discussion and Analysis ("MD&A") within the meaning of applicable securities laws in Canada ("forward-looking information"). The purpose of the forward-looking information is to provide management's expectations regarding the Corporation's future results of operations, performance, business prospects and opportunities and may not be appropriate for other purposes. All forward-looking information is given pursuant to the "safe harbour" provisions of applicable Canadian securities legislation. The words "anticipates", "believes", "budgets", "could", "estimates", "expects", "forecasts", "intends", "may", "might", "plans", "projects", "schedule", "should", "will", "would" and similar expressions are often intended to identify forward-looking information, although not all forward-looking information contains these identifying words. The forward-looking information reflects management's current beliefs and is based on information currently available to the Corporation's management.

The forward-looking information in the MD&A includes, but is not limited to, statements regarding Toronto Hydro-Electric System Limited's ("LDC") distribution revenue, the outcome of outstanding rate applications and other proceedings before the Ontario Energy Board ("OEB"), the Corporation's plans to borrow funds to repay maturing debentures and to finance the investment in LDC's infrastructure, LDC's Conservation and Demand Management ("CDM") programs, the outcome of outstanding proceedings before the Ministry of Finance of Ontario ("Ministry of Finance"), the expected results of legal proceedings, market volatility on the Corporation's consolidated results of operations, performance, business prospects and opportunities, the effect of changes in interest rates on future revenue requirements, the Corporation's conversion to United States Generally Accepted Accounting Principles ("US GAAP") and the changes in accounting estimates. The statements that make up the forward-looking information are based on assumptions that include, but are not limited to, the future course of the economy and financial markets, the receipt of applicable regulatory approvals and requested rate orders, the receipt of favourable judgments, the level of interest rates, the Corporation's ability to borrow and the expected impact of the conversion to US GAAP on the Corporation's consolidated financial statements.

The forward-looking information is subject to risks, uncertainties and other factors that could cause actual results to differ materially from historical results or results anticipated by the forward-looking information. The factors which could cause results or events to differ from current expectations include, but are not limited to, market liquidity and the quality of the underlying assets and financial instruments, the timing and extent of changes in prevailing interest rates, inflation levels, legislative, judicial and regulatory developments that could affect revenues and the results of borrowing efforts.

All forward-looking information in the MD&A is qualified in its entirety by the above cautionary statements and, except as required by law, the Corporation undertakes no obligation to revise or update any forward-looking information as a result of new information, future events or otherwise after the date hereof.

Introduction

The following MD&A should be read in conjunction with the audited consolidated financial statements and accompanying notes of the Corporation as at and for the year ended December 31, 2011 (the "Consolidated Financial Statements"). The Consolidated Financial Statements are prepared in accordance with Canadian Generally Accepted Accounting Principles ("GAAP"), including accounting principles prescribed by the OEB, and are presented in Canadian dollars (see "Significant Accounting Policies" below).

Business of Toronto Hydro

The Corporation is a holding company which wholly-owns two subsidiaries:

- *LDC* - which distributes electricity and engages in CDM activities; and
- *Toronto Hydro Energy Services Inc. ("TH Energy")* - which provides street lighting services.

The principal business of the Corporation and its subsidiaries is the distribution of electricity by LDC. LDC owns and operates an electricity distribution system, which delivers electricity to approximately 709,000 customers located in the City of Toronto (the "City"). LDC is the largest municipal electricity distribution company in Canada and distributes approximately 18% of the electricity consumed in the Province of Ontario ("Ontario"). The business of LDC is regulated by the OEB which has broad powers relating to licensing, standards of conduct and service and the regulation of electricity distribution rates charged by LDC and other electricity distributors in Ontario. See note 2 to the Consolidated Financial Statements.

The sole shareholder of the Corporation is the City.

Executive Summary

- Net income was $95.9 million in 2011 compared to $66.1 million in 2010;
- capital expenditures were $437.1 million in 2011 compared to $390.8 million in 2010, with the increase primarily related to reinforcing and maintaining the electricity distribution system of LDC;
- LDC was ordered to file its 2012 electricity distribution rate application using the incentive regulation mechanism framework;
- $300.0 million in 10-year senior unsecured debentures were issued primarily to repay the existing senior unsecured debentures which matured on December 30, 2011; and
- plans to commence reporting under US GAAP in its interim consolidated financial statements for the first quarter of 2012.

Electricity Distribution – Industry Overview

In April 1999, the government of Ontario began restructuring Ontario's electricity industry. Under regulations passed pursuant to the restructuring, LDC and other electricity distributors have been purchasing their electricity from the wholesale market administered by the Independent Electricity System Operator ("IESO") and recovering the costs of electricity and certain other costs at a later date in accordance with procedures mandated by the OEB.

The OEB has regulatory oversight of electricity matters in Ontario. The *Ontario Energy Board Act, 1998* (Ontario) (the "OEB Act") sets out the OEB's authority to issue a distribution licence which must be obtained by owners or operators of an electricity distribution system in Ontario. The OEB prescribes licence requirements and conditions including, among other things, specified accounting records, regulatory accounting principles, separation of accounts for separate businesses and filing process requirements for rate-setting purposes.

The OEB's authority and responsibilities include the power to approve and fix rates for the transmission and distribution of electricity, the power to provide continued rate protection for rural and remote electricity customers and the responsibility for ensuring that electricity distribution companies fulfill their obligations to connect and service customers.

LDC is required to charge its customers for the following amounts (all of which, other than distribution charges, represent a pass through of amounts payable to third parties):

- *Distribution Charges* – Distribution charges are designed to recover the costs incurred by LDC in delivering electricity to customers and the OEB-allowed rate of return. Distribution charges are regulated by the OEB and are comprised of a fixed charge and a usage-based (consumption) charge. The volume of electricity consumed by LDC's customers during any period is governed by events largely outside LDC's control (principally, sustained periods of hot or cold weather which increase the consumption of electricity and sustained periods of moderate weather which decrease the consumption of electricity).

- *Electricity Price and Related Regulated Adjustments* – The electricity price and related regulated adjustments represent a pass through of the commodity cost of electricity.

- *Retail Transmission Rate* – The retail transmission rate represents a pass through of wholesale costs incurred by distributors in respect of the transmission of electricity from generating stations to local areas. Retail transmission rates are regulated by the OEB.

- *Wholesale Market Service Charge* – The wholesale market service charge represents a pass through of various wholesale market support costs. Retail rates for the recovery of wholesale market service charges are regulated by the OEB.

LDC is required to satisfy and maintain prudential requirements with the IESO, which include credit support with respect to outstanding market obligations in the form of letters of credit, cash deposits or guarantees from third parties with prescribed credit ratings.

The Corporation is exempt from tax under the *Income Tax Act* (Canada) ("ITA") if not less than 90% of the capital of the Corporation is owned by the City and not more than 10% of the income of the Corporation is derived from activities carried on outside the municipal geographical boundaries of the City. In addition, the Corporation's subsidiaries are also exempt from tax under the ITA provided that all of their capital is owned by the Corporation and not more than 10% of their respective income is from activities carried on outside the municipal geographical boundaries of the City. A corporation exempt from tax under the ITA is also exempt from tax under the *Taxation Act, 2007* (Ontario) ("TA") and the *Corporations Tax Act* (Ontario) ("CTA").

The Corporation and each of its subsidiaries are Municipal Electricity Utilities ("MEUs") for purposes of the Payment In Lieu of Corporate Taxes ("PILs") regime contained in the *Electricity Act, 1998* (Ontario) ("Electricity Act"). The Electricity Act provides that a MEU that is exempt from tax under the ITA, the CTA and the TA is required to make, for each taxation year, a PILs payment to the Ontario Electricity Financial Corporation in an amount equal to the tax that it would be liable to pay under the ITA and the TA (for years ending after 2008) or the CTA (for years ending prior to 2009) if it were not exempt from tax. The PILs regime came into effect on October 1, 2001, at which time the Corporation and each of its subsidiaries were deemed to have commenced a new taxation year for purposes of determining their respective liabilities for PILs payments.

The *Green Energy and Green Economy Act, 2009* (Ontario) (the "Green Energy Act") came into force on May 14, 2009. The Green Energy Act, among other things, permits electricity distribution companies to own renewable energy generation facilities, obligates electricity distribution companies to provide priority connection access for renewable energy generation facilities, empowers the OEB to set CDM targets for electricity distribution companies as a condition of license and requires electricity distribution companies to accommodate the development and implementation of a smart grid in relation to their systems.

Selected Consolidated Financial Data

The selected consolidated financial data presented below should be read in conjunction with the Consolidated Financial Statements.

Years ended December 31,
(in thousands of dollars except for per share amounts)

	2011 $	2010 $	Change $	Change %	2009 $
Revenues	2,809,258	2,611,671	197,587	7.6	2,457,923
Costs					
Purchased power and other	2,238,500	2,062,269	176,231	8.5	1,953,657
Operating expenses	243,547	223,326	20,221	9.1	208,834
Depreciation and amortization	151,022	169,408	(18,386)	(10.9)	162,970
	2,633,069	2,455,003	178,066	7.3	2,325,461
Income before the following:	176,189	156,668	19,521	12.5	132,462
Net financing charges	(75,324)	(71,150)	(4,174)	(5.9)	(70,551)
Gain on disposals of property, plant and equipment ("PP&E")	3,885	3,767	118	3.1	1,013
Change in fair value of investments	-	2,420	(2,420)	(100.0)	(1,049)
Income before provision for PILs	104,750	91,705	13,045	14.2	61,875
Provision for PILs	8,818	25,580	(16,762)	(65.5)	19,742
Net income	95,932	66,125	29,807	45.1	42,133
Basic and fully diluted net income per share	95,932	66,125	29,807	45.1	42,133

As at December 31,
(in thousands of dollars)

	2011 $	2010 $
Consolidated Balance Sheet Data		
Total assets	3,455,777	3,338,614
Current liabilities	448,061	639,751
Long-term liabilities	1,905,468	1,659,484
Total liabilities	2,353,529	2,299,235
Shareholder's equity	1,102,248	1,039,379
Total liabilities and shareholder's equity	3,455,777	3,338,614

Results of Operations – 2011 compared to 2010

Net Income

Net income was $95.9 million in 2011 compared to $66.1 million in 2010. The increase in net income was primarily due to higher net revenues ($21.4 million), lower depreciation expense ($18.4 million) and lower provision for PILs ($16.8 million). These favourable variances were partially offset by higher operating expenses ($20.2 million), higher net financing charges ($4.2 million) and a gain recognized in 2010 in relation with the disposition of the Corporation's long-term investments ($2.4 million).

Net Revenues

Net revenues were $570.8 million in 2011 compared to $549.4 million in 2010 (see "Non-GAAP Financial Measures" below). The increase in net revenues was primarily due to higher regulated distribution revenue at LDC ($26.1 million) partially offset by lower other income ($4.7 million). The increase in distribution revenue was primarily due to the approval by the OEB of a higher revenue requirement balance ($23.6 million) for 2011 to fund LDC's infrastructure modernization program, workforce renewal initiative and incremental maintenance costs (see "Corporate Developments – Distribution Rates for LDC" below). The decrease in other income was primarily due to lower margins in connection with Ontario Power Authority ("OPA") programs and lower late payment charges billed to customers in 2011.

Expenses

Operating expenses were $243.5 million in 2011 compared to $223.3 million in 2010. The increase in operating expenses was primarily due to higher operating labour costs resulting from changes in accounting estimates related to burden rates (see "Changes in Accounting Estimates – Property, Plant and Equipment" below) and higher overall compensation costs due to annual general increase in wages and related benefits ($29.6 million), and higher accounting conversion costs following the decision by the OEB to disallow the recovery of a portion of the costs incurred by the Corporation for its initially planned conversion to International Financial Reporting Standards ("IFRS") as it appeared that such costs were included in prior period electricity distribution rates ($3.0 million). These variances were partially offset by the recognition in 2010 of costs relating to the expected settlement of a class action against LDC ($6.0 million) (see "Legal Proceedings – Christian Helm Class Action" below), the recognition in 2010 of a special charge related to the disallowance by the OEB of a portion of the costs related to the contact voltage remediation activities ($3.8 million) (see "Corporate Developments – Contact Voltage" below) and lower Ontario capital tax expense in 2011 following the elimination of such tax in the second quarter of 2010 ($2.2 million).

Depreciation and amortization expense was $151.0 million in 2011 compared to $169.4 million in 2010. The decrease in depreciation and amortization expense was primarily due to changes in accounting estimates related to useful lives of certain items of PP&E (see "Changes in Accounting Estimates – Property, Plant and Equipment" below). This decrease was partially offset by an increase in depreciation related to the renewal of the regulated electricity distribution infrastructure of LDC. Over the past few years, LDC significantly increased its capital expenditures following the approval by the OEB of higher capital programs aimed at modernizing the electricity infrastructure of LDC (see "Liquidity and Capital Resources – Net Cash Used in Investing Activities" below).

Net Financing Charges

Net financing charges were $75.3 million in 2011 compared to $71.2 million in 2010. The increase in net financing charges was primarily due to higher long-term financing charges from the issuance of senior unsecured debentures in 2011 (see "Corporate Developments – Medium-Term Note Program" below).

Gain on Disposals of PP&E

Gain on disposals of PP&E was $3.9 million in 2011 compared to $3.8 million in 2010. The increase in gain on disposals of PP&E was primarily due to the recognition of gains realized in connection with the disposals of surplus properties at LDC. During 2011, LDC recognized $3.9 million in gain on disposals of surplus properties, of which $1.4 million relates to surplus properties for which the OEB reduced electricity distribution rates in 2010. LDC began recognizing the actual gain realized on the sale of these properties over a one-year period from May 1, 2010 to mirror the actual timing of the reduction in 2010 electricity distribution rates.

Change in Fair Value of Investments

On October 8, 2010, the Corporation sold all of its long-term investments for cash consideration of $50.4 million. In connection with these investments, the Corporation recognized a gain of $2.4 million in the consolidated statement of income for the year ended December 31, 2010.

Provision for PILs

Provision for PILs was $8.8 million in 2011 compared to $25.6 million in 2010. The decrease in the provision for PILs was primarily due to higher deductions for permanent and temporary differences between accounting and tax treatments mainly related to depreciation and capital cost allowance ($18.5 million) and recoveries resulting from favourable resolution of Ministry of Finance PILs audits of LDC for the 2005 and 2006 taxation years ($2.0 million). The decrease in the provision for PILs was partially offset by the effect of higher income in 2011 ($3.7 million).

Results of Operations – 2010 compared to 2009

Net income was $66.1 million in 2010 compared to $42.1 million in 2009. The increase in net income was primarily due to higher net revenues ($45.1 million), a favourable variance in the fair value of investments ($3.5 million) and a higher gain on disposals of surplus PP&E ($2.8 million). These favourable variances were partially offset by higher operating expenses ($14.5 million), higher depreciation expense ($6.4 million) and higher provision for PILs ($5.8 million). For further details, see the Corporation's 2010 MD&A as filed on the System for Electronic Document Analysis and Retrieval ("SEDAR") website at www.sedar.com.

Summary of Quarterly Results

The tables below present unaudited quarterly consolidated financial information of the Corporation for 2011 and 2010.

2011 Quarter Ended, (in thousands of dollars)				
	December 31 $	September 30 $	June 30 $	March 31 $
Revenues	689,624	734,505	683,787	701,342
Costs	648,713	683,433	643,303	657,620
Net income	17,228	28,982	24,270	25,452

2010 Quarter Ended, (in thousands of dollars)				
	December 31 $	September 30 $	June 30 $	March 31 $
Revenues	656,649	680,504	627,707	646,811
Costs	621,179	631,807	588,828	613,189
Net income	10,048	27,687	15,839	12,551

The Corporation's quarterly results are impacted by changes in revenues resulting from variations in seasonal weather conditions, the fluctuations in electricity prices, and the timing and recognition of regulatory decisions. The Corporation's revenues tend to be higher in the first and third quarters of a year as a result of higher energy consumption for winter heating in the first quarter and air conditioning and cooling in the third quarter.

Financial Position

The following table outlines the significant changes in the consolidated balance sheets between 2011 and 2010.

Consolidated Balance Sheet Data As at December 31, 2011 compared to December 31, 2010 (in thousands of dollars)		
Balance Sheet Account	**Increase (Decrease) $**	**Explanation of Significant Change**
Cash and cash equivalents	(175,895)	See "Liquidity and Capital Resources" below.
Investments	34,002	The increase in investments is due to the investment in two floating rate notes in the amounts of $25.0 million and $9.0 million, the first maturing on October 22, 2012 and the second maturing on February 17, 2012, which are guaranteed by a Canadian Schedule I bank.
Accounts receivable, net of allowance for doubtful accounts	14,284	The increase in accounts receivable is primarily due to the timing of the Ontario Clean Energy Benefit Rebate from the IESO, which did not exist in 2010 and the timing of billing and collection activities from large customers.
Unbilled revenue	(25,835)	The decrease in unbilled revenue is primarily due to lower consumption in December 2011 compared to December 2010 and lower energy prices compared to the previous year.
PP&E and intangible assets, net	297,706	The increase in PP&E and intangible assets is primarily due to capital expenditures ($437.1 million) offset by depreciation during the year ($151.0 million).
Regulatory assets	(7,791)	The decrease in regulatory assets is primarily due to the on-going recoveries of charges from customers, partially offset by increases in the retail settlement balances regulated by the OEB.
Future income tax assets	(23,533)	The decrease in future income tax assets is primarily due to a decrease in the net deductible temporary differences between tax and accounting values of PP&E.
Accounts payable and accrued liabilities	38,869	The increase in accounts payable and accrued liabilities is mainly due to timing differences in the settlement of trade payables and consumption and price variances related to electricity payable to the IESO.

Consolidated Balance Sheet Data As at December 31, 2011 compared to December 31, 2010 (in thousands of dollars)		
Balance Sheet Account	**Increase (Decrease) $**	**Explanation of Significant Change**
Deferred revenue	11,941	The increase in deferred revenue is primarily due to a significant balance received in advance from the OPA relating to CDM programs for 2011.
Debentures	53,677	The increase in debentures is primarily due to the issuance of $300.0 million senior unsecured debentures (see "Corporate Developments – Medium-Term Note Program" below), which is partially offset by the repayment of the Corporation's outstanding $245.1 million senior unsecured debentures which matured on December 30, 2011.
Post-employment benefits	9,644	The increase in post-employment benefits is primarily due to higher defined benefit costs.
Regulatory liabilities	(63,426)	The decrease in regulatory liabilities is primarily due to the net disposition of retail settlement balances to customers approved by the OEB and a reduction of future income tax assets payable to customers.
Other liabilities	10,667	The increase in other liabilities is primarily due to a capital lease obligation for contact voltage equipment.
Customers' advance deposits	(9,532)	The decrease in customers' advance deposits is primarily due to the reimbursement of customer deposits during the period in compliance with OEB rules and regulations.
Retained earnings	62,869	The increase in retained earnings is due to net income ($95.9 million) offset by dividends paid ($33.1 million).

Liquidity and Capital Resources

Sources of Liquidity and Capital Resources

The Corporation's primary sources of liquidity and capital resources are cash provided by operating activities, bank financing, interest income and borrowings from debt capital markets. The Corporation's liquidity and capital resource requirements are mainly for capital expenditures to maintain and improve the electricity distribution system of LDC, purchased power expense, net financing charges and prudential requirements.

The Corporation does not believe that equity contributions from the City, its sole shareholder, will constitute a source of capital.

Liquidity and Capital Resources
Year Ended December 31,
(in thousands of dollars)

	2011 $	2010 $
Cash and cash equivalents, beginning of year	330,151	211,370
Net cash provided by operating activities	310,348	280,318
Net cash used in investing activities	(497,859)	(347,584)
Net cash provided by financing activities	11,616	186,047
Cash and cash equivalents, end of year	154,256	330,151

Net Cash Provided by Operating Activities

Net cash provided by operating activities was $310.3 million in 2011 compared to $280.3 million in 2010. The increase in net cash provided by operating activities was primarily due to higher net income ($29.8 million), a variance in the aggregate amount of accounts receivable and unbilled revenue due to the timing of billing and collection activities ($22.0 million) and an increase in deferred revenue relating to a significant balance received in advance from the OPA for CDM programs in 2011 ($13.7 million). These variances were partially offset by a decrease in depreciation and amortization ($18.4 million), a variance in PILs receivable ($13.8 million) and a decrease in net change in other assets and liabilities ($6.4 million).

Net Cash Used in Investing Activities

Net cash used in investing activities was $497.9 million in 2011 compared to $347.6 million in 2010. The increase in net cash used in investing activities was primarily due to the net proceeds received in 2010 in connection with the sale of long-term investments ($50.4 million), the net impact of investing excess cash in low-risk floating rate notes ($34.0 million), higher capital expenditures in 2011 ($46.3 million), a higher change in net regulatory assets and liabilities ($15.7 million) primarily related to a higher variance in 2011 of retail settlement balances regulated by the OEB and the impact of the net proceeds received in 2011 on the disposition of surplus properties ($3.9 million).

The increase in regulated capital expenditures at LDC for the year ended December 31, 2011 amounted to $46.3 million. This increase was primarily due to transformer stations ($25.2 million), metering ($10.6 million), customer connections ($9.5 million), and feeders ($2.3 million). These increases were partially offset by a decrease in distribution lines ($4.4 million).

The following table summarizes the Corporation's capital expenditures for the years indicated.

Capital Expenditures Year Ended December 31, (in thousands of dollars)	2011 $	2010 $
LDC		
Distribution system	361,851	311,781
Technology assets	33,193	39,556
Other (1)	36,139	33,575
	431,183	384,912
Other (2)	5,884	5,872
Total Capital Expenditures	437,067	390,784

Notes:

(1) Consists of leasehold improvements, vehicles, other work-related equipment, furniture and office equipment.
(2) Includes unregulated capital expenditures primarily related to TH Energy.

The increase in capital expenditures was primarily related to higher investment in electricity distribution assets in connection with LDC's infrastructure renewal program approved by the OEB. For 2011, the OEB approved $378.8 million in regulated capital expenditures for LDC in comparison to $350.0 million for 2010. It should be noted that when considering the changes in accounting estimates implemented prospectively by the Corporation in 2011 (see "Changes in Accounting Estimates – Property, Plant and Equipment" below), the OEB effectively approved an increase of $51.0 million in LDC's regulated capital programs for 2011.

The three most significant capital expenditures incurred by LDC in the current year were related to reinforcing and maintaining the electricity distribution system, primarily by replacing aging assets in order to maintain long-term reliability ($256.6 million in 2011 compared to $246.5 million in 2010), upgrading and investing in new stations to improve supply reliability in the downtown area and to provide capacity for load growth within this area ($32.5 million in 2011 compared to $7.0 million in 2010), and net expenditures related to customer connections primarily due to growth in the condominium market, particularly in the downtown core of the City ($28.4 million in 2011 compared to $18.9 million in 2010).

Net Cash Provided by Financing Activities

Net cash provided by financing activities was $11.6 million in 2011 compared to $186.0 million in 2010. The decrease in net cash provided by financing activities was primarily due to the issuance of $200.0 million of senior unsecured debentures to finance the renewal of LDC's electricity infrastructure in 2010, higher reimbursement of customer deposits in 2011 in compliance with OEB rules and regulations ($20.8 million), and a higher dividend paid with respect to net income for the year ended December 31, 2010, which was paid to the City on March 18, 2011 ($8.1 million). The decrease in net cash provided by financing activities was partially offset by the net effect of the net proceeds received in connection with the issuance of $300.0 million of senior unsecured debentures in 2011 and the repayment of $245.1 million of senior unsecured debentures ($54.9 million).

Summary of Contractual Obligations

The following table presents a summary of the Corporation's debentures, major contractual obligations and other commitments.

Summary of Contractual Obligations and Other Commitments
As at December 31, 2011
(in thousands of dollars)

	Total $	2012 $	2013/2014 $	2015/2016 $	After 2016 $
Debentures – principal repayment...	1,470,057	–	470,057	–	1,000,000
Debentures – interest payments.......	631,758	74,905	105,960	91,600	359,293
Operating lease obligations and future commitments........................	76,199	27,715	30,934	12,795	4,755
Capital lease obligations …..............	15,277	2,454	4,849	4,594	3,380
Asset retirement obligations...........	5,811	1,320	511	238	3,742
Total contractual obligations and other commitments….....................	2,199,102	106,394	612,311	109,227	1,371,170

Revolving Credit Facility

The Corporation is a party to a revolving credit facility pursuant to which the Corporation may borrow up to $400.0 million, of which up to $140.0 million is available in the form of letters of credit. Additionally, the Corporation is a party to a bilateral facility for $50.0 million for the purpose of issuing letters of credit mainly to support LDC's prudential requirements with the IESO.

On May 3, 2011, the Corporation extended its revolving credit facility for an additional term, expiring on May 3, 2013. The extension maintained the level of credit available at $400.0 million.

As at December 31, 2011, no amounts had been drawn under the Corporation's revolving credit facility and $45.1 million had been drawn on the bilateral facility.

Prudential Requirements and Third Party Credit Support

The City has authorized the Corporation to provide financial assistance to its subsidiaries, and LDC to provide financial assistance to other subsidiaries of the Corporation, in the form of letters of credit and guarantees, for the purpose of enabling them to carry on their businesses up to an aggregate amount of $500.0 million.

Dividends

The shareholder direction adopted by the City with respect to the Corporation provides that the board of directors of the Corporation will use its best efforts to ensure that the Corporation meets certain financial performance standards, including those relating to the credit rating and dividends. Subject to applicable law, the shareholder direction provides that the Corporation will pay dividends to the City each year amounting to the greater of $25.0 million or 50% of the Corporation's consolidated net income for the year. The dividends are not cumulative and are payable as follows:

- $6.0 million on the last day of each of the first three fiscal quarters during the year;
- $7.0 million on the last day of the fiscal year; and
- the amount, if any, by which 50% of the Corporation's annual consolidated net income for the year exceeds $25.0 million, within ten days after the board of directors of the Corporation approved the Corporation's audited Consolidated Financial Statements for the year.

The board of directors of the Corporation declared and paid dividends totalling $33.1 million in 2011 and $25.0 million in 2010 to the City.

On March 2, 2012, the board of directors of the Corporation declared dividends in the amount of $29.0 million. The dividends are comprised of $23.0 million with respect to net income for the year ended December 31, 2011, payable to the City on March 12, 2012, and $6.0 million with respect to the first quarter of 2012, payable to the City on March 30, 2012.

Credit Rating

The Corporation and the debentures issued under its medium-term note program were rated as follows:

Credit Ratings As at December 31,	**2011**
DBRS Limited	A (high)
Standard & Poor's ("S&P")	A

Corporate Developments

Distribution Rates for LDC

Regulatory developments in Ontario's electricity industry, including current and possible future consultations between the OEB and interested stakeholders, may affect LDC's electricity distribution rates and other permitted recoveries in the future.

LDC's electricity distribution rates are typically effective from May 1 to April 30 of the following year. Accordingly, LDC's distribution revenue for the first four months of 2011 was based on the electricity distribution rates approved for the May 1, 2010 to April 30, 2011 rate year (the "2010 Rate Year"), and the distribution revenue for the remainder of 2011 and for the first four months of 2012 are and will be based on electricity distribution rates approved for the May 1, 2011 to April 30, 2012 rate year (the "2011 Rate Year").

LDC's electricity distribution rates for the 2010 Rate Year and the 2011 Rate Year were determined through an application under the cost of service framework. The cost of service framework sets electricity distribution rates using a detailed examination of evidence and an assessment of the costs incurred by an electricity distributor to provide its service to its customers.

On April 9, 2010, the OEB issued its decision regarding LDC's electricity distribution rates for the 2010 Rate Year. The decision provided for a distribution revenue requirement and rate base of $518.7 million and $2,140.7 million, respectively. In addition, the decision provided for capital program spending levels and operating, maintenance and administration spending levels of $350.0 million and $204.1 million, respectively.

On July 7, 2011, the OEB issued its decision regarding LDC's electricity distribution rates for the 2011 Rate Year. The decision provided for a distribution revenue requirement and rate base of $522.0 million and $2,298.2 million, respectively. In addition, the decision provided for capital program spending levels and operating, maintenance and administration spending levels of $378.8 million and $238.0 million, respectively.

On August 26, 2011, LDC filed a rate application, following the cost of service framework, with the OEB seeking approval of separate and successive revenue requirements and corresponding electricity distribution rates for three rate years commencing on May 1, 2012, May 1, 2013 and May 1, 2014 (the "2012-2014 Rate Application"). The requested distribution revenue requirements for these rate years were $571.4 million, $639.5 million, and $712.8 million, respectively, and the expected rate bases for these rate years were $2,636.3 million, $3,053.5 million, and $3,503.2 million, respectively.

Pursuant to the incentive regulation mechanism framework, the OEB established, as a preliminary issue in the 2012-2014 Rate Application, that it would consider the question of whether the application filed by LDC was acceptable or whether it should be dismissed. In particular, the OEB established that in order for it to find that LDC's 2012-2014 Rate Application was acceptable, LDC would be required to show why and how LDC cannot adequately manage its resources and financial needs under the incentive regulation mechanism framework. The incentive regulation mechanism framework provides for an annual adjustment to an electricity distributor's rates based on a formulaic calculation with no direct examination of evidence regarding the electricity distributor's actual costs and infrastructure needs.

LDC filed evidence supporting its position for electricity distribution rates to be set under the cost of service framework as part of its 2012-2014 Rate Application. In particular, LDC provided evidence that it cannot adequately manage its resources and financial needs under the incentive regulation mechanism framework. The OEB established a process by which a portion of LDC's evidence was tested during an oral hearing held in November 2011.

On January 5, 2012, the OEB rendered its decision on the preliminary issue and dismissed LDC's cost of service 2012-2014 Rate Application. In its decision, the OEB found that LDC was not permitted to deviate from the standard incentive regulation mechanism framework cycle, and LDC will therefore be required to file its request for electricity distribution rates commencing on May 1, 2012 pursuant to the formulaic adjustment and the incremental capital module provided for under the incentive regulation mechanism framework.

On January 25, 2012, LDC filed with the OEB a motion to review the OEB's January 5, 2012 decision.

On February 6, 2012, LDC filed a notice of appeal with the Ontario Divisional Court regarding the OEB's January 5, 2012 decision.

Pursuant to the OEB's decision of January 5, 2012, LDC is currently preparing an application for electricity distribution rates using the incentive regulation mechanism framework, including the filing of an incremental capital module. The quantum of this application is consistent with the capital program spending levels previously approved by the OEB for the 2011 Rate Year.

Under the incentive regulation mechanism framework, LDC has to significantly reduce its costs structure, and in particular its operating expenses, in order to meet its financial obligations. Accordingly, in the first quarter of 2012, LDC began implementing a restructuring program aimed at reducing its operating costs in the future. The main component of this restructuring program is a workforce reduction plan targeting both union and management employees. As at March 2, 2012, the costs incurred as a result of the restructuring program amounted to approximately $19.3 million, which were mainly related to employee severance and buy-out costs.

The Corporation continues to assess all of the impacts related to the imposition by the OEB of the incentive regulation mechanism framework, which impacts may include additional restructuring costs. The incremental restructuring costs could have a material impact on the Corporation's consolidated financial statements in the future.

Street Lighting Activities

On June 15, 2009, the Corporation filed an application with the OEB seeking an electricity distribution licence for a new wholly-owned legal entity to which the Corporation intended to transfer the street lighting assets of TH Energy. Concurrently, the Corporation filed another application with the OEB seeking approval for the merger of LDC and the new legal entity. The main objective of these applications was to transfer the street lighting assets to the regulated electricity distribution activities of LDC to increase the overall safety of the related infrastructure.

On February 11, 2010, the OEB issued its decision in regard to these applications. In its decision, the OEB agreed that, under certain conditions, the treatment of certain types of street lighting assets as regulated assets is justified. The OEB ordered the Corporation to provide a detailed valuation of the street lighting assets and to perform an operational review to determine which street lighting assets could become regulated assets. The Corporation performed a detailed asset operational review and financial valuation of the street lighting assets, which was submitted to the OEB on January 31, 2011.

On August 3, 2011, the OEB issued its final decision allowing the transfer of a portion of the street lighting assets to the new wholly-owned legal entity, and for LDC to amalgamate with the new legal entity.

On January 1, 2012, the Corporation completed the transfer of street lighting assets to LDC for a purchase price of $28.5 million, subject to post closing adjustment and transaction costs.

Medium-Term Note Program

On November 18, 2011, the Corporation issued $300.0 million in 10-year senior unsecured debentures ("Series 7") which bear interest at the rate of 3.54% per annum and are payable semi-annually in arrears in equal instalments on May 18 and November 18 of each year. The Series 7 debentures mature on November 18, 2021 and contain covenants which, subject to certain exceptions, restrict the ability of the Corporation and LDC to create security interests, incur additional indebtedness or dispose of all or substantially all of their assets. The net proceeds from this issuance were used to repay the $245.1 million senior unsecured debentures of the Corporation which matured on December 30, 2011 and the balance is expected to be used for general corporate purposes.

CDM Activities

On March 31, 2010, the Minister of Energy and Infrastructure of Ontario, under the guidance of sections 27.1 and 27.2 of the OEB Act, directed the OEB to establish CDM targets to be met by electricity distributors. Accordingly, on November 12, 2010, the OEB amended LDC's distribution licence to require LDC, as a condition of its licence, to achieve 1,304 Gigawatt-Hours of energy savings and 286 Megawatts of summer peak demand savings, over the period beginning January 1, 2011 through December 31, 2014.

Effective January 1, 2011, LDC entered into an agreement with the OPA to deliver CDM programs in the amount of approximately $50.0 million extending from January 1, 2011 to December 31, 2014 (the "Master CDM Program Agreement"). As at December 31, 2011, LDC received approximately $19.9 million from the OPA for the delivery of CDM programs under the Master CDM Program Agreement. All programs to be delivered under the Master CDM Program Agreement are fully funded and paid in advance by the OPA. These programs are expected to support the achievement of the mandatory CDM targets described above.

On January 10, 2011, LDC filed an application with the OEB seeking an order granting approval of funding for CDM programs specific to its customer base. LDC requested funding for eight specific CDM programs amounting to $50.7 million. On July 12, 2011, the OEB issued its decision regarding the CDM programs of LDC. In its decision, the OEB approved with modifications two of the eight programs for a total funding of $5.3 million. The modifications directed by the OEB included changes to the term and nature of those two programs. The OEB did not approve the other six programs as it considered them to be duplicative of existing CDM programs already funded by the OPA.

On August 3, 2011, LDC filed a letter with the OEB informing them that, due to the modified terms and nature of the two approved programs, LDC's revised economic assessment showed these two programs to be uneconomic, and that they would not be implemented. Accordingly, LDC expects to continue to work with the OPA to expand the roster of current CDM programs in order to achieve its mandated CDM targets.

Special Purpose Charge

On April 9, 2010, the OEB informed electricity distributors of a Special Purpose Charge ("SPC") assessment under Section 26.1 of the OEB Act, for the Ministry of Energy and Infrastructure conservation and renewable energy program costs. The OEB assessed LDC the amount of $9.7 million for its apportioned share of the total provincial amount of the SPC of $53.7 million in accordance with the rules set out in Ontario Regulation 66/10 (the "SPC Regulation"). In accordance with Section 9 of the SPC Regulation, LDC was allowed to recover this balance. The recovery was completed as at April 30, 2011.

Contact Voltage

On December 10, 2009, the OEB issued an initial decision in regard to the costs incurred in 2009 for the remediation of safety issues related to contact voltage relating to LDC's electricity distribution infrastructure. The decision provided for the recovery of allowable actual expenditures incurred above the amount deemed as controllable expenses in LDC's 2009 approved electricity distribution rates. At the time of the decision, the Corporation estimated the allowable recovery of costs at $9.1 million.

On October 29, 2010, the OEB issued a second decision in the matter, following further review of costs incurred by LDC. In this decision, the OEB deemed the balance allowable for recovery at $5.3 million. The variance from the Corporation's original estimate is mainly due to the OEB's interpretation of the definition of controllable expenses used to determine the final allowable recovery. In connection with this decision from the OEB, the Corporation revised its recovery estimate for contact voltage costs, resulting in an increase in operating expenses of $3.8 million in 2010. On November 18, 2010, LDC filed a motion to review the decision with the OEB seeking an amendment to allow for recovery in accordance with the initial decision rendered on December 10, 2009. On March 25, 2011, the OEB issued its decision on the LDC motion, denying the requested additional recovery.

OEB PILs Proceeding

The OEB conducted a review of the PILs variances accumulated in regulatory variance accounts for the period from October 1, 2001 to April 30, 2006 for certain MEUs. On June 24, 2011, the OEB issued its decision for these MEUs and provided guidelines for the calculation and further disposition of the balances accumulated in the PILs regulatory variance accounts.

LDC has reviewed the balances of its PILs regulatory variance accounts and applied the guidelines provided by the OEB. As at December 31, 2011, LDC estimated its liability at approximately $2.8 million. This balance has been recorded in the Corporation's Consolidated Financial Statements. LDC intends to apply for disposition of this balance in 2012. The amount to be approved by the OEB will be based on the OEB's interpretation and application of its guidelines and the final balance which is yet to be approved by the OEB could differ materially from LDC's estimation of its liability.

Payments in Lieu of Additional Municipal and School Taxes

The Ministry of Finance has issued assessments in respect of payments in lieu of additional municipal and school taxes under section 92 of the Electricity Act that are in excess of the amounts LDC believes are payable. The dispute arose as a result of inaccurate information incorporated into Ontario Regulation 224/00. The Corporation has worked with the Ministry of Finance to resolve this issue, and as a result the Ministry of Finance issued Ontario Regulation 423/11 on August 31, 2011. The new regulation revoked Ontario Regulation 224/00 and corrected inaccurate information retroactively to 1999.

The balance assessed by the Ministry of Finance on its most recent statement of account amounts to approximately $10.0 million above the balance accrued by the Corporation. While the Corporation expects that reassessments will be issued as a consequence of the change in regulation, there can be no assurance that the Corporation will not have to pay the full assessed balance in the future.

Customer Care and Billing System

On July 6, 2011, LDC implemented a new customer care and billing system for its regulated electricity distribution business. The new system allows for more flexibility for its users and provides better information for the calculation of accounting estimates related to revenue recognition. The system provides an integrated billing platform leveraging the technology of the smart meters installed over the past few years.

Changes to the Corporation's Board of Directors

On March 31, 2010, the City, as the sole shareholder of the Corporation, appointed David Williams as an independent director of the Corporation. His appointment is effective to November 30, 2012.

On December 7, 2010, the City, as the sole shareholder of the Corporation, appointed three new councillors, Shelley Carroll, Josh Colle, and Ron Moeser as the City's designates on the board of directors of the Corporation to replace Joe Pantalone, Gordon Perks and Bill Saundercook. Their appointments are effective to November 30, 2012.

Effective December 2, 2010, William Rupert resigned as an independent director of the Corporation.

Legal Proceedings

In the ordinary course of business, the Corporation is subject to various litigation and claims with customers, suppliers, former employees and other parties. On an ongoing basis, the Corporation assesses the likelihood of any adverse judgments or outcomes as well as potential ranges of probable costs and losses. A determination of the provision required, if any, for these contingencies is made after analysis of each individual issue. The provision may change in the future due to new developments in each matter or changes in approach, such as a change in settlement strategy.

Christian Helm Class Action

On December 6, 2010, a statement of claim in a proposed class action was issued against LDC. The claim seeks general and special damages in the amount of $100.0 million for disgorgement of unjust gains allegedly resulting from the receipt of interest on overdue accounts at a rate exceeding 5% per annum in contravention of the *Interest Act* (Canada) ("Interest Act"). A statement of defence has been filed. Prior to any certification of the action as a class proceeding, cross summary judgment motions were heard in June 2011 to determine whether the Interest Act has been breached. On February 1, 2012, prior to the release of the decisions on the summary judgment motions, the parties reached a settlement of the matter, which settlement now requires court approval. The Settlement Approval Hearing is scheduled for April 30, 2012. If the settlement receives court approval, damages and costs of approximately $6.0 million shall be paid by LDC. In 2010, the Corporation accrued a liability to cover the expected settlement.

If the settlement does not receive court approval, the decision on the cross summary judgment motions will be released. In this event, if the court finds a breach of the Interest Act, subject to appeals, the proceeding will continue, and LDC will rely on other defences. While LDC believes it has a defence to this claim, there is no guarantee that it will be successful in defending the action and therefore, the outcome of this proceeding could have a material impact on the Corporation's consolidated financial statements and results of operations.

2 Secord Avenue

An action was commenced against LDC in September 2008 in the Ontario Superior Court of Justice under the *Class Proceedings Act, 1992* (Ontario) ("Class Proceedings Act") seeking damages in the amount of $30.0 million as compensation for damages allegedly suffered as a result of a fire and explosion in an underground vault at 2 Secord Avenue on July 20, 2008. This action is at a preliminary stage. The statement of claim has been served on LDC, a statement of defence and third party claim have been served by LDC and a third party defence and counterclaim against LDC seeking damages in the amount of $51.0 million have been filed. A certification order has been issued. Affidavits of documents have been produced by LDC to the other parties and examinations for discovery have commenced and are continuing. Given the preliminary status of this action, it is not possible to reasonably quantify the effect, if any, of this action on the financial performance of the Corporation. If damages were awarded, LDC would make a claim under its liability insurance which the Corporation believes would cover any damages which may become payable by LDC in connection with the action.

On December 20, 2010, LDC was served with a statement of claim by the City seeking damages in the amount of $2.0 million as a result of the fire at 2 Secord Avenue. A statement of defence and third party claim have been served. Given the preliminary status of this action, it is not possible to reasonably quantify the effect, if any, of this action on the financial performance of the Corporation. If damages were awarded, LDC would make a claim under its liability insurance which the Corporation believes would cover any damages which may become payable by LDC in connection with the action.

By order of the court, the above actions and a smaller non-class action commenced in April 2009 involving the same incident will be tried at the same time or consecutively.

2369 Lakeshore Boulevard West

A third party action was commenced against LDC in October 2009 in the Ontario Superior Court of Justice under the Class Proceedings Act seeking damages in the amount of $30.0 million as compensation for damages allegedly suffered as a result of a fire in the electrical room at 2369 Lakeshore Boulevard West on March 19, 2009. Subsequently, in March 2010, the plaintiff in the main action amended its statement of claim to add LDC as a defendant. The plaintiff in the main action seeks damages in the amount of $10.0 million from LDC. Both actions

are at a preliminary stage and the certification hearing is scheduled for September 2012. Statements of defence to the main action and to the third party claim have not been filed. Accordingly, given the preliminary status of these actions, it is not possible at this time to reasonably quantify the effect, if any, of these actions on the financial performance of the Corporation. If damages were awarded, LDC would make a claim under its liability insurance which the Corporation believes would cover any damages which may become payable by LDC in connection with these actions.

Another third party action was commenced against LDC in October 2009 in the Ontario Superior Court of Justice seeking damages in the amount of $30.0 million as compensation for damages allegedly suffered as a result of the fire at 2369 Lakeshore Boulevard West. Subsequently, in March 2010, the plaintiff in the main action amended its statement of claim to add LDC as a defendant. The plaintiff in the main action seeks damages in the amount of $0.4 million from LDC. LDC has filed a statement of defence, crossclaim and counterclaim. Examinations for discovery have not taken place but are to be completed by February 29, 2012 pursuant to a court ordered timetable. Accordingly, given the preliminary status of these actions, it is not possible at this time to reasonably quantify the effect, if any, of these actions on the financial performance of the Corporation. If damages were awarded, LDC would make a claim under its liability insurance which the Corporation believes would cover any damages which may become payable by LDC in connection with these actions.

On August 29, 2011, LDC was served with a statement of claim by the owner of the building and the property management company for the building seeking damages in the amount of $2.0 million as a result of the fire at 2369 Lakeshore Boulevard West. LDC has filed a statement of defence and counterclaim. Given the preliminary status of this action, it is not possible to reasonably quantify the effect, if any, of this action on the financial performance of the Corporation. If damages were awarded, LDC would make a claim under its liability insurance which the Corporation believes would cover any damages which may become payable by LDC in connection with the action.

Adamopoulos

An action was commenced against LDC in November 2004 in the Ontario Superior Court of Justice seeking damages in the amount of $7.8 million as compensation for damages allegedly suffered as a result of a motor vehicle accident involving an LDC vehicle on January 9, 2001. The plaintiff's motion increasing its claim for damages to $23.8 million was granted on July 7, 2010. This matter has been settled and a court order has been issued dismissing the action and all related claims by payment of a total amount of approximately $4.6 million. LDC's liability insurance covered the settlement amount.

Share Capital

The authorized share capital of the Corporation consists of an unlimited number of common shares of which 1,000 common shares are issued and outstanding as at the date hereof.

Transactions with Related Parties

The City is the sole shareholder of the Corporation. Subsidiaries of the Corporation provide certain services to the City at commercial and regulated rates, including electricity, street lighting and energy management services. All transactions with the City are conducted at prevailing market prices and normal trade terms. Additional information with respect to related party transactions between the Corporation and its subsidiaries, as applicable, and the City is set out below.

Transactions with Related Parties Summary
Year Ended December 31,
(in thousands of dollars)

	2011 $	2010 $
Revenues	147,469	147,399
Operating expenses and capital expenditures	30,582	14,068
Net financing charges	-	7,487
Dividends	33,063	25,000

Transactions with Related Parties Summary As at December 31, (in thousands of dollars)	2011 $	2010 $
Accounts receivable, net of allowance for doubtful accounts	8,412	6,711
Unbilled revenue	8,692	9,830
Other assets	7,279	7,368
Accounts payable and accrued liabilities	25,085	12,164
Customers' advance deposits	8,714	10,953

Revenues represent amounts charged to the City primarily for electricity and street lighting services. Operating expenses and capital expenditures represent amounts charged by the City for purchased road cut repairs, property taxes and other services. Net financing charges represent interest paid to the City on the promissory note which was monetized on April 1, 2010. Dividends represent dividends paid to the City.

Accounts receivable, net of allowance for doubtful accounts represent receivables from the City primarily for relocation services, sale of electricity and street lighting services. Unbilled revenue represents receivables from the City related to the provision of electricity not yet billed. Other assets represent amounts for prepaid land leases from the City. Accounts payable and accrued liabilities represent amounts payable to the City relating to road cut repairs and other services, as well as funds received from the City for the construction of electricity distribution assets. Customers' advance deposits represent funds received from the City for future expansion projects.

See note 20 to the Consolidated Financial Statements.

Risk Factors

The financial performance of the Corporation is subject to a variety of risks including those described below:

Condition of Distribution Assets

LDC estimates that approximately one-third of its electricity distribution assets are past their expected useful life. LDC's ability to continue to provide a safe work environment for its employees and a reliable and safe distribution service to its customers and the general public will depend on, among other things, the OEB allowing recovery of costs in respect of LDC's maintenance program and capital expenditure requirements for distribution plant refurbishment and replacement.

Regulatory Developments

Ontario's electricity industry regulatory developments and policy changes may affect the electricity distribution rates charged by LDC and the costs LDC is permitted to recover. This may in turn have a material adverse effect on the financial performance of the Corporation and or in its ability to provide reliable service to its customers. In particular, there can be no assurance that:

- the OEB will approve LDC's electricity distribution rates under the incentive regulation mechanism framework, including the incremental capital module, at levels that will permit LDC to carry out its planned capital work programs required to maintain reliable service to its customers and earn the allowed rate of return on the investment in the business;
- the OEB will not set a lower recovery for LDC's cost of capital;
- the full cost of providing service to distribution customers will be permitted to be recovered through LDC's electricity distribution rates;

- the OEB will not permit competitors to provide distribution services in LDC's licensed area, or permit loads within LDC's service area to become electrically served by a means other than through LDC's electricity distribution system;
- the OEB will allow recovery for revenue lost as a consequence of unanticipated effects of CDM;
- parts of LDC's services will not be separated from LDC and opened to competition; or
- regulatory or other changes will not be made to the PILs regime.

Changes to any of the laws, rules, regulations and policies applicable to the businesses carried on by the Corporation could also have a significant impact on the Corporation. There can be no assurance that the Corporation will be able to comply with applicable future laws, rules, regulations and policies. Failure by the Corporation to comply with applicable laws, rules, regulations and policies may subject the Corporation to civil or regulatory proceedings that may have a material adverse effect on the Corporation.

Information Technology Infrastructure

LDC's ability to operate effectively is in part dependent on the development, maintenance and management of complex information technology systems. Computer systems are employed to operate LDC's electricity distribution system, financial and billing systems and business systems to capture data and to produce timely and accurate information. Failures of LDC's financial, business and operating systems could have a material adverse effect on the Corporation's business, operating results, financial condition and prospects.

LDC's electricity distribution infrastructure and technology systems are also potentially vulnerable to damage or interruption from cyber attacks, which could have an adverse impact on its operations, financial conditions, brand and reputation. While LDC has implemented protective measures to monitor the risk of a cyber attack and mitigate its effects, there can be no assurance that such protective measures will be completely effective in protecting LDC's electricity distribution infrastructure or assets from a cyber attack or the effects thereof.

Labour Relations

The Corporation's ability to operate successfully in the electricity industry in Ontario will continue to depend in part on its ability to make changes to existing work processes and conditions to adapt to changing circumstances. The Corporation's ability to make such changes, in turn, will continue to depend in part on its relationship with its labour unions and its ability to develop plans and approaches that are acceptable to its labour unions. There can be no assurance that the Corporation will be able to secure the support of its labour unions.

Natural and Other Unexpected Occurrences

LDC's operations are exposed to the effects of natural and other unexpected occurrences such as severe or unexpected weather conditions, terrorism and pandemics. Although LDC's facilities and operations are constructed, operated and maintained to withstand such occurrences, there can be no assurance that they will successfully do so in all circumstances. Any major damage to LDC's facilities or interruption of LDC's operations arising from these occurrences could result in lost revenues and repair costs that can be substantial. Although the Corporation has insurance, if it sustained a large uninsured loss caused by natural or other unexpected occurrences, LDC would apply to the OEB for the recovery of the loss. There can be no assurance that the OEB would approve, in whole or in part, such an application.

Electricity Consumption

LDC's electricity distribution rates are comprised of a fixed charge and a usage-based (consumption) charge. The volume of electricity consumed by LDC's customers during any period is governed by events largely outside LDC's control (e.g., principally sustained periods of hot or cold weather could increase the consumption of electricity, sustained periods of mild weather could decrease the consumption of electricity, and general economic conditions could affect overall electricity consumption). Accordingly, there can be no assurance that LDC will earn the revenue requirement approved by the OEB.

Economic conditions could also lead to lower overall electricity consumption, particularly in the commercial customer segment, which is estimated to be the most sensitive to economic changes. Lower electricity consumption from commercial customers could negatively impact LDC's revenue. On an annual basis, a decrease of 1% in electricity consumption would reduce net revenue by approximately $3.6 million.

Market and Credit Risk

LDC is subject to credit risk with respect to customer non-payment of electricity bills. LDC is permitted to mitigate the risk of customer non-payment using any means permitted by law, including security deposits (including letters of credit, surety bonds, cash deposits or lock-box arrangements, under terms prescribed by the OEB), late payment penalties, pre-payment, pre-authorized payment, load limiters or disconnection. In the event of an actual payment default and a corresponding bad debt expense incurred by LDC, roughly 80% of the expense would be related to commodity and transmission costs and the remainder to LDC's distribution revenue. While LDC would be liable for the full amount of the default, there can be no assurance that the OEB would allow recovery of the bad debt expense from remaining customers. Established practice in such cases is that the OEB would examine any electricity distributor's application for recovery of extraordinary bad debt expenses on a case-by-case basis.

LDC is also exposed to fluctuations in interest rates as its regulated rate of return is derived using a formulaic approach, which is based in part on a forecast of long-term Government of Canada bond yields and A-rated Canadian utility bond spreads. LDC estimates that a 1% (100 basis point) reduction in long-term Government of Canada bond yields used to determine its regulated rate of return would reduce LDC's net income, as at December 31, 2011, by approximately $4.6 million.

The Corporation is exposed to fluctuations in interest rates for the valuation of its post-employment benefit obligations. The Corporation estimates that a 1% (100 basis point) increase in the discount rate used to value these obligations would decrease the accrued benefit obligation, as at December 31, 2011, by approximately $33.1 million, and a 1% (100 basis point) decrease in the discount rate would increase the accrued benefit obligation, as at December 31, 2011, by approximately $42.9 million.

Additional Debt Financing

Cash generated from operations, after the payment of expected dividends, will not be sufficient to repay existing indebtedness, fund capital expenditures and meet other obligations. The Corporation relies on debt financing through its Medium-Term Note Program or existing credit facilities to repay existing indebtedness and fund capital expenditures. The Corporation's ability to arrange sufficient and cost-effective debt financing could be adversely affected by a number of factors, including financial market conditions, the regulatory environment in Ontario, the Corporation's results of operations and financial condition, the ratings assigned to the Corporation and its debentures by credit rating agencies, the current timing of the Corporation's debentures and general economic conditions.

Work Force Renewal

Over the next decade, a significant portion of LDC's employees will become eligible for retirement, including potential retirements occurring in supervisory, trades and technical positions. Accordingly, LDC will be required to attract, train and retain skilled employees. There can be no assurance that LDC will be able to attract and retain the required workforce.

Insurance

Although the Corporation maintains insurance, there can be no assurance that the Corporation will be able to obtain or maintain adequate insurance in the future at rates it considers reasonable or that insurance will continue to be available. Further, there can be no assurance that available insurance will cover all losses or liabilities that might arise in the conduct of the Corporation's business. The Corporation self-insures against certain risks (e.g., business interruption and physical damage to certain automobiles). The occurrence of a significant uninsured claim or a claim in excess of the insurance coverage limits maintained by the Corporation could have a material adverse effect on the Corporation's results of operations and financial position.

Credit Rating

Should the Corporation's credit rating from both credit rating agencies fall below "A"(minus) (S&P) and "A"(low) (DBRS), the Corporation and its subsidiaries may be required to post additional collateral with the IESO.

Conflicts of Interest

The City owns all of the outstanding shares of the Corporation and has the power to determine the composition of the board of directors of the Corporation and influence the Corporation's major business and corporate decisions, including its financing programs and dividend payments. A conflict may arise between the City's role as the sole shareholder of the Corporation and its role as the administrator of the City's budget and other matters for the residents of the City.

Change of Ownership

The City may also decide to sell all or part of the Corporation. In the case of such event, depending on the nature of the transaction, the Corporation's credit ratings could be negatively affected.

Conversion to US GAAP

The Corporation plans to commence reporting under US GAAP in its first quarterly consolidated financial statements in 2012. The Corporation does not believe that the adoption of US GAAP will have a material impact on its consolidated financial statements. However, given that the decision granted by the Canadian securities regulatory authorities only allows for the option to prepare consolidated financial statements in accordance with US GAAP for fiscal years beginning before January 1, 2015, and the continued uncertainty around the timing, scope and eventual adoption of a rate-regulated accounting ("RRA") standard under IFRS and the potential material impact of RRA on the Corporation's consolidated financial statements, if the Corporation were to adopt the use of IFRS for fiscal years beginning on or after January 1, 2015, it may have an impact on the Corporation's future financial position and results of operations, which cannot be reasonably quantified at this time.

Real Property Rights

Certain terminal stations and municipal sub-stations of LDC are located on lands owned by the Province, the City and others. In some cases, LDC does not have and may not be able to obtain formal access agreements with respect to such facilities. Failure to obtain or maintain access agreements could adversely affect LDC's operations.

LDC Competition

In the past, there had been one electricity distributor in each region of Ontario. Under the current regulatory regime, a person must obtain a licence from the OEB in order to own and operate an electricity distribution system. LDC has the right to distribute electricity in the City. Although the distribution licence specifies the area in which the distributor is authorized to distribute electricity, unless otherwise provided, the licence does not provide exclusive distribution rights for such area.

The Corporation believes that the complexities and potential inefficiencies that would be created by having multiple electricity distributors authorized to serve a single area are likely to result in the continuation of the practice of having a single electricity distributor authorized to serve a single area. In addition, the Corporation believes that there are significant barriers to entry with respect to the business of electricity distribution in Ontario, including the cost of maintaining an electricity distribution system, OEB regulation of electricity distribution rates and the level of regulatory compliance required to operate an electricity distribution system. However, the Corporation recognizes that more than one distribution licence could be issued for the same area and there is a possibility that in the future some business functions or activities could be separated from LDC and made open to competition from non-regulated business entities, or that defined geographical areas within LDC's service area may be electrically supplied by a means other than through LDC's electricity distribution system.

Non-GAAP Financial Measures

The Corporation's MD&A includes "net revenue" which is a non-GAAP financial measure. The definition of net revenues is revenue minus the cost of purchased power and other. This measure does not have any standard meaning prescribed by Canadian GAAP and is not necessarily comparable to similarly titled measures of other companies. The Corporation uses this measure to assess its performance and to further make operating decisions.

Critical Accounting Estimates

The preparation of the Corporation's Consolidated Financial Statements in accordance with Canadian GAAP requires management to make estimates and assumptions which affect the reported amounts of assets, liabilities, revenues and costs, and related disclosures of commitments and contingencies. The estimates are based on historical experience, current conditions and various other assumptions that are believed to be reasonable under the circumstances, the results of which form the basis for making judgments about the carrying values of assets and liabilities as well as identifying and assessing the accounting treatment with respect to commitments and contingencies. Actual results may differ from these estimates and judgments under different assumptions or conditions.

The following critical accounting estimates involve the more significant estimates and judgments used in the preparation of the Consolidated Financial Statements:

Regulatory Assets and Liabilities

Regulatory assets as at December 31, 2011, amounted to $77.3 million and primarily relate to the deferral of smart meters expenditures incurred in 2009 and 2008. Regulatory liabilities as at December 31, 2011, amounted to $210.3 million and primarily relate to future income tax assets payable to customers and retail settlement balances to customers approved by the OEB. These assets and liabilities can be recognized for rate-setting and financial reporting purposes only if the OEB directs the relevant regulatory treatment or if future OEB direction is judged to be probable. In the event that the disposition of these balances was no longer deemed to be probable, the balances would be recorded in the Corporation's consolidated statements of income in the period that the assessment is made.

Environmental Liabilities and Asset Retirement Obligations

The Corporation recognizes a liability for the future removal and handling costs for contamination in distribution equipment in service and in storage and for the future environmental remediation of certain properties. The estimation of such a liability requires that assumptions be made, such as the number of assets and contamination levels of equipment, and the number of contaminated properties and the extent of contamination. All factors used in deriving the Corporation's environmental liabilities and asset retirement obligations ("ARO") represent management's best estimates based on the planned approach of meeting regulatory requirements. However, it is possible that number of contaminated assets, current cost estimates, inflation assumptions and assumed pattern of annual cash flows may differ significantly from the Corporations' assumptions.

ARO amounted to $4.9 million as at December 31, 2011 compared to $5.0 million as at December 31, 2010. The Corporation estimates the undiscounted amount of cash flows required over the next one to 45 years to settle the ARO is $5.8 million for 2011 compared to $6.6 million for 2010. Discount rates ranging from 1.39% to 6.60% were used to calculate the carrying value of the ARO as at December 31, 2011 and as at December 31, 2010. No assets have been legally restricted for settlement of the liability.

Employee Future Benefits

Employee future benefits other than pension provided by the Corporation include medical, dental and life insurance benefits, and accumulated sick leave credits. These plans provide benefits to employees when they are no longer providing active service. The accrued benefit obligations and current service cost are calculated by independent actuaries using the projected benefit method prorated on service and based on assumptions that reflect management's best estimate. The assumptions were determined by management recognizing the recommendations of the Corporation's actuaries. There could be no assurance that actual employee's future benefits cost will not differ significantly from the estimates calculated using management's assumptions.

Revenue Recognition

Revenues from the sale of electricity are recorded on a basis of cyclical billings and also include unbilled revenues accrued in respect of electricity delivered but not yet billed. The unbilled revenue accrual at the end of each period is based on the difference between the forecast revenue and the actual amounts billed. The development of the revenue forecast requires estimates of customer growth, economic activity and weather conditions. There can be no assurance that actual unbilled revenue estimates will not differ materially from actual revenue for the period.

Significant Accounting Policies

The Consolidated Financial Statements of the Corporation have been prepared in accordance with Canadian GAAP including accounting principles prescribed by the OEB in the handbook "Accounting Procedures Handbook for Electric Distribution Utilities" ("AP Handbook") and are presented in Canadian dollars. In preparing the Consolidated Financial Statements, management makes estimates and assumptions which affect the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities at the date of the Consolidated Financial Statements and the reported amounts of revenues and expenses for the year. Actual results could differ from those estimates, including changes as a result of future decisions made by the OEB, the Ministry of Energy, or the Ministry of Finance. The significant accounting policies of the Corporation are summarized in note 3 to the Consolidated Financial Statements.

Changes in Accounting Estimates

Property, Plant and Equipment

Effective January 1, 2011, the Corporation revised its estimates of useful lives of certain items of PP&E following a detailed review and analysis supported by external third-party evidence. These changes in estimates have been accounted for on a prospective basis in the Consolidated Financial Statements effective January 1, 2011.

Effective January 1, 2011, the Corporation revised its estimates of burden rates of certain items of PP&E following a detailed review and analysis of all the components included in such burden rates. These changes in estimates of burden rates include changes in the allocation of engineering and administration costs, changes in the calculation of standard labour rates, and changes in the calculation of materials handling costs. These changes in estimates have been accounted for on a prospective basis in the Consolidated Financial Statements effective January 1, 2011.

The changes discussed above were reflected in the 2011 electricity distribution rates approved by the OEB on July 7, 2011. Accordingly, these changes decreased distribution revenues by approximately $24.6 million, increased operating expenses by approximately $22.0 million, decreased depreciation expenses by approximately $33.0 million and decreased PILs by approximately $13.6 million for the year ended December 31, 2011 and are expected to impact depreciation expenses proportionately in future periods.

See note 3(f) to the Consolidated Financial Statements.

Future Accounting Pronouncements

Adoption of New Accounting Standards

Publicly accountable enterprises in Canada were required to adopt IFRS in place of Canadian GAAP for interim and annual reporting purposes for fiscal years beginning on or after January 1, 2011.

Prior to the developments noted below, the Corporation's IFRS conversion project was proceeding as planned to meet the January 1, 2011 conversion date.

Rate-Regulated Accounting

In accordance with Canadian GAAP, the Corporation currently follows specific accounting policies unique to a rate-regulated business. Under RRA, the timing and recognition of certain expenses and revenues may differ from those otherwise expected under Canadian GAAP in order to appropriately reflect the economic impact of regulatory decisions regarding the Corporation's regulated revenues and expenditures. These timing differences are recorded as regulatory assets and regulatory liabilities on the Corporation's consolidated balance sheets and represent current rights and obligations regarding cash flows expected to be recovered from or refunded to customers, based on decisions and approvals by the OEB. As at December 31, 2011, the Corporation reported $77.3 million of regulatory assets and $210.3 million of regulatory liabilities.

On July 23, 2009, the International Accounting Standards Board ("IASB") issued an Exposure Draft proposing accounting requirements for rate-regulated activities. The IASB received a significant number of comment letters with diverging opinions. On September 3, 2010, in preparation for the September IASB meetings, the IASB staff issued Agenda Paper 12 outlining the staff's view that regulatory assets and regulatory liabilities did not meet the definitions of an intangible asset under International Accounting Standard ("IAS") 38 – *Intangible Assets*, a financial liability nor a provision under IAS 37 – *Provisions, Contingent Liabilities and Contingent Assets* respectively. The utility industry immediately expressed its concern against the issuance of such a blanket prohibition under IFRS. On September 16, 2010, the IASB held a meeting to discuss Agenda Paper 12 and the overall status of the rate-regulated activities project. The IASB members remained divided on the issue and determined that the matter could not be resolved quickly. As such, the IASB decided to obtain feedback through public consultation as to the next steps that the IASB should take in relation to the rate-regulated activities project. Feedback from constituents was expected to be obtained by early 2011 and next steps for the project were expected to be determined and communicated by the second half of 2011. At this time, no further discussions are planned for this project on the IASB's work plan.

The Canadian Electricity Association ("CEA") wrote a letter to the IASB on September 28, 2010 requesting an interim standard to grandfather previous GAAP accounting practices, such as those in Canada, be developed with respect to accounting for regulatory assets and liabilities. The IASB response indicated that it would further consider an interim standard after public consultation in 2011. To date, the IASB has not approved any temporary exemption or finalized a RRA standard under IFRS.

On September 10, 2010, the Accounting Standards Board ("AcSB") granted an optional one-year deferral for IFRS adoption for entities subject to rate regulation due to the uncertainty created by the IASB in regard to RRA. To date, the IASB has not approved any temporary exemption or finalized a RRA standard under IFRS. The Corporation elected to take the optional one-year deferral of its adoption of IFRS; therefore, it continues to prepare its Consolidated Financial Statements in accordance with Canadian GAAP accounting standards in Part V of the Canadian Institute of Chartered Accountants Handbook in 2011.

On October 13, 2011, the CEA wrote a letter to the AcSB in response to the IASB's Request for Views on Agenda Consultation 2011. The CEA strongly believes that the IASB should give priority to a project on the accounting for RRA. The AcSB has also identified RRA as a key priority on the IASB's future projects agenda.

In the absence of a definitive plan to consider the issuance of a RRA standard by the IASB, the Corporation decided to evaluate the option of adopting US GAAP effective January 1, 2012 as an alternative to IFRS. The Corporation's current application of Canadian GAAP for RRA is generally consistent with US GAAP. Under US GAAP, the Corporation's financial reporting is expected to be more comparable with its current Canadian GAAP results than it would be under IFRS and is expected to facilitate comparability with other large North American utilities.

Canadian Securities Legislation

On July 8, 2011, the Corporation filed an application with the applicable Canadian securities regulatory authorities pursuant to section 5.1 of National Instrument 52-107 "Acceptable Accounting Principles and Auditing Standards", to permit the Corporation to prepare its consolidated financial statements in accordance with US GAAP without qualifying as a US Securities and Exchange Commission issuer.

On July 21, 2011, the applicable Canadian securities regulatory authorities issued a decision which gave the Corporation the option to prepare its consolidated financial statements in accordance with US GAAP for its fiscal years beginning on or after January 1, 2012, but before January 1, 2015. The decision is similar to that obtained by other Canadian rate-regulated utilities.

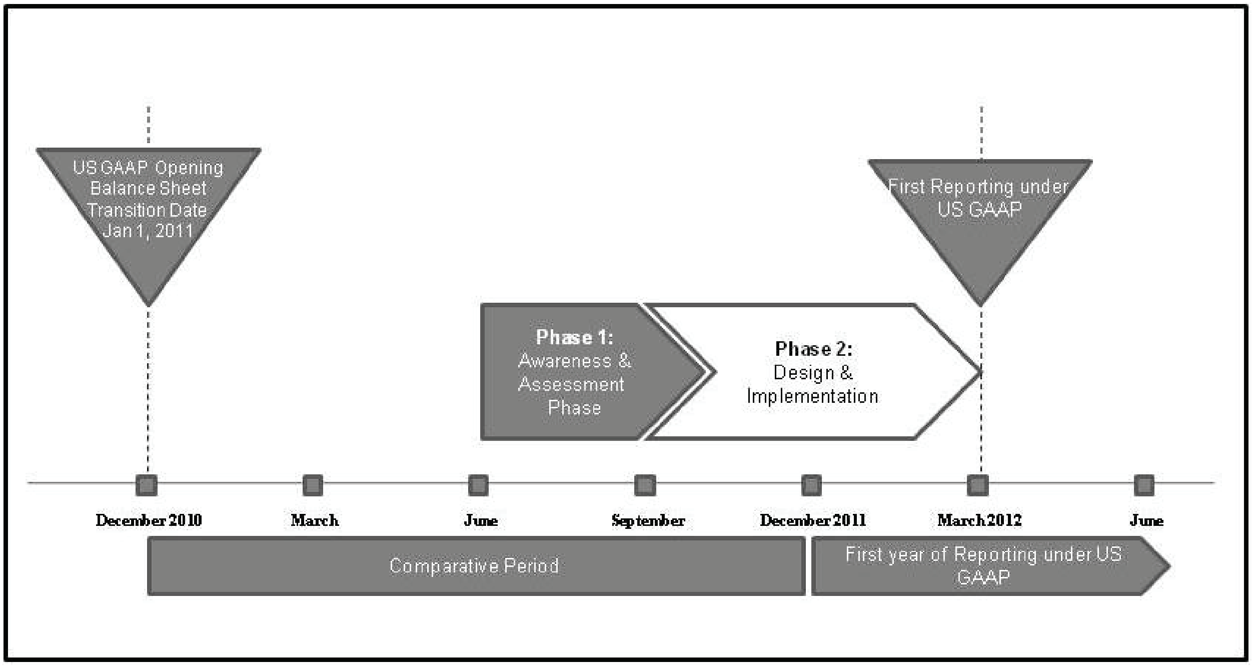
On August 26, 2011, the board of directors of the Corporation approved the adoption of US GAAP for financial reporting purposes for the year beginning on January 1, 2012. Accordingly, the Corporation plans to commence reporting under US GAAP in its first quarterly consolidated financial statements in 2012. As a result of this decision, the Corporation's IFRS conversion project efforts have been reduced. However, the work has been managed in such a way that it can effectively be restarted when a future transition to IFRS is required.

US GAAP Conversion Project

The Corporation commenced its US GAAP conversion project and established a formal project governance structure. This structure includes a steering committee consisting of senior levels of management from finance, information technology and operations, among others. External accounting advisors have been engaged to assist the US GAAP conversion project team and to provide technical accounting support as required. Regular progress reports are provided to senior executive management. The Corporation's audit committee receives periodic project updates from senior management and approves all US GAAP accounting policies. The Corporation's board of directors receives periodic project updates from senior executive management.

The Corporation's project consists of two phases:

1) the awareness and assessment phase; and
2) the design phase and implementation phase.



The Corporation has completed its awareness and initial assessment phase. During the initial assessment it was determined that the areas of accounting differences with the highest potential impact to the Corporation's future financial position and results of operations are employee benefits, PILs, financial instruments, and customers' advance deposits. The Corporation has completed its detailed assessment of accounting and disclosure differences. Based on the results of the assessment, no material differences are expected that would impact the consolidated financial statements on the date of transition to US GAAP and post US GAAP implementation. In parallel, a detailed assessment of the impact of the US GAAP conversion on the Corporation's systems, processes and controls as well as other business, regulatory and tax impacts was also conducted. During the awareness and assessment phase, the Corporation established a communication plan and a staff-training plan.

The design and implementation phase of the project is substantially completed. The activities involved in the design phase include establishing issue-specific working groups in each of the identified risk areas. The working groups are comprised of individuals from finance and operations, among others, establish key milestones such as developing recommendations, analyzing financial system and internal control impacts, developing significant accounting policies, and carrying out ongoing discussions with external consultants and auditors, in each area. Based on the outcomes of each working group, the Corporation is currently determining the final impacts of adopting US GAAP on its 2011 comparative consolidated financial statements.

The roll-out of the required changes takes place during the design and implementation phase and involves the development of new accounting policies, development of accounting manuals and the associated training for the finance and operational teams, testing the effectiveness of the changes made to systems, a simulation of the financial reporting process, preparation of opening balance sheet on transition date and related reconciliations and disclosures. Based on these changes, the Corporation updated its internal control processes and documentation. Changes to accounting policies will result in additional controls and procedures to address reporting on transition date as well as ongoing US GAAP reporting requirements. The Corporation developed and implemented the related controls and procedures to ensure the integrity of internal controls over financial reporting and disclosure controls and procedures. The updated controls and procedures will be evaluated to ensure that they are operating effectively. It is expected that the evaluation will be completed in time such that the Corporation's interim consolidated financial statements for the first quarter of 2012 will be prepared in accordance with US GAAP and applied retrospectively to the Corporation's opening US GAAP consolidated balance sheet as at January 1, 2011.

Key Activities	Current Status
Accounting policies & procedures:	
• High level review of major differences between Canadian GAAP and US GAAP. • Establish issue-specific working groups in the identified risk areas. • Detailed assessment of accounting and disclosure differences and accounting policy choices available. • Develop recommendations and accounting policies through ongoing discussions with external consultants and auditors. • Finalize new accounting policies and accounting manuals. • Continue to monitor ongoing Financial Accounting Standards Board ("FASB") projects and assess potential impacts.	• Completed the detailed assessment of accounting and disclosure differences. • All accounting policies have been developed. • All accounting policies have been approved by senior management and the audit committee. • Accounting policies and procedure manuals continue to be updated based on the FASB project developments and accounting standard updates.
Financial statements preparation:	
• Identify Canadian GAAP to US GAAP financial statement presentation differences and design interim and annual financial statement formats and related notes disclosures. • Assess impacts on comparative information. • Simulate the financial reporting process under US GAAP. • Assess ongoing impacts on the US GAAP financial statements and related disclosures.	• Developed interim and annual consolidated financial statement formats. • Substantially completed all journal entries and related account reconciliations for the comparative period. • Testing of systems related modifications are completed.
Training & communication:	
• Provide training to affected finance and operational teams, management, the board of directors, and relevant committees thereof, including the audit committee. • Develop and execute staff training plan, and roll out communication initiatives. • Continue to update audit committee and senior management for key developments in US GAAP and the potential impacts to the Corporation's consolidated financial statements.	• Completed detailed training for resources directly engaged in the changeover and general awareness training to broader group of finance and operation employees. • Completed topic-specific and relevant training to finance and operational teams on all finalized positions. Key areas include employee benefits, PILs, financial instruments, and customers' advance deposits. • Completed awareness and assessment phase closeout training sessions for all key finance and operational teams. • Continue ongoing, periodic internal and external communications on the Corporation's progress on the US GAAP project and direction. • Knowledge transfer is scheduled to roll-out in the first quarter of 2012.
Business impacts:	
• Evaluate impacts and implement necessary changes to debt covenants, internal performance measures, contracts and processes.	• Impacts to debt covenants, key financial ratios, regulatory and other business processes were identified and assessed throughout the development of accounting policies. • Amended the trust indenture agreement allowing the use of US GAAP for reporting purposes.
Information technology systems:	
• Analysis of financial systems to identify required modifications. • Test the effectiveness of the changes made to financial systems. • Ensure solution captures financial information under Canadian GAAP and US GAAP during the year of transition for comparative reporting purposes.	• Completed preliminary assessment of the IT systems impacts to accommodate the adoption of US GAAP. • Completed the implementation and testing of the required modifications to financial systems.

US GAAP Differences

Based on the results of the detailed assessment performed, the following is a summary of the key accounting areas for which significant Canadian GAAP to US GAAP differences were identified:

Risk Areas	Key Differences Canadian GAAP vs. US GAAP	Potential Key Impacts
Employee Benefits	US GAAP requires the full obligation (funded or unfunded status) of defined benefit plans to be recognized as a liability on the balance sheet and no adjustments are made for minimum funding requirements. Actuarial gains and losses are recognized in Other Comprehensive Income ("OCI") in the period in which they arise and are presented within equity as Accumulated Other Comprehensive Income ("AOCI"). Amounts presented in AOCI are subsequently reclassified to profit or loss, generally using the corridor method. Prior service costs are recognized initially in OCI in the period in which they arise and are presented within equity as AOCI. The liability for an underfunded plan must be classified as a current liability, a non-current liability or both. The current portion (determined on a plan-by-plan basis) is the amount by which the actuarial present value of benefits included in the benefit payable in the next 12 months exceeds the fair value of plan assets. Based on Accounting Standards Update No. 2011-09 on *Disclosures about an Employer's Participation in a Multi-employer Plan*, the Corporation will be required to disclose additional information on its pension plan.	All unamortized actuarial gains and unamortized prior service costs will be recognized on the consolidated balance sheet resulting in an increase of approximately $30.0 million, as at January 1, 2011, to post-employment benefits liability, with a corresponding reduction to equity presented as AOCI on the consolidated balance sheet. No significant impact to the net asset position is expected on the Corporation's consolidated balance sheet. However, given the nature of the Corporation's rate-regulated operations, the amounts presented in AOCI will be reclassified to a regulatory asset. Actuarial gains and losses and prior service costs will be recognized in OCI and presented within equity as AOCI. Since the corridor method is used under both Canadian GAAP and US GAAP, no differences will arise with respect to the recognition of actuarial gains and losses and prior service costs in profit or loss in a period. A portion of the benefit obligation will be presented as a post-employment benefits current liability on the consolidated balance sheet. The measurement date of the actuarial valuation is required to be as of the reporting date of the Corporation, therefore, a reconciliation for the one day difference may be required.
PILs	US GAAP requires deferred income taxes to be calculated based on enacted tax rates. US GAAP states that the recognition of an investment tax credit ("ITC") as a reduction of income tax expense in the year in which the credit arises is acceptable. US GAAP does not provide specific guidance applicable to government grants.	The calculation of PILs is not expected to be impacted. Certain types of ITCs which are government grants that are refundable in nature will continue to be applied as a reduction against the related expense in the profit or loss. Other ITC's which are non-refundable in nature will be recognized as a reduction of income tax expense.
Financial Instruments	US GAAP requires financing fees to be reported on the balance sheet as a deferred charge; hence, financing fees are presented on a gross basis.	It is expected that financing fees associated with long-term debt will no longer be netted against the principal balance of the related long-term debt. The impact of this change is an increase of approximately $4.9 million, as at January 1, 2011, to deferred charges with a corresponding increase to long-term debt.
Customers' Advance Deposits	Under US GAAP, customers' advance deposits are classified as current liabilities if they are due on demand or will be due on demand within one year from the end of the reporting period. As such, they are classified as a current liability even if refunds of the deposits are not to be expected within that period.	It is expected that there will be a reclassification for customers' advance deposits from non-current to current liability under US GAAP. The impact of this change is an increase of approximately $31.8 million, as at January 1, 2011, to current liabilities with a corresponding decrease to non-current liabilities.

OEB Review Process

On June 13, 2011, the OEB issued an Addendum to Report of the Board: *Implementing International Financial Reporting Standards in an Incentive Rate Mechanism Environment.* Specifically, the OEB addressed the use of US GAAP in rate applications. The OEB is encouraging utilities adopting US GAAP to file a letter in advance of making the rate application, stating the intention to file under US GAAP. The utility must be able to demonstrate its eligibility under the relevant securities legislation to report financial information under US GAAP, and identify the benefits and potential disadvantages of adopting US GAAP for customers.

On August 19, 2011, LDC filed a letter with the OEB stating its intention to adopt US GAAP as the basis for the calculation of electricity distribution rates starting in 2012 in accordance with the guidelines provided by the OEB. In the OEB guidelines, the OEB indicated to Ontario utilities that it would permit the use of US GAAP for the calculation of electricity distribution rates if such utilities receive approval from the Ontario Securities Commission and if it benefits electricity distribution consumers.

On December 21, 2011, the OEB issued a letter requesting comments on the revised AP Handbook. The proposed revisions made in the AP Handbook are primarily to reflect the transition to IFRS. Distributors reporting under an alternative accounting framework will be required to report using the alternative accounting standard, but to also include the accounting procedures or requirements that the OEB has stipulated. On January 30, 2012, LDC provided its comments through a joint submission with the Coalition of Large Distributors as well as its own letter to address its entity-specific issues.

On February 28, 2012, LDC submitted a letter to the OEB requesting a deferral account to record the accounting differences between Canadian GAAP and US GAAP.

To date, there are no formal clear guidelines from the OEB regarding the treatment of the differences between Canadian GAAP and IFRS or US GAAP in the electricity distribution rates application process. However, considering the similarities between Canadian GAAP currently used by LDC to derive electricity distribution rates and US GAAP, the Corporation does not believe that the adoption of US GAAP will have a material impact on LDC's electricity distribution rates.

Selected Annual Information

The following table sets forth selected annual financial information of the Corporation for the three years ended December 31, 2011, 2010 and 2009. This information has been derived from the Consolidated Financial Statements.

Selected Annual Consolidated Financial Information
(in thousands of dollars)

Year Ended December 31,[1]	**2011 $**	**2010 $**	**2009 $**
Net revenues	570,758	549,402	504,266
Operating expenses	243,547	223,326	208,834
Net income	95,932	66,125	42,133
As at December 31,	**2011 $**	**2010 $**	**2009 $**
Total assets[2]	3,455,777	3,338,614	3,059,227
Total debentures[2] [3]	1,463,514	1,409,837	720,475
Promissory note payable	-	-	490,115
Shareholder's equity[2]	1,102,248	1,039,379	998,254
Dividends[4]	33,063	25,000	25,170

Notes:

(1) See "Results of Operations" for further details on net revenues, operating expenses and net income.
(2) See "Financial Position" for further details of significant changes in assets, debentures and shareholder's equity.
(3) Total debentures include current and long-term debentures.
(4) See "Dividends" for further details.

Additional Information

Additional information with respect to the Corporation (including its annual information form) is available at www.sedar.com.

Toronto, Canada

March 2, 2012

CONSOLIDATED FINANCIAL STATEMENTS
DECEMBER 31, 2011

Consolidated Financial Statements

DECEMBER 31, 2011

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TORONTO HYDRO Corporation

MANAGEMENT'S REPORT

The accompanying Consolidated Financial Statements have been prepared by management of Toronto Hydro Corporation (the "Corporation"), who are responsible for the integrity, consistency and reliability of the information presented. The Consolidated Financial Statements have been prepared in accordance with Canadian generally accepted accounting principles and applicable securities legislation.

The preparation of the Consolidated Financial Statements necessarily involves the use of estimates and assumptions based on management's judgments, particularly when transactions affecting the current accounting period cannot be finalized with certainty until future periods. Estimates and assumptions are based on historical experience, current conditions and various other assumptions believed to be reasonable in the circumstances, with critical analysis of the significant accounting policies followed by the Corporation as described in Note 3 to the Consolidated Financial Statements. The preparation of the Consolidated Financial Statements includes information regarding the estimated impact of future events and transactions. Actual results in the future may differ materially from the present assessment of this information because future events and circumstances may not occur as expected. The Consolidated Financial Statements have been prepared within reasonable limits of materiality in light of information available up to March 2, 2012.

In meeting its responsibility for the reliability of financial information, management maintains and relies on a comprehensive system of internal control and internal audit, which is designed to provide reasonable assurance that the financial information is relevant, reliable and accurate, and that the Corporation's assets are safeguarded and transactions are properly authorized and executed. The system includes formal policies and procedures and appropriate delegation of authority and segregation of responsibilities within the organization. An internal audit function evaluates the effectiveness of these internal controls consistent with its annual audit plan and reports its findings to management and the Audit Committee of the Corporation, as required.

The Consolidated Financial Statements have been examined by KPMG LLP, independent external auditors appointed by the Corporation's shareholder. The external auditors' responsibility is to express their opinion on whether the Consolidated Financial Statements are fairly presented in accordance with generally accepted accounting principles in Canada. The attached Independent Auditors' Report outlines the scope of their examination and their opinion.

The Board of Directors, through its Audit Committee, is responsible for overseeing management in the performance of its financial reporting and internal controls. The Audit Committee is composed of independent directors and meets periodically with management, the internal auditors and the external auditors to discuss internal controls over the financial reporting process, auditing matters and financial reporting issues, to satisfy itself that each group has properly discharged its respective responsibility and to review the Consolidated Financial Statements before recommending approval by the Board of Directors. The Audit Committee also considers, for review by the Board of Directors and approval by the shareholder, the appointment of the external auditors. The external auditors have direct and full access to the Audit Committee, with and without the presence of management, to discuss their audit and their findings as to the integrity of the financial reporting and the effectiveness of the system of internal controls.

On behalf of Toronto Hydro Corporation's management:

Anthony Haines	Jean-Sebastien Couillard
President and Chief Executive Officer	Chief Financial Officer

KPMG

KPMG LLP
Chartered Accountants
Bay Adelaide Centre
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Toronto ON M5H 2S5

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INDEPENDENT AUDITORS' REPORT

To the Shareholder of Toronto Hydro Corporation

We have audited the accompanying consolidated financial statements of Toronto Hydro Corporation, which comprise the consolidated balance sheet as at December 31, 2011, the consolidated statements of income, retained earnings and cash flows for the year then ended, and notes, comprising a summary of significant accounting policies and other explanatory information.

Management's Responsibility for the Consolidated Financial Statements

Management is responsible for the preparation and fair presentation of these consolidated financial statements in accordance with Canadian generally accepted accounting principles, and for such internal control as management determines is necessary to enable the preparation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

Auditors' Responsibility

Our responsibility is to express an opinion on these consolidated financial statements based on our audit. We conducted our audit in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the consolidated financial statements. The procedures selected depend on our judgment, including the assessment of the risks of material misstatement of the consolidated financial statements, whether due to fraud or error. In making those risk assessments, we consider internal control relevant to the entity's preparation and fair presentation of the consolidated financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the consolidated financial statements present fairly, in all material respects, the consolidated financial position of Toronto Hydro Corporation as at December 31, 2011, and its consolidated financial performance and its consolidated cash flows for the year then ended in accordance with Canadian generally accepted accounting principles.

Other matter

The consolidated financial statements of Toronto Hydro Corporation as at and for the year ended December 31, 2010 were audited by another auditor who expressed an unmodified opinion on those statements on March 11, 2011.

KPMG LLP

Chartered Accountants, Licensed Public Accountants

Toronto, Canada

March 2, 2012

TORONTO HYDRO Corporation

CONSOLIDATED BALANCE SHEETS

[in thousands of dollars]

As at December 31	2011 $	2010 $
ASSETS		
Current		
Cash and cash equivalents	**154,256**	330,151
Investments	**34,002**	-
Accounts receivable, net of allowance for doubtful accounts *[note 16[b]]*	**183,272**	168,988
Unbilled revenue *[note 16[b]]*	**262,058**	287,893
Payments in lieu of corporate taxes receivable	**11,312**	6,729
Inventories *[note 4]*	**6,891**	7,501
Prepaid expenses	**4,487**	4,048
Total current assets	**656,278**	805,310
Property, plant and equipment, net *[note 5]*	**2,399,497**	2,128,777
Intangible assets, net *[note 6]*	**112,982**	85,996
Regulatory assets *[note 7]*	**77,322**	85,113
Other assets *[note 8]*	**7,331**	7,518
Future income tax assets *[note 18]*	**202,367**	225,900
Total assets	**3,455,777**	3,338,614
LIABILITIES AND SHAREHOLDER'S EQUITY		
Current		
Accounts payable and accrued liabilities *[note 16[b]]*	**412,412**	373,543
Other liabilities *[note 10]*	**22,290**	19,733
Deferred revenue	**13,359**	1,418
Debentures *[note 11]*	**-**	245,057
Total current liabilities	**448,061**	639,751
Long-term liabilities		
Debentures *[note 11]*	**1,463,514**	1,164,780
Post-employment benefits *[note 12]*	**179,541**	169,897
Regulatory liabilities *[note 7]*	**210,280**	273,706
Other liabilities *[note 13]*	**11,301**	634
Asset retirement obligations *[note 14]*	**4,902**	5,005
Customers' advance deposits	**35,930**	45,462
Total long-term liabilities	**1,905,468**	1,659,484
Total liabilities	**2,353,529**	2,299,235
Commitments, contingencies and subsequent events *[notes 21, 22 and 25]*		
Shareholder's equity		
Share capital *[note 19]*	**567,817**	567,817
Retained earnings	**534,431**	471,562
Total shareholder's equity	**1,102,248**	1,039,379
Total liabilities and shareholder's equity	**3,455,777**	3,338,614

ON BEHALF OF THE BOARD:

CR Copeland

Clare R. Copeland, Director

Brian Chu

Brian Chu, Director

The accompanying notes are an integral part of the consolidated financial statements.

CONSOLIDATED STATEMENTS OF INCOME

[in thousands of dollars, except for per share amounts]

Year ended December 31	**2011** **$**	**2010** **$**
Revenues	**2,809,258**	2,611,671
Costs		
Purchased power and other	**2,238,500**	2,062,269
Operating expenses	**243,547**	223,326
Depreciation and amortization	**151,022**	169,408
	2,633,069	2,455,003
Income before the following:	**176,189**	156,668
Net financing charges	**(75,324)**	(71,150)
Gain on disposals of property, plant and equipment *[note 5]*	**3,885**	3,767
Change in fair value of investments	**-**	2,420
Income before provision for payments in lieu of corporate taxes	**104,750**	91,705
Provision for payments in lieu of corporate taxes *[note 18]*	**8,818**	25,580
Net income	**95,932**	66,125
Basic and fully diluted net income per share *[note 23]*	**95,932**	66,125

CONSOLIDATED STATEMENTS OF RETAINED EARNINGS

[in thousands of dollars]

Year ended December 31	**2011** **$**	**2010** **$**
Retained earnings, beginning of year	**471,562**	430,437
Net income	**95,932**	66,125
Dividends *[notes 19 and 20]*	**(33,063)**	(25,000)
Retained earnings, end of year	**534,431**	471,562

The accompanying notes are an integral part of the consolidated financial statements.

CONSOLIDATED STATEMENTS OF CASH FLOWS

[in thousands of dollars]

Year ended December 31	**2011** **$**	**2010** $
OPERATING ACTIVITIES		
Net income	**95,932**	66,125
Adjustments for non-cash items		
Depreciation and amortization	**151,022**	169,408
Change in fair value of investments	**-**	(2,420)
Net change in other assets and liabilities	**(1,312)**	5,051
Payments in lieu of corporate taxes	**(4,583)**	9,203
Post-employment benefits	**9,644**	8,549
Future income taxes *[note 18]*	**(601)**	871
Gain on disposals of property, plant and equipment *[note 5]*	**(3,885)**	(3,767)
Changes in non-cash working capital balances		
Increase in accounts receivable	**(14,284)**	(18,193)
Decrease in unbilled revenue	**25,835**	7,754
Decrease (increase) in inventories	**610**	(1,277)
Increase in prepaid expenses	**(439)**	(717)
Increase in accounts payable and accrued liabilities	**39,093**	40,109
Increase (decrease) in deferred revenue	**13,316**	(378)
Net cash provided by operating activities	**310,348**	280,318
INVESTING ACTIVITIES		
Purchase of property, plant and equipment *[note 5]*	**(384,262)**	(362,397)
Purchase of intangible assets *[note 6]*	**(52,805)**	(28,387)
Purchase of investments	**(84,041)**	-
Proceeds from investments	**50,000**	50,350
Net change in regulatory assets and liabilities	**(31,725)**	(16,011)
Proceeds on disposals of property, plant and equipment	**4,974**	8,861
Net cash used in investing activities	**(497,859)**	(347,584)
FINANCING ACTIVITIES		
Dividends paid *[notes 19 and 20]*	**(33,063)**	(25,000)
Proceeds from debentures *[note 11]*	**297,950**	198,493
Repayment of debentures *[note 11]*	**(245,057)**	-
Increase (decrease) in customers' advance deposits	**(8,214)**	12,554
Net cash provided by financing activities	**11,616**	186,047
Net increase (decrease) in cash and cash equivalents during the year	**(175,895)**	118,781
Cash and cash equivalents, beginning of year	**330,151**	211,370
Cash and cash equivalents, end of year	**154,256**	330,151
Supplementary cash flow information		
Total interest paid	**79,552**	71,248
Payments in lieu of corporate taxes	**10,299**	15,061

The accompanying notes are an integral part of the consolidated financial statements.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

[all tabular amounts in thousands of dollars]

December 31, 2011

1. INCORPORATION

On June 23, 1999, Toronto Hydro Corporation [the "Corporation"] was incorporated under the *Business Corporations Act* (Ontario) [the "OBCA"] and is wholly-owned by the City of Toronto [the "City"]. The incorporation was required in accordance with the provincial government's *Electricity Act, 1998* (Ontario) ["Electricity Act"].

The Corporation supervises the operations of, and provides corporate, management services and strategic direction to two subsidiaries incorporated under the OBCA and wholly-owned by the Corporation:

[i] Toronto Hydro-Electric System Limited ["LDC"] (incorporated June 23, 1999) – distributes electricity to customers located in the City and is subjected to rate regulation. LDC is also engaged in the delivery of Conservation and Demand Management ["CDM"] activities; and

[ii] Toronto Hydro Energy Services Inc. ["TH Energy"] (incorporated June 23, 1999) – provides street lighting services.

The principal business of the Corporation and its subsidiaries is the distribution of electricity by LDC.

2. REGULATION

In April 1999, the government of Ontario began restructuring the Province of Ontario ["Ontario"]'s electricity industry. Under regulations passed pursuant to the restructuring, LDC and other electricity distributors have been purchasing their electricity from the wholesale market administered by the Independent Electricity System Operator ["IESO"] and recovering the costs of electricity and certain other costs at a later date in accordance with procedures mandated by the Ontario Energy Board [the "OEB"].

The OEB has regulatory oversight of electricity matters in Ontario. The *Ontario Energy Board Act, 1998* (Ontario) [the "OEB Act"] sets out the OEB's authority to issue a distribution licence which must be obtained by owners or operators of an electricity distribution system in Ontario. The OEB prescribes licence requirements and conditions including, among other things, specified accounting records, regulatory accounting principles, separation of accounts for separate businesses and filing process requirements for rate-setting purposes.

The OEB's authority and responsibilities include the power to approve and fix rates for the transmission and distribution of electricity, the power to provide continued rate protection for rural and remote electricity customers and the responsibility for ensuring that electricity distribution companies fulfill their obligations to connect and service customers.

Regulatory developments in Ontario's electricity industry, including current and possible future consultations between the OEB and interested stakeholders, may affect LDC's electricity distribution rates and other permitted recoveries in the future.

LDC is required to charge its customers for the following amounts (all of which, other than distribution charges, represent a pass through of amounts payable to third parties):

[i] *Distribution Charges*. Distribution charges are designed to recover the costs incurred by LDC in delivering electricity to customers and the OEB-allowed rate of return. Distribution charges are regulated by the OEB and are comprised of a fixed charge and a usage-based (consumption) charge. The volume of electricity consumed by LDC's customers during any period is governed by events largely outside LDC's control (principally, sustained periods of hot or cold weather which increase the consumption of electricity and sustained periods of moderate weather which decrease the consumption of electricity).

[ii] *Electricity Price and Related Regulated Adjustments*. The electricity price and related regulated adjustments represent a pass through of the commodity cost of electricity.

[iii] *Retail Transmission Rate*. The retail transmission rate represents a pass through of wholesale costs incurred by distributors in respect of the transmission of electricity from generating stations to local areas. Retail transmission rates are regulated by the OEB.

[iv] *Wholesale Market Service Charge*. The wholesale market service charge represents a pass through of various wholesale market support costs. Retail rates for the recovery of wholesale market service charges are regulated by the OEB.

LDC is required to satisfy and maintain prudential requirements with the IESO, which include credit support with respect to outstanding market obligations in the form of letters of credit, cash deposits or guarantees from third parties with prescribed credit ratings.

a) Electricity Distribution Rates

LDC's electricity distribution rates are typically effective from May 1 to April 30 of the following year. Accordingly, LDC's distribution revenue for the first four months of 2011 was based on the electricity distribution rates approved for the May 1, 2010 to April 30, 2011 rate year [the "2010 Rate Year"], and the distribution revenue for the remainder of 2011 and for the first four months of 2012 are and will be based on electricity distribution rates approved for the May 1, 2011 to April 30, 2012 rate year [the "2011 Rate Year"].

LDC's electricity distribution rates for the 2010 Rate Year and the 2011 Rate Year were determined through an application under the cost of service framework. The cost of service framework sets electricity distribution rates using a detailed examination of evidence and an assessment of the costs incurred by an electricity distributor to provide its service to its customers.

On April 9, 2010, the OEB issued its decision regarding LDC's electricity distribution rates for the 2010 Rate Year. The decision provided for a distribution revenue requirement and rate base of $518,700,000 and $2,140,700,000, respectively. In addition, the decision provided for capital program spending levels and operating, maintenance and administration spending levels of $350,000,000 and $204,100,000, respectively.

On July 7, 2011, the OEB issued its decision regarding LDC's electricity distribution rates for the 2011 Rate Year. The decision provided for a distribution revenue requirement and rate base of $522,044,000 and $2,298,227,000, respectively. In addition, the decision provided for capital program spending levels and operating, maintenance and administration spending levels of $378,800,000 and $238,000,000, respectively.

On August 26, 2011, LDC filed a rate application, following the cost of service framework, with the OEB seeking approval of separate and successive revenue requirements and corresponding electricity distribution rates for three rate years commencing on May 1, 2012, May 1, 2013 and May 1, 2014 [the "2012-2014 Rate Application"]. The requested distribution revenue requirements for these rate years were $571,369,000, $639,492,000, and $712,777,000, respectively, and the expected rate bases for these rate years were $2,636,291,000, $3,053,499,000, and $3,503,165,000, respectively.

Pursuant to the incentive regulation mechanism framework, the OEB established, as a preliminary issue in the 2012-2014 Rate Application, that it would consider the question of whether the application filed by LDC was acceptable or whether it should be dismissed. In particular, the OEB established that in order for it to find that LDC's 2012-2014 Rate Application was acceptable, LDC would be required to show why and how LDC cannot adequately manage its resources and financial needs under the incentive regulation mechanism framework. The incentive regulation mechanism framework provides for an annual adjustment to an electricity distributor's rates based on a formulaic calculation with no direct examination of evidence regarding the electricity distributor's actual costs and infrastructure needs.

LDC filed evidence supporting its position for electricity distribution rates to be set under the cost of service framework as part of its 2012-2014 Rate Application. In particular, LDC provided evidence that it cannot adequately manage its resources and financial needs under the incentive regulation mechanism framework. The OEB established a process by which a portion of LDC's evidence was tested during an oral hearing held in November 2011 *[note 25[b]]*.

b) Street Lighting Activities

On June 15, 2009, the Corporation filed an application with the OEB seeking an electricity distribution licence for a new wholly-owned legal entity to which the Corporation intended to transfer the street lighting assets of TH Energy. Concurrently, the Corporation filed another application with the OEB seeking approval for the merger of LDC and the new legal entity. The main objective of these applications was to transfer the street lighting assets to the regulated electricity distribution activities of LDC to increase the overall safety of the related infrastructure.

On February 11, 2010, the OEB issued its decision in regard to these applications. In its decision, the OEB agreed that, under certain conditions, the treatment of certain types of street lighting assets as regulated assets is justified. The OEB ordered the Corporation to provide a detailed valuation of the street lighting assets and to perform an operational review to determine which street lighting assets could become regulated assets. The Corporation performed a detailed asset operational review and financial valuation of the street lighting assets, which was submitted to the OEB on January 31, 2011.

On August 3, 2011, the OEB issued its final decision allowing the transfer of a portion of the street lighting assets to the new wholly-owned legal entity, and for LDC to amalgamate with the new legal entity *[note 25[a]]*.

c) Conservation and Demand Management Activities

On March 31, 2010, the Minister of Energy and Infrastructure of Ontario, under the guidance of sections 27.1 and 27.2 of the OEB Act, directed the OEB to establish CDM targets to be met by electricity distributors. Accordingly, on November 12, 2010, the OEB amended LDC's distribution licence to require LDC, as a condition of its licence, to achieve 1,304 Gigawatt-Hours of energy savings and 286 Megawatts of summer peak demand savings, over the period beginning January 1, 2011 through December 31, 2014.

Effective January 1, 2011, LDC entered into an agreement with the Ontario Power Authority ["OPA"] to deliver CDM programs in the amount of approximately $50,000,000 extending from January 1, 2011 to December 31, 2014. As at December 31, 2011, LDC received approximately $19,875,000 from the OPA for the delivery of CDM programs. All programs to be delivered are fully funded and paid in advance by the OPA. These programs are expected to support the achievement of the mandatory CDM targets described above.

On January 10, 2011, LDC filed an application with the OEB seeking an order granting approval of funding for CDM programs specific to its customer base. LDC requested funding for eight specific CDM programs amounting to $50,700,000. On July 12, 2011, the OEB issued its decision regarding the CDM programs of LDC. In its decision, the OEB approved with modifications two of the eight programs for a total funding of $5,320,000. The modifications directed by the OEB included changes to the term and nature of those two programs. The OEB did not approve the other six programs as it considered them to be duplicative of existing CDM programs already funded by the OPA.

On August 3, 2011, LDC filed a letter with the OEB informing them that, due to the modified terms and nature of the two approved programs, LDC's revised economic assessment showed these two programs to be uneconomic, and that they would not be implemented. Accordingly, LDC expects to continue to work with the OPA to expand the roster of current CDM programs in order to achieve its mandated CDM targets.

d) Contact Voltage

On December 10, 2009, the OEB issued an initial decision in regard to the costs incurred in 2009 for the remediation of safety issues related to contact voltage relating to LDC's electricity distribution infrastructure. The decision provided for the recovery of allowable actual expenditures incurred above the amount deemed as controllable expenses in LDC's 2009 approved electricity distribution rates. At the time of the decision, the Corporation estimated the allowable recovery of costs at $9,050,000.

On October 29, 2010, the OEB issued a second decision in the matter, following further review of costs incurred by LDC. In this decision, the OEB deemed the balance allowable for recovery at $5,296,000. The variance from the Corporation's original estimate is mainly due to the OEB's interpretation of the definition of controllable expenses used to determine the final allowable recovery. In connection with this decision from the OEB, the Corporation revised its recovery estimate for contact voltage costs, resulting in an increase in operating expenses of $3,754,000 in 2010. On November 18, 2010, LDC filed a motion to review the decision with the OEB seeking an amendment to allow for recovery in accordance with the initial decision rendered on December 10, 2009. On March 25, 2011, the OEB issued its decision on the LDC motion, denying the requested additional recovery.

3. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

The consolidated financial statements of the Corporation have been prepared in accordance with Canadian generally accepted accounting principles ["GAAP"], including accounting principles prescribed by the OEB in the handbook "Accounting Procedures Handbook for Electric Distribution Utilities" ["AP Handbook"], are presented in Canadian dollars and reflect the significant accounting policies summarized below:

a) Basis of consolidation

The consolidated financial statements include the accounts of the Corporation and its wholly-owned subsidiaries. All significant intercompany balances and transactions have been eliminated.

b) Regulation

The following regulatory treatments have resulted in accounting treatments which differ from Canadian GAAP for enterprises operating in an unregulated environment:

Regulatory Assets and Liabilities

In accordance with Canadian GAAP, the Corporation currently follows specific accounting policies unique to a rate-regulated business. Under rate-regulated accounting ["RRA"], the timing and recognition of certain expenses and revenues may differ from those otherwise expected under Canadian GAAP in order to appropriately reflect the economic impact of regulatory decisions regarding the Corporation's regulated revenues and expenditures. These timing differences are recorded as regulatory assets and regulatory liabilities on the Corporation's consolidated balance sheets and represent current rights and obligations regarding cash flows expected to be recovered from or refunded to customers, based on decisions and approvals by the OEB. These assets and liabilities can be recognized for rate-setting and financial reporting purposes only if the OEB directs the relevant regulatory treatment or if future OEB direction is judged to be probable. In the event that the disposition of these balances was assessed to no longer be probable, the balances would be recorded in the Corporation's consolidated statements of income in the period that the assessment is made. The measurement of regulatory assets and liabilities is subject to certain estimates and assumptions, including assumptions made in the interpretation of the regulation and the OEB's decisions.

Contributions in aid of construction

Capital contributions received from outside sources are used to finance additions to property, plant and equipment of LDC. According to the AP Handbook, capital contributions received are treated as a "credit" to property, plant and equipment. The amount is subsequently depreciated by a charge to accumulated depreciation and a credit to depreciation expense at an equivalent rate to that used for the depreciation of the related property, plant and equipment.

Allowance for funds used during construction

The AP Handbook provides for the inclusion of an Allowance for Funds Used During Construction ["AFUDC"] when capitalizing construction-in-progress assets, until such time as the asset is substantially complete. A concurrent credit of the same amount is made to net financing charges when the allowance is capitalized. The interest rate for capitalization is prescribed by the OEB and modified on a periodic basis, and is applied to the balance of the construction-in-progress assets on a simple interest basis. The interest rate for capitalization, for the period from January 1 to September 30, 2011, was 4.29%, and from October 1, 2011 to December 31, 2011, was 3.92%. AFUDC is included in property, plant and equipment, intangible assets, and construction-in-progress assets for financial reporting purposes, charged to operations through depreciation and amortization expense over the service life of the related assets and recovered through future revenue.

c) Cash and cash equivalents

Cash and cash equivalents include cash in bank accounts and short-term investments with terms to maturity of 90 days or less from their date of acquisition.

d) Investments

Investments with terms to maturity of greater than 90 days from their date of acquisition are classified as held to maturity and included in current assets.

e) Inventories

Inventories consist primarily of small consumable materials mainly related to the maintenance of the electricity distribution infrastructure. The Corporation classifies all major construction related components of its electricity distribution system infrastructure to property, plant and equipment. Once capitalized, these items are not depreciated until they are put into service. Inventories are carried at the lower of cost and net realizable value, with cost determined on an average cost basis net of a provision for obsolescence.

f) Property, plant and equipment

Property, plant and equipment are stated at cost and are removed from the accounts at the end of their estimated average service lives, except in those instances where specific identification allows their removal at retirement or disposition.

In the event that facts and circumstances indicate that property, plant and equipment may be impaired, an evaluation of recoverability is performed. For purposes of such an evaluation, the estimated future undiscounted cash flows associated with the asset are compared to the carrying amount of the asset to determine if a write-down is required. The impairment loss is measured as the amount by which the carrying amount of the asset exceeds its fair value, which is determined by the estimated future discounted cash flows.

Effective January 1, 2011, the Corporation revised its estimates of useful lives of certain items of property, plant and equipment following a detailed review and analysis supported by external third-party evidence. These changes in estimates have been accounted for on a prospective basis in the consolidated financial statements effective January 1, 2011.

Effective January 1, 2011, the Corporation revised its estimates of burden rates of certain items of property, plant and equipment following a detailed review and analysis of all the components included in such burden rates. These changes in estimates of burden rates include changes in the allocation of engineering and administration costs, changes in the calculation of standard labour rates, and changes in the calculation of materials handling costs. These changes in estimates have been accounted for on a prospective basis in the consolidated financial statements effective January 1, 2011.

The changes discussed above were reflected in the 2011 electricity distribution rates approved by the OEB on July 7, 2011 *[note 2[a]]*. Accordingly, these changes decreased distribution revenues by approximately $24,600,000, increased operating expenses by approximately $22,000,000, decreased depreciation expenses by approximately $33,000,000 and decreased Payments in Lieu of Corporate Taxes ["PILs"] by approximately $13,600,000 for the year ended December 31, 2011 and are expected to impact depreciation expenses proportionately in future periods.

[all tabular amounts in thousands of dollars]

Depreciation is provided on a straight-line basis over the estimated service lives at the following annual rates:

	2011	2010
Distribution lines	1.7% to 5.0%	2.5% to 25.0%
Transformers	3.3% to 5.0%	3.3% to 4.0%
Stations	2.5% to 10.0%	2.5% to 6.7%
Meters	2.5% to 6.7%	2.9% to 6.7%
Buildings	1.3% to 5.0%	2.0%
Rolling stock	12.5% to 25.0%	12.5% to 33.3%
Other capital assets	4.0% to 20.0%	4.0% to 20.0%
Assets under capital lease	14.3% to 25.0%	25.0%
Equipment and tools	10.0% to 16.7%	10.0% to 16.7%
Computer hardware	16.7% to 25.0%	20.0% to 25.0%
Communications	10.0% to 20.0%	10.0% to 20.0%

Construction in progress relate to assets not currently in use and therefore are not depreciated.

g) Intangible assets

Intangible assets are stated at cost. Amortization is provided on a straight-line basis over their estimated service lives at the following annual rates:

	2011	2010
Computer software	20.0% to 25.0%	20.0%
Contributions	4.0%	4.0%

Software in development and contributions for work in progress relate to assets not currently in use and therefore are not amortized.

h) Deferred debt issue costs

Debt issue costs arising from the Corporation’s debenture offerings are recorded against the principal amount of the debentures. The debentures are accreted back to their face value using the effective interest rate method over the remaining period to maturity.

i) Workplace Safety and Insurance Act

The Corporation is a Schedule 1 employer for workers' compensation under the *Workplace Safety and Insurance Act, 1997* (Ontario) [the “WSIA”]. As a Schedule 1 employer under the WSIA, the Corporation is required to pay annual premiums into an insurance fund established under the WSIA and recognizes expenses based on funding requirements.

j) Revenue recognition

Revenues from the sale of electricity are recorded on a basis of cyclical billings and also include unbilled revenues accrued in respect of electricity delivered but not yet billed.

Other revenues, which include revenues from electricity distribution related services and revenues from the delivery of street lighting services, are recognized as the services are rendered.

k) Financial instruments

At inception, all financial instruments which meet the definition of a financial asset or financial liability are to be recorded at fair value, unless fair value cannot be reliably determined. Gains and losses related to the measurement of financial instruments are reported in the consolidated statements of income. Subsequent measurement of each financial instrument will depend on the balance sheet classification elected by the Corporation. The fair value of a financial instrument is the amount of consideration that would be agreed upon in an arm's length transaction between willing parties.

The following summarizes the accounting classification the Corporation has elected to apply to each of its significant categories of financial instruments:

Cash equivalents and short-term investments	Investments Held to Maturity
Investments	Investments Held to Maturity
Accounts receivable and unbilled revenue	Loans and Receivables
Accounts payable and accrued liabilities	Other Financial Liabilities
Obligations under capital lease	Other Financial Liabilities
Customers' advance deposits	Other Financial Liabilities
Debentures	Other Financial Liabilities

The Corporation uses the following methods and assumptions to estimate the fair value of each class of financial instruments for which carrying amounts are included in the consolidated balance sheet:

- Cash equivalents, comprising short-term investments, are classified as "Investments Held to Maturity" and are measured at amortized cost, which, upon initial recognition, is considered equivalent to fair value. The carrying amounts approximate fair value because of the short maturity of these instruments.
- Investments are classified as "Investments Held to Maturity" and are measured at amortized cost, which, upon initial recognition, is considered equivalent to fair value. The carrying amounts approximate fair value because of the short maturity of these instruments.
- Accounts receivable and unbilled revenue are classified as "Loans and Receivables" and are measured at amortized cost, which, upon initial recognition, are considered equivalent to fair value. Subsequent measurements are recorded at amortized cost using the effective interest rate method. The carrying amounts approximate fair value because of the short maturity of these instruments.
- Accounts payable and accrued liabilities are classified as "Other Financial Liabilities" and are initially measured at their fair value. Subsequent measurements are recorded at amortized cost using the effective interest rate method. The carrying amounts approximate fair value because of the short maturity of these instruments.

- Obligations under capital lease are classified as "Other Financial Liabilities" and are initially measured at their fair value. Subsequent measurements are based on discounted cash flow analysis and approximate their carrying values as management believes that the fixed interest rates are representative of current market rates.
- Customers' advance deposits are classified as "Other Financial Liabilities" and are initially measured at their fair value. Subsequent measurements are recorded at amortized cost using the effective interest rate method. The carrying amounts approximate fair value because of the short maturity of the current portion, and the discounted long-term portion approximates the carrying value, taking into account interest accrued on the outstanding balance.
- Debentures are classified as "Other Financial Liabilities" and are initially measured at their fair value. The carrying amounts of the debentures are carried at amortized cost, based on an initial fair value as determined at the time using quoted market price for similar debt instruments. The fair value of the debentures is calculated by discounting the related cash flows at the estimated yield to maturity of similar debt instruments *[note 16]*. While the Corporation has the option to redeem some or all of the debentures at its discretion, this option has no value and has not been recorded in the consolidated financial statements.

l) Fair value measurements

The Corporation utilizes valuation techniques that maximize the use of observable inputs and minimize the use of unobservable inputs when measuring fair value. A fair value hierarchy exists that prioritizes observable and unobservable inputs used to measure fair value. Observable inputs reflect market data obtained from independent sources, while unobservable inputs reflect the Corporation's assumptions with respect to how market participants would price an asset or liability. The fair value hierarchy includes three levels of inputs that may be used to measure fair value:

- Level 1 – Unadjusted quoted prices in active markets for identical assets or liabilities. An active market for the asset or liability is a market in which transactions for the asset or liability occur with sufficient frequency and volume to provide pricing information on an ongoing basis;
- Level 2 – Observable inputs other than level 1 prices, such as quoted prices for similar assets or liabilities; quoted prices in markets that are not active; or other inputs that are observable or can be corroborated by observable market data for substantially the full term of the assets or liabilities; and
- Level 3 – Unobservable inputs that are supported by little or no market activity and that are significant to the fair value of the assets or liabilities.

m) Employee future benefits

Pension plan

The Corporation provides a pension plan for its full-time employees through the Ontario Municipal Employees Retirement System ["OMERS"]. OMERS is a multi-employer, contributory, defined benefit pension plan established in 1962 by Ontario for employees of municipalities, local boards and school boards. Both participating employers and employees are required to make plan contributions based on participating employees' contributory earnings. The Corporation recognizes the expense related to this plan as contributions are made.

Employee future benefits other than pension

Employee future benefits other than pension provided by the Corporation include medical, dental and life insurance benefits, and accumulated sick leave credits. These plans provide benefits to employees when they are no longer providing active service. Employee future benefit expense is recognized in the period in which the employees render services on an accrual basis.

The accrued benefit obligations and the current service costs are calculated using the projected benefit method prorated on service and based on assumptions that reflect management's best estimate. The current service cost for a period is equal to the actuarial present value of benefits attributed to employees' services rendered in the period. Past service costs arising from plan amendments are amortized on a straight-line basis over the average remaining service period of employees active at the date of amendment. The excess of the net actuarial gains or losses over 10% of the accrued benefit obligation is amortized into expense over the average remaining service period of active employees to full eligibility. The effects of a curtailment gain or loss are recognized in income in the year of the event giving rise to the curtailment. The effects of a settlement gain or loss are recognized in the period in which a settlement occurs.

n) Asset retirement obligations

The Corporation recognizes a liability for the future removal and handling costs for contamination in distribution equipment in service and in storage and for the future environmental remediation of certain properties. Initially, the liability is measured at present value and the amount of the liability is added to the carrying amount of the related asset. In subsequent periods, the asset is depreciated and the liability is adjusted quarterly for the discount applied upon initial recognition of the liability ["accretion expense"] and for changes in the underlying assumptions. The liability is recognized when the asset retirement obligation ["ARO"] is incurred and when the fair value is determined.

o) Customers' advance deposits

Customers' advance deposits are cash collections from customers to guarantee the payment of energy bills. The customers' advance deposits liability includes interest credited to the customers' deposit accounts, with the debit charged to net financing charges. Deposits expected to be refunded to customers within the next fiscal year are classified as a current liability.

p) Payments in lieu of corporate taxes

The Corporation is exempt from tax under the *Income Tax Act* (Canada) ["ITA"] if not less than 90% of the capital of the Corporation is owned by the City and not more than 10% of the income of the Corporation is derived from activities carried on outside the municipal geographical boundaries of the City. In addition, the Corporation's subsidiaries are also exempt from tax under the ITA provided that all of their capital is owned by the Corporation and not more than 10% of their respective income is from activities carried on outside the municipal geographical boundaries of the City. A corporation exempt from tax under the ITA is also exempt from tax under the *Taxation Act, 2007* (Ontario) ["TA"] and the *Corporations Tax Act* (Ontario) ["CTA"].

The Corporation and each of its subsidiaries are Municipal Electricity Utilities ["MEUs"] for purposes of the PILs regime contained in the Electricity Act. The Electricity Act provides that a MEU that is exempt from tax under the ITA, the CTA and the TA is required to make, for each taxation year, a PILs payment to the Ontario Electricity

Financial Corporation in an amount equal to the tax that it would be liable to pay under the ITA and the TA (for years ending after 2008) or the CTA (for years ending prior to 2009) if it were not exempt from tax. The PILs regime came into effect on October 1, 2001, at which time the Corporation and each of its subsidiaries were deemed to have commenced a new taxation year for purposes of determining their respective liabilities for PILs payments.

The Corporation uses the liability method of accounting for income taxes. Under the liability method, future income tax assets and liabilities are determined based on differences between the accounting and tax bases of assets and liabilities and measured using the substantively enacted tax rates and laws that will be in effect when the differences are expected to reverse. The effect on future income tax assets and liabilities of a change in tax rates is included in income in the period the change is substantively enacted. Future income tax assets are evaluated and if realization is not considered more likely than not, a valuation allowance is established. In accordance with the Canadian Institute of Chartered Accountants ["CICA"] Handbook Section 3465 – "Income Taxes", LDC recognizes future income taxes associated with its rate-regulated operations and records an offsetting regulatory asset or liability for the future income taxes that are expected to be recovered or refunded through future regulated prices charged to customers.

q) Use of estimates

The preparation of the Corporation's consolidated financial statements in accordance with Canadian GAAP requires management to make estimates and assumptions which affect the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities at the date of the consolidated financial statements and the reported amounts of revenues and expenses for the year. The estimates are based on historical experience, current conditions and various other assumptions that are believed to be reasonable under the circumstances, the results of which form the basis for making judgments about the carrying values of assets and liabilities as well as identifying and assessing the accounting treatment with respect to commitments and contingencies. Significant areas requiring the use of management estimates relate to unbilled revenue, regulatory assets and liabilities, environmental liabilities and AROs, employee future benefits, and revenue recognition. Actual results could differ from those estimates, including changes as a result of future decisions made by the OEB, the Ministry of Energy, or the Ministry of Finance of Ontario ["Ministry of Finance"].

r) Future Accounting Pronouncements

Adoption of New Accounting Standards

Publicly accountable enterprises in Canada were required to adopt International Financial Reporting Standards ["IFRS"] in place of Canadian GAAP for interim and annual reporting purposes for fiscal years beginning on or after January 1, 2011. On September 10, 2010, the Accounting Standards Board granted an optional one-year deferral for IFRS adoption for entities subject to rate regulation due to the uncertainty created by the International Accounting Standards Board ["IASB"] in regard to RRA. To date, the IASB has not approved any temporary exemption or finalized a RRA standard under IFRS. The Corporation elected to take the optional one-year deferral of its adoption of IFRS; therefore, it continues to prepare its consolidated financial statements in accordance with Canadian GAAP accounting standards in Part V of the CICA Handbook in 2011.

The Corporation's IFRS conversion project was proceeding as planned to meet the January 1, 2011 conversion date. In the absence of a definitive plan to consider the issuance of a RRA standard by the IASB, the Corporation decided to evaluate the option of adopting United States ["US"] GAAP effective January 1, 2012 as an alternative to IFRS. The Corporation's current application of Canadian GAAP for RRA is generally consistent with US GAAP. Under US GAAP, the Corporation's financial reporting is expected to be more comparable with its current Canadian

[all tabular amounts in thousands of dollars]

GAAP results than it would be under IFRS and is expected to facilitate comparability with other large North American utilities.

On July 8, 2011, the Corporation filed an application with the applicable Canadian securities regulatory authorities pursuant to section 5.1 of National Instrument 52-107 "Acceptable Accounting Principles and Auditing Standards", to permit the Corporation to prepare its consolidated financial statements in accordance with US GAAP without qualifying as a US Securities and Exchange Commission issuer.

On July 21, 2011, the applicable Canadian securities regulatory authorities issued a decision which gave the Corporation the option to prepare its consolidated financial statements in accordance with US GAAP for its fiscal years beginning on or after January 1, 2012 but before January 1, 2015. The decision is similar to that obtained by other Canadian rate-regulated utilities.

On August 19, 2011, LDC filed a letter with the OEB stating its intention to adopt US GAAP as the basis for the calculation of electricity distribution rates starting in 2012 in accordance with the guidelines provided by the OEB. In the OEB guidelines, the OEB indicated to Ontario utilities that it would permit the use of US GAAP for the calculation of electricity distribution rates if such utilities receive approval from the Ontario Securities Commission and if it benefits electricity distribution consumers.

On August 26, 2011, the board of directors of the Corporation approved the adoption of US GAAP for financial reporting purposes for the year beginning on January 1, 2012. Accordingly, the Corporation plans to commence reporting under US GAAP in its first quarterly consolidated financial statements in 2012. As a result of this decision, the Corporation's IFRS conversion project efforts have been reduced. However, the work has been managed in such a way that it can effectively be restarted when a future transition to IFRS is required.

The Corporation's interim consolidated financial statements for the first quarter of 2012 are expected to be prepared in accordance with US GAAP and applied retrospectively to the Corporation's opening US GAAP consolidated balance sheet as at January 1, 2011. Based on the results of the detailed assessment of the differences between US GAAP and Canadian GAAP as it applies to its business, the Corporation does not believe that the adoption of US GAAP will have a material impact on its consolidated financial statements in the future.

4. INVENTORIES

Inventories consist of the following:

	2011 $	2010 $
Consumables, tools and other maintenance items	**1,745**	2,077
Fuses	**1,625**	1,731
Drums and reels	**938**	1,092
Other	**2,583**	2,601
	6,891	7,501

For the year ended December 31, 2011, the Corporation recognized operating expenses of $6,567,000 related to inventory used to service electrical distribution assets [2010 - $4,727,000].

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
[all tabular amounts in thousands of dollars]

December 31, 2011

5. PROPERTY, PLANT AND EQUIPMENT, NET

Property, plant and equipment consist of the following:

	2011			2010		
	Cost $	Accumulated depreciation $	Net book value $	Cost $	Accumulated depreciation $	Net book value $
Land	**16,761**	**—**	**16,761**	9,560	—	9,560
Distribution lines	**2,850,401**	**1,441,333**	**1,409,068**	2,608,555	1,384,876	1,223,679
Transformers	**652,102**	**360,398**	**291,704**	609,702	341,706	267,996
Stations	**277,905**	**137,246**	**140,659**	259,337	128,254	131,083
Meters	**238,459**	**124,117**	**114,342**	214,859	114,808	100,051
Buildings	**154,932**	**62,403**	**92,529**	151,543	55,609	95,934
Rolling stock	**78,016**	**43,154**	**34,862**	73,749	43,208	30,541
Other capital assets	**68,802**	**44,108**	**24,694**	59,049	35,462	23,587
Assets under capital lease	**14,269**	**1,251**	**13,018**	886	351	535
Equipment and tools	**44,208**	**31,785**	**12,423**	41,604	29,732	11,872
Computer hardware	**44,625**	**35,602**	**9,023**	40,634	31,228	9,406
Communications	**31,537**	**23,912**	**7,625**	26,818	21,013	5,805
Construction in progress	**232,789**	**—**	**232,789**	218,728	—	218,728
	4,704,806	**2,305,309**	**2,399,497**	4,315,024	2,186,247	2,128,777

For the year ended December 31, 2011, AFUDC in the amount of $3,786,000 [2010 - $1,850,000] was capitalized to property, plant and equipment and credited to net financing charges.

As at December 31, 2011, the net book value of stranded meters related to the deployment of smart meters amounting to $20,366,000 [December 31, 2010 - $23,120,000] was included in property, plant and equipment. In the absence of rate regulation, property, plant and equipment would have been $20,366,000 lower as at December 31, 2011 [December 31, 2010 - $23,120,000 lower].

For the year ended December 31, 2011, the Corporation recognized a gain of $3,885,000 [2010 - $3,767,000] on disposals of surplus properties, of which $1,375,000 [2010 - $2,750,000] relates to surplus properties for which the OEB reduced electricity distribution rates in 2010. LDC began recognizing the actual gain realized on the sale of these properties over a one-year period from May 1, 2010 to mirror the actual timing of the reduction in 2010 electricity distribution rates.

For the year ended December 31, 2011, the Corporation recorded depreciation expense of $125,210,000 [2010 - $153,189,000] of which $1,177,000 [2010 - $204,000] related to assets under capital lease.

[all tabular amounts in thousands of dollars]

6. INTANGIBLE ASSETS, NET

Intangible assets consist of the following:

	2011			2010		
	Cost $	Accumulated amortization $	Net book value $	Cost $	Accumulated amortization $	Net book value $
Computer software	**222,598**	**154,186**	**68,412**	172,709	129,301	43,408
Contributions	**14,059**	**1,440**	**12,619**	2,043	524	1,519
Software in development	**3,582**	—	**3,582**	39,191	—	39,191
Contributions for work in progress	**28,369**	—	**28,369**	1,878	—	1,878
	268,608	**155,626**	**112,982**	215,821	129,825	85,996

For the year ended December 31, 2011, the Corporation acquired $52,805,000 of intangible assets [2010 - $28,387,000]. All intangible assets are subject to amortization when they become available for use. Software in development and contributions for work in progress relate to assets not currently available for use and therefore are not amortized.

For the year ended December 31, 2011, $49,907,000 of software in development were transferred to computer software [2010 - $29,266,000].

For the year ended December 31, 2011, AFUDC in the amount of $1,419,000 [2010 - $1,658,000] was capitalized to intangible assets and credited to net financing charges.

For the year ended December 31, 2011, the Corporation recorded amortization expense on intangible assets of $25,812,000 [2010 - $16,219,000].

7. REGULATORY ASSETS AND LIABILITIES

Regulatory assets consist of the following:

	2011 $	2010 $
Smart meters	**61,422**	67,719
Late payment penalties settlement	—	7,750
IFRS conversion project	—	6,089
Settlement variances	**14,119**	—
Special purpose charge variance	**572**	3,555
Other	**1,209**	—
	77,322	85,113

[all tabular amounts in thousands of dollars]

Regulatory liabilities consist of the following:

	2011 $	2010 $
Future income taxes	**200,436**	224,570
Regulatory assets recovery account	**6,361**	40,275
PILs variances	**2,365**	5,675
Settlement variances	**—**	2,277
Other	**1,118**	909
	210,280	273,706

For the year ended December 31, 2011, LDC disposed of approved net regulatory liabilities amounting to $34,528,000 through permitted distribution rate adjustments [2010 - $23,003,000].

The regulatory assets and liabilities of the Corporation are as follows:

a) Smart Meters

The smart meters regulatory asset account relates to Ontario's decision to install smart meters throughout Ontario. LDC substantially completed its smart meter project as at December 31, 2010. In connection with this initiative, the OEB ordered LDC to record all expenditures and related revenues from 2008 to 2010 to a regulatory asset account and allowed LDC to keep the net book value of the stranded meters in property, plant and equipment. Starting on January 1, 2011, LDC began recording smart meter costs in property, plant and equipment and intangible assets as a regular distribution activity as directed by the OEB. LDC expects to apply to the OEB to transfer the 2008 to 2010 smart meter costs from regulatory assets to property, plant and equipment and intangible assets, as well as to transfer the net book value of the stranded meters from property, plant and equipment to regulatory assets in 2012.

The Corporation incurred smart meter capital expenditures amounting to $nil for the year ended December 31, 2011 [2010 - $19,799,000]. As at December 31, 2011, smart meter capital expenditures, net of accumulated depreciation, totalling $59,227,000 were recorded to regulatory assets [December 31, 2010 - $65,588,000]. These expenditures would otherwise have been recorded as property, plant and equipment and intangible assets under Canadian GAAP for unregulated businesses. In the absence of rate regulation, property, plant and equipment and intangible assets would have been $54,825,000 and $4,402,000 higher, respectively, as at December 31, 2011 [December 31, 2010 - $59,416,000 and $6,172,000 higher, respectively].

For the year ended December 31, 2011, deferred smart meter operating expenses were reduced by $490,000 which would have reduced expenses under Canadian GAAP for unregulated businesses [2010 – were increased by $3,109,000]. For the year ended December 31, 2011, smart meter depreciation expense of $6,361,000 [2010 - $5,357,000] were deferred which would have been expensed under Canadian GAAP for unregulated businesses. In the absence of rate regulation, for the year ended December 31, 2011, operating expenses would have been $490,000 lower [2010 - $3,109,000 higher], and depreciation expense would have been $6,361,000 higher [2010 - $5,357,000 higher].

For the year ended December 31, 2011, smart meter customer revenues of $5,866,000 were deferred [2010 - $5,774,000]. In the absence of rate regulation, for the year ended December 31, 2011, revenue would have been $5,866,000 higher [2010 - $5,774,000 higher].

b) Late Payment Penalties Settlement

The late payment penalties settlement regulatory asset account was related to the settlement costs associated with the late payment charges class action. All of the MEUs involved in the settlement, including LDC, requested an order from the OEB allowing for the future recovery from customers of all costs related to the settlement. On February 22, 2011, the OEB approved the recovery of the costs of $7,526,000. The recovery is occurring over a 21-month period which commenced on August 1, 2011. Accordingly, the balance approved for recovery was transferred to the Regulatory Assets Recovery Account ["RARA"].

c) IFRS Conversion Project

This regulatory asset account included the incremental costs incurred by LDC for its initially planned conversion to IFRS. On July 7, 2011, the OEB reduced the allowable recoverable costs from $6,134,000 to $3,050,000 as it appeared that a portion of the costs claimed for recovery by LDC were included in prior period electricity distribution rates. In connection with this decision from the OEB, the Corporation revised its estimate for IFRS conversion costs recovery, resulting in an increase in operating expenses of $3,017,000 in the second quarter of 2011. The remaining regulatory asset balance of $3,050,000, which included carrying charges, was transferred to the RARA and is being recovered over a nine-month period which commenced on August 1, 2011. Under Canadian GAAP for unregulated businesses, these costs would have been recorded to operating expenses. In the absence of rate regulation, for the year ended December 31, 2011, operating expenses would have been $3,017,000 lower [2010 - $3,108,000 higher].

d) Settlement Variances

This account is comprised of the variances between amounts charged by LDC to customers, based on regulated rates, and the corresponding cost of non-competitive electricity service incurred by LDC. The settlement variances relate primarily to service charges, non-competitive electricity charges, imported power charges and the global adjustment. Accordingly, LDC has deferred the variances between the costs incurred and the related recoveries in accordance with the criteria set out in the accounting principles prescribed by the OEB in the AP Handbook.

The balance for settlement variances continues to be calculated and attract carrying charges in accordance with the OEB's direction. For the year ended December 31, 2011, settlement variances of $34,938,000 were disposed through rate adjustments [2010 - $20,016,000].

e) Special Purpose Charge Variance

On April 9, 2010, the OEB informed electricity distributors of a Special Purpose Charge ["SPC"] assessment under Section 26.1 of the OEB Act, for the Ministry of Energy and Infrastructure conservation and renewable energy program costs. The OEB assessed LDC the amount of $9,698,000 for its apportioned share of the total provincial amount of the SPC of $53,695,000 in accordance with the rules set out in Ontario Regulation 66/10 [the "SPC Regulation"]. In accordance with Section 9 of the SPC Regulation, LDC was allowed to recover this balance. The recovery was completed as at April 30, 2011.

As at December 31, 2011, the balance in the account consists of LDC's assessment of $9,698,000 less the recoveries received from customers. In the absence of rate regulation, revenue for the year ended December 31, 2011, would have been $3,050,000 higher [2010 - $6,123,000 higher] and operating expenses for the year ended December 31, 2011 would have $nil impact [2010 - $9,698,000 higher].

f) Future Income Taxes

This regulatory liability account relates to the expected future electricity distribution rate reduction for customers arising from timing differences in the recognition of future tax assets *[note 3[p]]*.

As at December 31, 2011, LDC recorded a future income tax asset and a corresponding regulatory liability of $200,436,000 [December 31, 2010 - $224,570,000] with respect to its rate-regulated activities. The future income tax asset and the corresponding regulatory liability as at December 31, 2010, have been recast, to reflect an adjustment of $30,247,000 resulting from a change in methodology used to determine the timing differences between the tax value and book value of the assets for accounting purposes.

g) Regulatory Assets Recovery Account

The RARA consists of balances of regulatory assets or regulatory liabilities approved for disposition by the OEB through rate riders. The RARA is subject to carrying charges following the OEB prescribed methodology and related rates.

On April 16, 2009, the OEB approved the disposition of regulatory liabilities of $7,582,000, for amounts arising from the extended effectiveness of certain rate riders into the 2008 rate year, over a one-year period commencing on May 1, 2009 and ending on April 30, 2010.

On April 9, 2010, the OEB approved the disposition of net regulatory liabilities of $68,140,000, consisting of credit balances for settlement variances and PILs variances of $58,225,000 and $11,900,000, respectively, and intangible assets debit balance of $1,985,000, over a two-year period commencing on May 1, 2010 and ending on April 30, 2012.

On October 29, 2010, the OEB approved the disposition of regulatory assets of $5,296,000, for amounts in connection with the contact voltage remediation activities, for the period commencing on November 1, 2010 and ending on April 30, 2012 *[note 2[d]]*.

On February 22, 2011, the OEB approved the disposition of the Late Payment Penalties Settlement regulatory asset of $7,526,000, over a 21-month period commencing on August 1, 2011 and ending on April 30, 2013.

On July 7, 2011, the OEB approved the disposition of net regulatory liabilities of $8,572,000, consisting of credit balances for settlement variances, PILs variances and 2008 RARA residual of $7,460,000, $3,373,000, and $789,000, respectively, and an IFRS cost debit balance of $3,050,000, over a nine-month period commencing on August 1, 2011 and ending on April 30, 2012.

h) PILs Variances

The PILs variances regulatory liability account relates to the differences that have resulted from a legislative or regulatory change to the tax rates or rules assumed in the rate adjustment model. As at December 31, 2011, the balance in this account consisted of an over-recovery from customers of $2,365,000 [December 31, 2010 - $5,675,000].

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

[all tabular amounts in thousands of dollars]

December 31, 2011

8. OTHER ASSETS

Other assets consist of the following:

	2011 $	2010 $
Prepaid leases	**7,279**	7,368
Other	**52**	150
	7,331	7,518

9. CREDIT FACILITIES

On May 3, 2011, the Corporation extended its revolving credit facility ["Revolving Credit Facility"] for an additional term, expiring on May 3, 2013. Under the terms of the Revolving Credit Facility, the Corporation may borrow up to $400,000,000, of which:

[i] $400,000,000 less the amount utilized under [ii] is available for working capital and LDC capital expenditure purposes in the form of prime rate loans in Canadian dollars and Bankers' Acceptance ["BAs"]; and

[ii] up to $140,000,000 is available in the form of letters of credit to support the prudential requirements of LDC and TH Energy and general credit requirements of the Corporation and its subsidiaries.

The fee payable for BAs and letters of credit is based on a margin determined by reference to the Corporation's credit rating. The Revolving Credit Facility contains a negative pledge, customary covenants and events of default.

As at December 31, 2011, no amounts had been drawn under the Corporation's Revolving Credit Facility [December 31, 2010 - $nil]. As at December 31, 2011, no amounts had been drawn for working capital purposes [December 31, 2010 - $nil].

Additionally, the Corporation is a party to a bilateral facility for $50,000,000 for the purpose of issuing letters of credit mainly to support LDC's prudential requirements with the IESO. As at December 31, 2011, $45,077,000 had been drawn on the bilateral facility [December 31, 2010 - $46,077,000].

10. CURRENT PORTION OF OTHER LIABILITIES

Current portion of other liabilities consist of the following:

	2011 $	2010 $
Customers' advance deposits	**20,108**	18,790
Obligations under capital lease *[note 21]*	**1,871**	182
Other	**311**	761
	22,290	19,733

[all tabular amounts in thousands of dollars]

11. DEBENTURES

Debentures consist of the following:

	2011 $	2010 $
Senior unsecured debentures		
Series 1 – 6.11% due May 7, 2013	**224,298**	223,838
Series 2 – 5.15% due November 14, 2017	**248,941**	248,793
Series 3 – 4.49% due November 12, 2019	**248,682**	248,546
Series 4 – 6.11% due December 30, 2011	**—**	245,057
Series 5 – 6.11% due May 6, 2013	**245,057**	245,057
Series 6 – 5.54% due May 21, 2040	**198,566**	198,546
Series 7 – 3.54% due November 18, 2021	**297,970**	—
Total debentures	**1,463,514**	1,409,837
Less: Current portion of debentures	**—**	245,057
Long-term portion of debentures	**1,463,514**	1,164,780

All debentures of the Corporation rank equally.

On May 7, 2003, the Corporation issued $225,000,000 in 10-year senior unsecured debentures [“Series 1”]. The Series 1 debentures bear interest at the rate of 6.11% per annum, payable semi-annually in arrears in equal instalments on May 7 and November 7 of each year. The Series 1 debentures mature on May 7, 2013.

On November 14, 2007, the Corporation issued $250,000,000 in 10-year senior unsecured debentures [“Series 2”]. The Series 2 debentures bear interest at the rate of 5.15% per annum, payable semi-annually in arrears in equal instalments on May 14 and November 14 of each year. The Series 2 debentures mature on November 14, 2017.

On November 12, 2009, the Corporation issued $250,000,000 in 10-year senior unsecured debentures [“Series 3”]. The Series 3 debentures bear interest at the rate of 4.49% per annum, payable semi-annually in arrears in equal instalments on May 12 and November 12 of each year. The Series 3 debentures mature on November 12, 2019.

On April 1, 2010, the Corporation issued $245,057,000 senior unsecured debentures [“Series 4”]. The Series 4 debentures bear interest at the rate of 6.11% per annum, payable semi-annually in arrears in equal instalments on June 30 and December 30 of each year and on the maturity date. The Series 4 debentures matured on December 30, 2011.

On April 1, 2010, the Corporation issued $245,057,000 senior unsecured debentures [“Series 5”]. The Series 5 debentures bear interest at the rate of 6.11% per annum, payable semi-annually in arrears in equal instalments on May 6 and November 6 of each year and on the maturity date. The Series 5 debentures mature on May 6, 2013.

On May 20, 2010, the Corporation issued $200,000,000 in 30-year senior unsecured debentures [“Series 6”]. The Series 6 debentures bear interest at the rate of 5.54% per annum, payable semi-annually in arrears in equal instalments on May 21 and November 21 of each year. The Series 6 debentures mature on May 21, 2040.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
[all tabular amounts in thousands of dollars]

December 31, 2011

On November 18, 2011, the Corporation issued $300,000,000 in 10-year senior unsecured debentures [“Series 7”]. The Series 7 debentures bear interest at the rate of 3.54% per annum, payable semi-annually in arrears in equal instalments on May 18 and November 18 of each year. The Series 7 debentures mature on November 18, 2021.

The Corporation may redeem some or all of the debentures at any time prior to maturity at a price equal to the greater of the Canada Yield Price (determined in accordance with the terms of the debentures) and par, plus accrued and unpaid interest up to but excluding the date fixed for redemption. Also, the Corporation may, at any time and from time to time, purchase debentures for cancellation, in the open market, by tender or by private contract, at any price. The debentures contain certain covenants which, subject to certain exceptions, restrict the ability of the Corporation and LDC to create security interests, incur additional indebtedness or dispose of all or substantially all of their assets.

12. EMPLOYEE FUTURE BENEFITS

Pension

For the year ended December 31, 2011, the Corporation’s OMERS current service pension costs were $14,115,000 [2010 - $12,024,000]. For the year ended December 31, 2011, OMERS contribution rates were 7.4% up to the year’s maximum pensionable earnings [“YMPE”] and 10.7% over YMPE for normal retirement age [“NRA”] of 65 [December 31, 2010 - 6.4% up to YMPE and 9.7% over YMPE for NRA of 65].

Employee future benefits other than pension

The Corporation has a number of unfunded benefit plans providing retirement and post-employment benefits (excluding pension) to most of its employees. The Corporation pays certain medical, dental and life insurance benefits under unfunded defined benefit plans on behalf of its retired employees. The Corporation pays accumulated sick leave credits, up to certain established limits based on service, in the event of retirement, termination or death of certain employees.

The Corporation measures its accrued benefits obligation for accounting purposes as at December 31 of each year. The latest actuarial valuation was performed as at January 1, 2010.

a) Accrued benefit obligation

	2011 $	2010 $
Balance, beginning of year	**200,027**	177,144
Experience loss at beginning of year	—	8,013
Current service cost	**3,908**	3,485
Interest cost	**11,507**	11,102
Benefits paid	**(7,495)**	(7,197)
Actuarial losses	**36,379**	7,480
Balance, end of year	**244,326**	200,027

[all tabular amounts in thousands of dollars]

b) Reconciliation of the accrued benefit obligation to the balance sheet accrued benefit liability

	2011 $	2010 $
Accrued benefit obligation	**244,326**	200,027
Unamortized net actuarial losses	**(63,698)**	(27,952)
Unamortized past service costs	**(1,087)**	(2,178)
Post-employment benefits liability	**179,541**	169,897

c) Components for net periodic defined benefit costs

	2011 $	2010 $
Current service cost	**3,908**	3,485
Interest cost	**11,507**	11,102
Actuarial losses	**36,379**	15,493
Cost incurred in the year	**51,794**	30,080
Differences between costs incurred and costs recognized in the year in respect of:		
Actuarial gains	**(35,746)**	(15,298)
Past service costs	**1,091**	964
	(34,655)	(14,334)
Defined benefit costs recognized	**17,139**	15,746
Capitalized as part of property, plant and equipment	**6,758**	7,388
Charged to operations	**10,381**	8,358

[all tabular amounts in thousands of dollars]

d) Significant assumptions

	2011 %	2010 %
Accrued benefit obligation as at December 31:		
Discount rate	**4.8**	5.8
Rate of compensation increase	**4.0**	4.0
Benefit costs for years ended December 31:		
Discount rate	**5.8**	6.0
Rate of compensation increase	**4.0**	4.0
Assumed health care cost trend rates as at December 31:		
Rate of increase in dental costs	**4.0**	4.0

For December 31, 2011, medical costs are assumed to increase at 7.0% [2010 - 7.5%] graded down by 0.5% [2010 - 0.5%] annual decrements to 5.0% [2010 - 5.0%] in 2016 and thereafter.

e) Sensitivity analysis

Assumed health and dental care cost trend rates have a significant effect on the amounts reported for health and dental care plans. A one-percentage-point change in assumed health and dental care cost trend rates would have the following effects for 2011:

	Increase $	Decrease $
Total of current service and interest cost (at 5.8%)	**2,733**	**(1,880)**
Accrued benefit obligation as at December 31, 2011 (at 4.8%)	**36,933**	**(28,417)**

Assumed interest rates have a significant effect on the amounts reported for the total accrued benefit obligation and expense. A one-percentage-point change in assumed interest rates would have the following effects for 2011:

	Increase $	Decrease $
Accrued benefit obligation as at December 31, 2011	**(33,098)**	**42,923**
Estimated expense for fiscal 2012	**(3,030)**	**3,449**

[all tabular amounts in thousands of dollars]

13. OTHER LIABILITIES

Other long-term liabilities consist of the following:

	2011 $	2010 $
Obligations under capital lease *[note 21]*	**11,301**	369
Other	**—**	265
	11,301	634

For the year ended December 31, 2011, the Corporation acquired property, plant and equipment through capital lease transactions totalling $13,717,000 [2010 - $176,000]. These non-cash transactions have been excluded from the consolidated statements of cash flows.

14. ASSET RETIREMENT OBLIGATIONS

Reconciliation between the opening and closing ARO liability balances is as follows:

	2011 $	2010 $
Balance, beginning of year	**5,005**	7,552
ARO liabilities settled in the year	**(688)**	(2,290)
Accretion expense	**173**	194
Revision in estimated cash flows	**412**	(451)
Balance, end of year	**4,902**	5,005

As at December 31, 2011, the Corporation estimates the undiscounted amount of cash flows required over the next one to 45 years to settle the ARO liabilities is $5,811,000 [December 31, 2010 - $6,560,000]. Discount rates ranging from 1.39% to 6.60% [December 31, 2010 - 1.39% to 6.60%] were used to calculate the carrying value of the ARO liabilities. No assets have been legally restricted for settlement of the liability.

15. CAPITAL DISCLOSURES

The Corporation's main objectives when managing capital are to:

- ensure ongoing access to funding to maintain and refurbish the electricity distribution system of LDC;
- ensure compliance with covenants related to its credit facilities and senior unsecured debentures;
- maintain at least an A- credit rating as required under its shareholder direction; and
- align its capital structure for regulated activities of LDC with the deemed debt to equity structure set by the OEB.

As at December 31, 2011, the Corporation's definition of capital includes long-term debt and obligations under capital lease, including the current portion thereof, and shareholder's equity, and has remained unchanged from

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

[all tabular amounts in thousands of dollars]

December 31, 2011

December 31, 2010. As at December 31, 2011, shareholder's equity amounted to $1,102,248,000 [December 31, 2010 - $1,039,379,000] and long-term debt, including the current portion thereof, amounted to $1,476,686,000 [December 31, 2010 - $1,409,837,000]. The Corporation's capital structure as at December 31, 2011 was 57% debt and 43% equity [December 31, 2010 - 58% debt and 42% equity]. There were no changes in the Corporation's approach to capital management during the year.

As at December 31, 2011, the Corporation is subject to debt agreements that contain various covenants. The Corporation's unsecured debentures limit consolidated funded indebtedness to a maximum of 75% of total consolidated capitalization. As at December 31, 2011, the consolidated funded indebtedness to consolidated capitalization ratio was 57% [December 31, 2010 - 57%].

The Corporation's Revolving Credit Facility limits the debt to capitalization ratio to a maximum of 75%. As at December 31, 2011, the debt to capitalization ratio was 58% [December 31, 2010 - 58%].

The Corporation's long-term debt agreements also include negative covenants such as limitations on funded indebtedness, limitations on designated subsidiary indebtedness, and restrictions on mergers and dispositions of designated subsidiaries. As at December 31, 2011 and as at December 31, 2010, the Corporation was in compliance with all covenants included in its long-term debt agreements and short-term Revolving Credit Facility.

16. FINANCIAL INSTRUMENTS

a) Recognition and measurement

The carrying value and fair value of the Corporation's financial instruments consist of the following:

	2011 $		2010 $	
	Carrying value	**Fair value**	**Carrying value**	**Fair value**
Cash and cash equivalents	**154,256**	**154,256**	330,151	330,151
Investments	**34,002**	**34,002**	—	—
Accounts receivable, net of allowance for doubtful accounts	**183,272**	**183,272**	168,988	168,988
Unbilled revenue	**262,058**	**262,058**	287,893	287,893
Accounts payable and accrued liabilities	**412,412**	**412,412**	373,543	373,543
Obligations under capital lease	**13,172**	**13,172**	505	505
Customers' advance deposits	**56,038**	**56,038**	64,252	64,252
Senior unsecured debentures				
Series 1 – 6.11% due May 7, 2013	**224,298**	**238,359**	223,838	245,310
Series 2 – 5.15% due November 14, 2017	**248,941**	**284,126**	248,793	273,725
Series 3 – 4.49% due November 12, 2019	**248,682**	**275,575**	248,546	259,777
Series 4 – 6.11% due December 30, 2011	**—**	**—**	245,057	255,199
Series 5 – 6.11% due May 6, 2013	**245,057**	**259,578**	245,057	267,177
Series 6 – 5.54% due May 21, 2040	**198,566**	**245,096**	198,546	217,188
Series 7 – 3.54% due November 18, 2021	**297,970**	**306,696**	—	—

[all tabular amounts in thousands of dollars]

b) *Risk Factors*

The following is a discussion of risks and related mitigation strategies that have been identified by the Corporation for financial instruments. This is not an exhaustive list of all risks, nor will the mitigation strategies eliminate all risks listed.

The Corporation's activities provide for a variety of financial risks, particularly credit risk, interest rate risk and liquidity risk.

Credit risk

The Corporation is exposed to credit risk from financial instruments as a result of the risk of counterparties defaulting on their obligations. The Corporation monitors and limits its exposure to credit risk on a continuous basis.

The Corporation's credit risk associated with accounts receivable is primarily related to electricity bill payments from LDC customers. LDC has approximately 709,000 customers, the majority of which are residential. LDC collects security deposits from customers in accordance with direction provided by the OEB. As at December 31, 2011, LDC held security deposits in the amount of $56,038,000 [December 31, 2010 - $64,252,000].

The carrying amount of accounts receivable is reduced through an allowance for doubtful accounts and the amount of the related impairment loss is recognized in the consolidated statements of income. Subsequent recoveries of receivables previously provisioned are credited to the consolidated statements of income.

Credit risk associated with accounts receivable is as follows:

	2011 $	2010 $
Total accounts receivable	**196,259**	180,900
Less: Allowance for doubtful accounts	**(12,987)**	(11,912)
Total accounts receivable, net	**183,272**	168,988
Of which:		
Outstanding for not more than 30 days	**155,274**	147,457
Outstanding for more than 30 days but not more than 120 days	**24,777**	21,635
Outstanding for more than 120 days	**16,208**	11,808
Less: Allowance for doubtful accounts	**(12,987)**	(11,912)
Total accounts receivable, net	**183,272**	168,988

[all tabular amounts in thousands of dollars]

Reconciliation between the opening and closing allowance for doubtful accounts balances is as follows:

	2011 $	2010 $
Balance, beginning of year	**(11,912)**	(12,580)
Provision for doubtful accounts	**(10,272)**	(6,998)
Write-offs	**9,854**	9,273
Recoveries	**(657)**	(1,607)
Balance, end of year	**(12,987)**	(11,912)

Unbilled revenue represents amounts for which the Corporation has a contractual right to receive cash through future billings but are unbilled at period-end. As at December 31, 2011, total unbilled revenue was $262,058,000 [December 31, 2010 - $287,893,000]. Unbilled revenue is considered current.

As at December 31, 2011, there were no significant concentrations of credit risk with respect to any class of financial assets or counterparties. The Corporation's maximum exposure to credit risk is equal to the carrying value of its financial assets.

Interest rate risk

The Corporation is exposed to interest rate risk through holding certain financial instruments, and short-term borrowings under the Corporation's Revolving Credit Facility *[note 9]* which may expose the Corporation to fluctuations in short-term interest rates (borrowings in the form of prime rate loans in Canadian dollars and BAs and letters of credit). The Corporation attempts to minimize interest rate risk by issuing long-term fixed rate debt, and by extending or shortening the term of its short-term money market investments by assessing the monetary policy stance of the Bank of Canada, while ensuring that all payment obligations are met on an ongoing basis.

Cash balances, which are not required to meet day-to-day obligations of the Corporation, are either held in bank accounts or invested in Canadian money market instruments, exposing the Corporation to fluctuations in short-term interest rates. These fluctuations could impact the level of interest income earned by the Corporation.

LDC is exposed to fluctuations in interest rates as its regulated rate of return is derived using a formulaic approach, which is based in part on a forecast of long-term Government of Canada bond yields and A-rated Canadian utility bond spreads. LDC estimates that a 1% (100 basis point) reduction in long-term Government of Canada bond yields, used in determining its regulated rate of return would reduce LDC's annual net income, as at December 31, 2011, by approximately $4,600,000.

The Corporation is also exposed to fluctuations in interest rates for the valuation of its post-employment benefit obligations *[note 12[e]]*.

Liquidity risk

The Corporation is exposed to liquidity risk related to commitments associated with financial instruments. The Corporation monitors and manages its liquidity risk to ensure access to sufficient funds to meet operational and investing requirements. The Corporation's objective is to ensure that sufficient liquidity is on hand to meet obligations as they fall due while minimizing net financing charges. The Corporation has access to credit facilities and monitors cash balances daily to ensure that sufficient levels of liquidity are on hand to meet financial commitments as they come due. Liquidity risks associated with financial commitments are as follows:

[all tabular amounts in thousands of dollars]

December 31, 2011	Due within 1 year $	Due between 1 year and 5 years $	Due after 5 years $
Financial liabilities			
Accounts payable and accrued liabilities	**412,412**	**—**	**—**
Obligations under capital lease	**1,871**	**8,042**	**3,259**
Senior unsecured debentures			
Series 1 – 6.11% due May 7, 2013	**—**	**225,000**	**—**
Series 2 – 5.15% due November 14, 2017	**—**	**—**	**250,000**
Series 3 – 4.49% due November 12, 2019	**—**	**—**	**250,000**
Series 5 – 6.11% due May 6, 2013	**—**	**245,057**	**—**
Series 6 – 5.54% due May 21, 2040	**—**	**—**	**200,000**
Series 7 – 3.54% due November 18, 2021	**—**	**—**	**300,000**
Interest payments on debentures	**74,905**	**197,560**	**359,293**
	489,188	**675,659**	**1,362,552**

Hedging and Derivative risk

As at December 31, 2011 and December 31, 2010, the Corporation had not entered into hedging and derivative financial instruments.

Foreign exchange risk

As at December 31, 2011, the Corporation had limited exposure to the changing values of foreign currencies. While the Corporation purchases goods and services which are payable in US dollars, and purchases US currency to meet the related payables commitments when required, the impact of these transactions is not material to the consolidated financial statements.

17. FINANCIAL GUARANTEES

The City has authorized the Corporation to provide financial assistance to its subsidiaries, and LDC to provide financial assistance to other subsidiaries of the Corporation, in the form of letters of credit and guarantees, for the purpose of enabling them to carry on their businesses up to an aggregate amount of $500,000,000.

[all tabular amounts in thousands of dollars]

18. PAYMENTS IN LIEU OF CORPORATE TAXES

The provision for PILs differs from the amount that would have been recorded using the combined Canadian federal and Ontario statutory income tax rate. Reconciliation between the statutory and effective tax rates is set out below:

Consolidated Statements of Income

	2011 $	2010 $
Rate reconciliation		
Income before PILs	**104,750**	91,705
Consolidated Statutory Canadian federal and provincial income tax rate	**28.25%**	31.00%
Expected provision for PILs	**29,592**	28,429
Temporary differences not benefited	**(16,032)**	(1,303)
Other	**(4,742)**	(1,546)
Provision for PILs	**8,818**	25,580
Effective tax rate	**8.42%**	27.89%
Components of provision for PILs		
Current tax provision	**9,419**	24,709
Future income tax provision related to the origination and reversal of temporary differences	**(601)**	871
Provision for PILs	**8,818**	25,580

Consolidated Balance Sheets

Significant components of the Corporation's future income tax assets and liabilities are as follows:

	2011 $	2010 $
Property, plant and equipment and intangible assets	**110,161**	131,232
Regulatory adjustments	**50,109**	56,142
Post-employment benefits liability	**44,885**	42,474
Other taxable temporary differences	**6,482**	6,583
Capital loss carryforwards	**5,147**	4,840
Non-capital loss carryforwards	**503**	509
Valuation allowance	**(14,920)**	(15,880)
Future income tax assets	**202,367**	225,900

As at December 31, 2011, the Corporation accumulated non-capital losses for PILs purposes of approximately $2,011,000 [December 31, 2010 - $2,037,000], which are available to reduce taxable income in future years. As at December 31, 2011, the Corporation also accumulated taxable capital losses of $19,698,000 [December 31, 2010 -

[all tabular amounts in thousands of dollars]

$19,359,000] which are available to offset capital gains in future years. If not utilized, $500,000 of non-capital losses will expire in 2014 and 2015, and $1,511,000 of non-capital losses will expire in or after 2026.

19. SHARE CAPITAL

Share capital consists of the following:

	2011 $	2010 $
Authorized		
The authorized share capital of the Corporation consists of an unlimited number of common shares		
Issued and outstanding		
1,000 common shares	**567,817**	567,817

Dividends

The shareholder direction adopted by the City with respect to the Corporation provides that the board of directors of the Corporation will use its best efforts to ensure that the Corporation meets certain financial performance standards, including those relating to the credit rating and dividends.

Subject to applicable law, the shareholder direction provides that the Corporation will pay dividends to the City each year amounting to the greater of $25,000,000 or 50% of the Corporation's consolidated net income for the year. The dividends are not cumulative and are payable as follows:

[i] $6,000,000 on the last day of each of the first three fiscal quarters during the year;

[ii] $7,000,000 on the last day of the fiscal year; and

[iii] the amount, if any, by which 50% of the Corporation's annual consolidated net income for the year exceeds $25,000,000, within ten days after the board of directors of the Corporation approved the Corporation's audited consolidated financial statements for the year.

During 2011, the board of directors of the Corporation declared and paid dividends totalling $33,063,000 [2010 - $25,000,000] to the City.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
[all tabular amounts in thousands of dollars]

December 31, 2011

20. RELATED PARTIES

For the Corporation, transactions with related parties include transactions with the City. All transactions with the City are conducted at prevailing market prices and normal trade terms.

Transactions with Related Parties Summary	2011 $	2010 $
Revenues	**147,469**	147,399
Operating expenses and capital expenditures	**30,582**	14,068
Net financing charges	**—**	7,487
Dividends	**33,063**	25,000

Transactions with Related Parties Summary	2011 $	2010 $
Accounts receivable, net of allowance for doubtful accounts	**8,412**	6,711
Unbilled revenue	**8,692**	9,830
Other assets	**7,279**	7,368
Accounts payable and accrued liabilities	**25,085**	12,164
Customers' advance deposits	**8,714**	10,953

Revenues represent amounts charged to the City primarily for electricity and street lighting services. Operating expenses and capital expenditures represent amounts charged by the City for purchased road cut repairs, property taxes and other services. Net financing charges represent interest paid to the City on the promissory note which was monetized on April 1, 2010. Dividends represent dividends paid to the City *[note 19]*.

Accounts receivable, net of allowance for doubtful accounts represent receivables from the City primarily for relocation services, sale of electricity and street lighting services. Unbilled revenue represents receivables from the City related to the provision of electricity not yet billed. Other assets represent amounts for prepaid land leases from the City. Accounts payable and accrued liabilities represent amounts payable to the City relating to road cut repairs and other services, as well as funds received from the City for the construction of electricity distribution assets. Customers' advance deposits represent funds received from the City for future expansion projects.

21. COMMITMENTS

Operating lease obligations and future commitments

As at December 31, 2011, the future minimum annual lease payments under property operating leases and future commitments with remaining terms from one to five years and thereafter were as follows:

[all tabular amounts in thousands of dollars]

December 31, 2011

	$
2012	**27,715**
2013	**23,442**
2014	**7,492**
2015	**6,487**
2016	**6,308**
Thereafter	**4,755**
Total amount of future minimum payments	**76,199**

During the first quarter of 2011, LDC entered into an agreement with Hydro One Networks Inc. to reinforce the 115 kilovolt transmission system between Leaside Transformer Station ["TS"] and Bridgman TS under the Toronto Midtown Transmission Reinforcement Project, which terminates on the 25th anniversary of the in service date. LDC is expected to pay the estimated capital contributions and work chargeable by making progress payments based on various payment milestone dates, with $17,600,000 and $15,278,000 payable in 2012 and 2013, respectively, and any difference from the estimated costs to be settled at a later date. These commitments have been reflected in the table above.

Capital lease obligations

As at December 31, 2011, the future minimum annual lease payments under capital leases with remaining lease terms from one to five years and thereafter were as follows:

	$
2012	**2,454**
2013	**2,445**
2014	**2,404**
2015	**2,327**
2016	**2,267**
Thereafter	**3,380**
Total amount of future minimum payments	**15,277**
Less interest and executory costs	**2,105**
	13,172
Current portion *[note 10]*	**1,871**
Long-term portion *[note 13]*	**11,301**

Included in the capital lease obligations is an equipment lease entered into by the Corporation in the third quarter of 2011 which expires in June 2018 and bears interest at a rate of 4.7%.

22. CONTINGENCIES

a) Legal Proceedings

In the ordinary course of business, the Corporation is subject to various litigation and claims with customers, suppliers, former employees and other parties. On an ongoing basis, the Corporation assesses the likelihood of any adverse judgments or outcomes as well as potential ranges of probable costs and losses. A determination of the provision required, if any, for these contingencies is made after analysis of each individual issue. The provision may change in the future due to new developments in each matter or changes in approach, such as a change in settlement strategy. The Corporation and its subsidiaries are subject to various legal actions that arise in the normal course of business and if damages were awarded under these actions, the Corporation and its subsidiaries would make a claim under their liability insurance which the Corporation believes would cover any damages which may become payable by the Corporation and its subsidiaries in connection with these actions.

Christian Helm Class Action

On December 6, 2010, a statement of claim in a proposed class action was issued against LDC. The claim seeks general and special damages in the amount of $100,000,000 for disgorgement of unjust gains allegedly resulting from the receipt of interest on overdue accounts at a rate exceeding 5% per annum in contravention of the *Interest Act* (Canada) ["Interest Act"]. A statement of defence has been filed. Prior to any certification of the action as a class proceeding, cross summary judgment motions were heard in June 2011 to determine whether the Interest Act has been breached *[note 25[c]]*.

2 Secord Avenue

An action was commenced against LDC in September 2008 in the Ontario Superior Court of Justice under the *Class Proceedings Act, 1992* (Ontario) ["Class Proceedings Act"] seeking damages in the amount of $30,000,000 as compensation for damages allegedly suffered as a result of a fire and explosion in an underground vault at 2 Secord Avenue on July 20, 2008. This action is at a preliminary stage. The statement of claim has been served on LDC, a statement of defence and third party claim have been served by LDC and a third party defence and counterclaim against LDC seeking damages in the amount of $51,000,000 have been filed. A certification order has been issued. Affidavits of documents have been produced by LDC to the other parties and examinations for discovery have commenced and are continuing. Given the preliminary status of this action, it is not possible to reasonably quantify the effect, if any, of this action on the financial performance of the Corporation. If damages were awarded, LDC would make a claim under its liability insurance which the Corporation believes would cover any damages which may become payable by LDC in connection with the action.

On December 20, 2010, LDC was served with a statement of claim by the City seeking damages in the amount of $2,000,000 as a result of the fire at 2 Secord Avenue. A statement of defence and third party claim have been served. Given the preliminary status of this action, it is not possible to reasonably quantify the effect, if any, of this action on the financial performance of the Corporation. If damages were awarded, LDC would make a claim under its liability insurance which the Corporation believes would cover any damages which may become payable by LDC in connection with the action.

By order of the court, the above actions and a smaller non-class action commenced in April 2009 involving the same incident will be tried at the same time or consecutively.

2369 Lakeshore Boulevard West

A third party action was commenced against LDC in October 2009 in the Ontario Superior Court of Justice under the Class Proceedings Act seeking damages in the amount of $30,000,000 as compensation for damages allegedly suffered as a result of a fire in the electrical room at 2369 Lakeshore Boulevard West on March 19, 2009. Subsequently, in March 2010, the plaintiff in the main action amended its statement of claim to add LDC as a defendant. The plaintiff in the main action seeks damages in the amount of $10,000,000 from LDC. Both actions are at a preliminary stage and the certification hearing is scheduled for September 2012. Statements of defence to the main action and to the third party claim have not been filed. Accordingly, given the preliminary status of these actions, it is not possible at this time to reasonably quantify the effect, if any, of these actions on the financial performance of the Corporation. If damages were awarded, LDC would make a claim under its liability insurance which the Corporation believes would cover any damages which may become payable by LDC in connection with these actions.

Another third party action was commenced against LDC in October 2009 in the Ontario Superior Court of Justice seeking damages in the amount of $30,000,000 as compensation for damages allegedly suffered as a result of the fire at 2369 Lakeshore Boulevard West. Subsequently, in March 2010, the plaintiff in the main action amended its statement of claim to add LDC as a defendant. The plaintiff in the main action seeks damages in the amount of $400,000 from LDC. LDC has filed a statement of defence, crossclaim and counterclaim. Examinations for discovery have not taken place but are to be completed by February 29, 2012 pursuant to a court ordered timetable. Accordingly, given the preliminary status of these actions, it is not possible at this time to reasonably quantify the effect, if any, of these actions on the financial performance of the Corporation. If damages were awarded, LDC would make a claim under its liability insurance which the Corporation believes would cover any damages which may become payable by LDC in connection with these actions.

On August 29, 2011, LDC was served with a statement of claim by the owner of the building and the property management company for the building seeking damages in the amount of $2,000,000 as a result of the fire at 2369 Lakeshore Boulevard West. LDC has filed a statement of defence and counterclaim. Given the preliminary status of this action, it is not possible to reasonably quantify the effect, if any, of this action on the financial performance of the Corporation. If damages were awarded, LDC would make a claim under its liability insurance which the Corporation believes would cover any damages which may become payable by LDC in connection with the action.

Adamopoulos

An action was commenced against LDC in November 2004 in the Ontario Superior Court of Justice seeking damages in the amount of $7,750,000 as compensation for damages allegedly suffered as a result of a motor vehicle accident involving an LDC vehicle on January 9, 2001. The plaintiff's motion increasing its claim for damages to $23,790,000 was granted on July 7, 2010. This matter has been settled and a court order has been issued dismissing the action and all related claims by payment of a total amount of approximately $4,550,000. LDC's liability insurance covered the settlement amount.

b) OEB PILs Proceeding

The OEB conducted a review of the PILs variances accumulated in regulatory variance accounts for the period from October 1, 2001 to April 30, 2006 for certain MEUs. On June 24, 2011, the OEB issued its decision for these MEUs and provided guidelines for the calculation and further disposition of the balances accumulated in the PILs regulatory variance accounts.

LDC has reviewed the balances of its PILs regulatory variance accounts and applied the guidelines provided by the OEB. As at December 31, 2011, LDC estimated its liability at approximately $2,779,000. This balance has been recorded in the Corporation's consolidated financial statements. LDC intends to apply for disposition of this balance in 2012. The amount to be approved by the OEB will be based on the OEB's interpretation and application of its guidelines and the final balance which is yet to be approved by the OEB could differ materially from LDC's estimation of its liability.

c) Payments in Lieu of Additional Municipal and School Taxes

The Ministry of Finance has issued assessments in respect of payments in lieu of additional municipal and school taxes under section 92 of the Electricity Act that are in excess of the amounts LDC believes are payable. The dispute arose as a result of inaccurate information incorporated into Ontario Regulation 224/00. The Corporation has worked with the Ministry of Finance to resolve this issue, and as a result the Ministry of Finance issued Ontario Regulation 423/11 on August 31, 2011. The new regulation revoked Ontario Regulation 224/00 and corrected inaccurate information retroactively to 1999.

The balance assessed by the Ministry of Finance on its most recent statement of account amounts to approximately $10,043,000 above the balance accrued by the Corporation. While the Corporation expects that reassessments will be issued as a consequence of the change in regulation, there can be no assurance that the Corporation will not have to pay the full assessed balance in the future.

23. NET INCOME PER SHARE

The weighted daily average number of shares outstanding as at December 31, 2011 was 1,000 [December 31, 2010 - 1,000]. Basic and fully diluted net income per share was determined by dividing the net income for the year by the weighted daily average number of shares outstanding.

24. COMPARATIVE CONSOLIDATED FINANCIAL STATEMENTS

Certain comparative amounts of the consolidated financial statements have been reclassified from statements previously presented to conform to the presentation of the 2011 consolidated financial statements.

25. SUBSEQUENT EVENTS

a) Street Lighting Activities

On January 1, 2012, the Corporation completed the transfer of street lighting assets to LDC for a purchase price of $28,460,000, subject to post closing adjustment and transaction costs *[note 2[b]]*.

b) Electricity Distribution Rates

On January 5, 2012, the OEB rendered its decision on the preliminary issue and dismissed LDC's cost of service 2012-2014 Rate Application. In its decision, the OEB found that LDC was not permitted to deviate from the standard incentive regulation mechanism framework cycle, and LDC will therefore be required to file its request for electricity distribution rates commencing on May 1, 2012 pursuant to the formulaic adjustment and the incremental capital module provided for under the incentive regulation mechanism framework *[note 2[a]]*.

On January 25, 2012, LDC filed with the OEB a motion to review the OEB's January 5, 2012 decision.

On February 6, 2012, LDC filed a notice of appeal with the Ontario Divisional Court regarding the OEB's January 5, 2012 decision.

Pursuant to the OEB's decision of January 5, 2012, LDC is currently preparing an application for electricity distribution rates using the incentive regulation mechanism framework, including the filing of an incremental capital module. The quantum of this application is consistent with the capital program spending levels previously approved by the OEB for the 2011 Rate Year.

Under the incentive regulation mechanism framework, LDC has to significantly reduce its costs structure, and in particular its operating expenses, in order to meet its financial obligations. Accordingly, in the first quarter of 2012, LDC began implementing a restructuring program aimed at reducing its operating costs in the future. The main component of this restructuring program is a workforce reduction plan targeting both union and management employees. As at March 2, 2012, the costs incurred as a result of the restructuring program amounted to approximately $19,300,000, which were mainly related to employee severance and buy-out costs.

The Corporation continues to assess all of the impacts related to the imposition by the OEB of the incentive regulation mechanism framework, which impacts may include additional restructuring costs. The incremental restructuring costs could have a material impact on the Corporation's consolidated financial statements in the future.

c) Christian Helm Class Action

On February 1, 2012, prior to the release of the decisions on the summary judgment motions, the parties reached a settlement of the matter, which settlement now requires court approval. The Settlement Approval Hearing is scheduled for April 30, 2012. If the settlement receives court approval, damages and costs of approximately $6,000,000 shall be paid by LDC. In 2010, the Corporation accrued a liability to cover the expected settlement.

If the settlement does not receive court approval, the decision on the cross summary judgment motions will be released. In this event, if the court finds a breach of the Interest Act, subject to appeals, the proceeding will continue, and LDC will rely on other defences. While LDC believes it has a defence to this claim, there is no guarantee that it will be successful in defending the action and therefore, the outcome of this proceeding could have a material impact on the Corporation's consolidated financial statements and results of operations *[note 22[a]]*.

d) Dividends

On March 2, 2012, the board of directors of the Corporation declared dividends in the amount of $28,966,000. The dividends are comprised of $22,966,000 with respect to net income for the year ended December 31, 2011, payable to the City on March 12, 2012, and $6,000,000 with respect to the first quarter of 2012, payable to the City on March 30, 2012 *[note 19]*.

Toronto Hydro-Electric System Limited
EB-2012-0064
Tab 6C
Schedule 10-1
Appendix B
Filed: 2012 Oct 5
(35 pages)

TORONTO HYDRO Corporation

CONSOLIDATED FINANCIAL STATEMENTS
MARCH 31, 2012

INTERIM CONSOLIDATED BALANCE SHEETS

[in thousands of Canadian dollars, unaudited]

	As at March 31, 2012 $	As at December 31, 2011 $
		[note 24]
ASSETS		
Current		
Cash and cash equivalents	**133,132**	154,256
Investments	**-**	34,002
Accounts receivable, net of allowance for doubtful accounts *[note 16[b]]*	**210,369**	183,272
Unbilled revenue *[note 16[b]]*	**243,890**	262,058
Income tax receivable	**14,578**	11,312
Inventories *[note 5]*	**6,617**	6,891
Regulatory assets *[note 9]*	**2,668**	-
Other assets *[note 6]*	**6,877**	5,409
Total current assets	**618,131**	657,200
Property, plant and equipment, net *[note 7]*	**2,412,684**	2,399,497
Intangible assets, net *[note 8]*	**129,396**	112,982
Regulatory assets *[note 9]*	**151,137**	143,038
Other assets *[note 10]*	**12,054**	12,423
Deferred income tax assets *[note 9]*	**197,487**	202,367
Total assets	**3,520,889**	3,527,507
LIABILITIES AND SHAREHOLDER'S EQUITY		
Current		
Accounts payable and accrued liabilities *[note 16[b]]*	**424,071**	412,412
Restructuring accrual *[note 12]*	**16,640**	-
Customers' advance deposits	**43,318**	40,238
Deferred revenue	**21,831**	13,359
Post-retirement benefits *[note 14]*	**8,226**	7,915
Other liabilities *[note 21]*	**1,937**	2,182
Regulatory liabilities *[note 9]*	**-**	7,293
Total current liabilities	**516,023**	483,399
Restructuring accrual *[note 12]*	**8,022**	-
Customers' advance deposits	**13,366**	15,800
Debentures *[note 13]*	**1,469,542**	1,469,527
Post-retirement benefits *[note 14]*	**238,277**	236,411
Other liabilities *[note 21]*	**11,003**	11,301
Regulatory liabilities *[note 9]*	**199,250**	203,919
Asset retirement obligations *[note 15]*	**4,950**	4,902
Total liabilities	**2,460,433**	2,425,259
Commitments, contingencies and subsequent events *[notes 21, 22 and 26]*		
Shareholder's equity		
Share capital *[note 19]*	**567,817**	567,817
Retained earnings	**492,639**	534,431
Total shareholder's equity	**1,060,456**	1,102,248
Total liabilities and shareholder's equity	**3,520,889**	3,527,507

The accompanying notes are an integral part of the interim consolidated financial statements.

INTERIM CONSOLIDATED STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME (LOSS)

[in thousands of Canadian dollars, except for per share amounts, unaudited]

	Three months ended March 31, 2012 $	2011 $
		[note 24]
Revenues	**699,660**	704,188
Costs		
Purchased power	**562,430**	560,819
Operating expenses	**68,182**	66,175
Depreciation and amortization	**35,428**	33,472
	666,040	660,466
Income before the following:	**33,620**	43,722
Net financing charges	**(18,650)**	(18,896)
Gain on disposals of property, plant and equipment	**-**	2,964
Restructuring costs *[note 12]*	**(27,796)**	-
Income (loss) before income taxes	**(12,826)**	27,790
Income tax expense *[note 18]*	**-**	2,338
Net income (loss) and comprehensive income (loss) for the period	**(12,826)**	25,452
Basic and fully diluted net income (loss) per share *[note 23]*	**(12,826)**	25,452

INTERIM CONSOLIDATED STATEMENTS OF SHAREHOLDER'S EQUITY

[in thousands of Canadian dollars, unaudited]

	Three months ended March 31, 2012 $	2011 $
Share capital *[note 19]*	**567,817**	567,817
Retained earnings, beginning of period	**534,431**	471,562
Net income (loss) for the period	**(12,826)**	25,452
Dividends *[notes 19 and 20]*	**(28,966)**	(14,063)
Retained earnings, end of period	**492,639**	482,951
Total shareholder's equity	**1,060,456**	1,050,768

The accompanying notes are an integral part of the interim consolidated financial statements.

TORONTO HYDRO Corporation

INTERIM CONSOLIDATED STATEMENTS OF CASH FLOWS

[in thousands of Canadian dollars, unaudited]

	Three months ended March 31, 2012 $	Three months ended March 31, 2011 $
OPERATING ACTIVITIES		
Net income (loss) for the period	**(12,826)**	25,452
Adjustments for non-cash items		
Depreciation and amortization	**35,428**	33,472
Change in other non-current assets	**279**	323
Change in other non-current liabilities	**(1,662)**	(380)
Restructuring accrual	**8,022**	-
Post-retirement benefits	**2,177**	11,043
Deferred income taxes	**12**	(291)
Gain on disposals of property, plant and equipment	**-**	(2,964)
Changes in non-cash working capital balances		
Increase in accounts receivable	**(27,097)**	(56,310)
Decrease in unbilled revenue	**18,168**	3,595
Increase in income tax receivable	**(3,266)**	(2,895)
Decrease in inventories	**274**	66
Increase in other current assets	**(1,468)**	(2,974)
Increase in accounts payable and accrued liabilities	**13,026**	35,137
Increase in restructuring accrual	**16,640**	-
Increase in deferred revenue	**8,472**	2,212
Decrease in other current liabilities	**(245)**	(157)
Net cash provided by operating activities	**55,934**	45,329
INVESTING ACTIVITIES		
Purchase of property, plant and equipment *[note 7]*	**(43,301)**	(82,956)
Purchase of intangible assets *[note 8]*	**(22,077)**	(17,392)
Purchase of investments	**-**	(50,027)
Proceeds from investments	**34,000**	-
Net change in regulatory assets and liabilities	**(17,861)**	(10,295)
Proceeds on disposals of property, plant and equipment	**501**	2,154
Net cash used in investing activities	**(48,738)**	(158,516)
FINANCING ACTIVITIES		
Dividends paid *[notes 19 and 20]*	**(28,966)**	(14,063)
Increase (decrease) in customers' advance deposits	**646**	(6,806)
Net cash used in financing activities	**(28,320)**	(20,869)
Net decrease in cash and cash equivalents during the period	**(21,124)**	(134,056)
Cash and cash equivalents, beginning of period	**154,256**	330,151
Cash and cash equivalents, end of period	**133,132**	196,095
Supplementary cash flow information		
Total interest paid	**263**	32
Total income taxes paid	**3,330**	5,524

The accompanying notes are an integral part of the interim consolidated financial statements.

1. INCORPORATION

On June 23, 1999, Toronto Hydro Corporation [the "Corporation"] was incorporated under the *Business Corporations Act* (Ontario) [the "OBCA"] and is wholly-owned by the City of Toronto [the "City"]. The incorporation was required in accordance with the provincial government's *Electricity Act, 1998* (Ontario) ["Electricity Act"].

The Corporation supervises the operations of, and provides corporate, management services and strategic direction to two subsidiaries incorporated under the OBCA and wholly-owned by the Corporation:

[i] Toronto Hydro-Electric System Limited ["LDC"] (incorporated June 23, 1999) – distributes electricity to customers located in the City and is subjected to rate regulation. LDC is also engaged in the delivery of Conservation and Demand Management ["CDM"] activities; and

[ii] Toronto Hydro Energy Services Inc. (incorporated June 23, 1999) – provides street lighting services.

The principal business of the Corporation and its subsidiaries is the distribution of electricity by LDC.

2. BASIS OF PRESENTATION

These unaudited interim consolidated financial statements of the Corporation have been prepared in accordance with United States ["US"] Generally Accepted Accounting Principles ["GAAP"] with respect to the preparation of interim financial information, and are presented in Canadian dollars. The disclosures in these statements do not conform in all respects to the requirements of US GAAP for annual consolidated financial statements. These are the Corporation's first US GAAP interim consolidated financial statements. The Corporation's annual and interim consolidated financial statements were prepared in accordance with Canadian GAAP until December 31, 2011. The comparative consolidated financial statements have been adjusted from statements previously presented to conform to the presentation of the first interim 2012 consolidated financial statements in accordance with US GAAP, retroactively. The Corporation's first US GAAP annual consolidated financial statements will be dated December 31, 2012.

A reconciliation of the consolidated balance sheets between Canadian GAAP and US GAAP as at January 1, 2011 and December 31, 2011 and a reconciliation of net income for the three months ended March 31, 2011 accompanies the interim consolidated financial statements *[note 24]*.

3. REGULATION

In April 1999, the government of Ontario began restructuring the Province of Ontario ["Ontario"]'s electricity industry. Under regulations passed pursuant to the restructuring, LDC and other electricity distributors have been purchasing their electricity from the wholesale market administered by the Independent Electricity System Operator ["IESO"] and recovering the costs of electricity and certain other costs at a later date in accordance with procedures mandated by the Ontario Energy Board [the "OEB"].

The OEB has regulatory oversight of electricity matters in Ontario. The *Ontario Energy Board Act, 1998* (Ontario) [the "OEB Act"] sets out the OEB's authority to issue a distribution licence which must be obtained by owners or operators of an electricity distribution system in Ontario. The OEB prescribes licence requirements and conditions including, among other things, specified accounting records, regulatory accounting principles, separation of accounts for separate businesses and filing process requirements for rate-setting purposes.

The OEB's authority and responsibilities include the power to approve and fix rates for the transmission and distribution of electricity, the power to provide continued rate protection for rural and remote electricity customers and the responsibility for ensuring that electricity distribution companies fulfill their obligations to connect and service customers.

Regulatory developments in Ontario's electricity industry, including current and possible future consultations between the OEB and interested stakeholders, may affect LDC's electricity distribution rates and other permitted recoveries in the future.

LDC is required to charge its customers for the following amounts (all of which, other than distribution charges, represent a pass through of amounts payable to third parties):

[i] *Distribution Charges*. Distribution charges are designed to recover the costs incurred by LDC in delivering electricity to customers and the OEB-allowed rate of return. Distribution charges are regulated by the OEB and are comprised of a fixed charge and a usage-based (consumption) charge. The volume of electricity consumed by LDC's customers during any period is governed by events largely outside LDC's control (principally, sustained periods of hot or cold weather which increase the consumption of electricity and sustained periods of moderate weather which decrease the consumption of electricity).

[ii] *Electricity Price and Regulated Adjustments*. The electricity price and regulated adjustments represent the pass through of the commodity and other costs of electricity.

[iii] *Retail Transmission Rate*. The retail transmission rate represents a pass through of wholesale costs incurred by distributors in respect of the transmission of electricity from generating stations to local areas. Retail transmission rates are regulated by the OEB.

[iv] *Wholesale Market Service Charge*. The wholesale market service charge represents a pass through of various wholesale market support costs. Retail rates for the recovery of wholesale market service charges are regulated by the OEB.

LDC is required to satisfy and maintain prudential requirements with the IESO, which include credit support with respect to outstanding market obligations in the form of letters of credit, cash deposits or guarantees from third parties with prescribed credit ratings.

a) Electricity Distribution Rates

LDC's electricity distribution rates are typically effective from May 1 to April 30 of the following year. Accordingly, for the first three months of 2012, distribution revenue was based on electricity distribution rates approved for the May 1, 2011 to April 30, 2012 rate year [the "2011 Rate Year"].

LDC's electricity distribution rates for the 2011 Rate Year were determined through an application under the Cost of Service ["COS"] framework. The COS framework sets electricity distribution rates using a detailed examination of evidence and an assessment of the costs incurred by an electricity distributor to provide its service to its customers.

On July 7, 2011, the OEB issued its decision regarding LDC's electricity distribution rates for the 2011 Rate Year. The decision provided for a distribution revenue requirement and rate base of $522,044,000 and $2,298,227,000, respectively. In addition, the decision provided for capital program spending levels and operating, maintenance and administration spending levels of $378,800,000 and $238,000,000, respectively.

On August 26, 2011, LDC filed a rate application, following the COS framework, with the OEB seeking approval of separate and successive revenue requirements and corresponding electricity distribution rates for three rate years commencing on May 1, 2012, May 1, 2013 and May 1, 2014 [the "2012-2014 Rate Application"]. The requested distribution revenue requirements for these rate years were $571,369,000, $639,492,000, and $712,777,000, respectively, and the expected rate bases for these rate years were $2,636,291,000, $3,053,499,000, and $3,503,165,000, respectively.

Pursuant to the Incentive Regulation Mechanism ["IRM"] framework, the OEB established, as a preliminary issue in the 2012-2014 Rate Application, that it would consider the question of whether the application filed by LDC under the COS framework was acceptable or whether it should be dismissed. The IRM framework provides for an adjustment to an electricity distributor's rates based on a formulaic calculation with the possibility to request an Incremental Capital Module ["ICM"] to address specific capital expenditure needs not covered by the formulaic calculation. The review of an ICM application is done by the OEB following defined criteria, such as materiality, causation and prudence.

LDC filed evidence supporting its position for electricity distribution rates to be set under the COS framework as part of its 2012-2014 Rate Application. The OEB established a process by which a portion of LDC's evidence was tested during an oral hearing held in November 2011.

On January 5, 2012, the OEB rendered its decision on the preliminary issue and dismissed LDC's COS framework 2012-2014 Rate Application. In its decision, the OEB found that LDC was not permitted to deviate from the standard IRM framework cycle. Accordingly, LDC was required to file its request for electricity distribution rates commencing on May 1, 2012 pursuant to the IRM framework and to use the ICM to request the capital needed for infrastructure renewal *[note 26[a]]*.

On January 25, 2012, LDC filed with the OEB a motion to review the OEB's January 5, 2012 decision.

On February 6, 2012, LDC filed a notice of appeal with the Ontario Divisional Court regarding the OEB's January 5, 2012 decision.

b) Conservation and Demand Management Activities

On March 31, 2010, the Minister of Energy and Infrastructure of Ontario, under the guidance of sections 27.1 and 27.2 of the OEB Act, directed the OEB to establish CDM targets to be met by electricity distributors. Accordingly, on November 12, 2010, the OEB amended LDC's distribution licence to require LDC, as a condition of its licence, to achieve 1,304 Gigawatt-Hours of energy savings and 286 Megawatts of summer peak demand savings, over the period beginning January 1, 2011 through December 31, 2014.

Effective January 1, 2011, LDC entered into an agreement with the Ontario Power Authority ["OPA"] to deliver CDM programs in the amount of approximately $50,000,000 extending from January 1, 2011 to December 31, 2014. As at March 31, 2012, LDC received approximately $27,620,000 [December 31, 2011 - $19,875,000] from the OPA for the delivery of CDM programs. All programs to be delivered are fully funded and paid in advance by the OPA. These programs are expected to support the achievement of the mandatory CDM targets described above.

4. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

The interim consolidated financial statements of the Corporation have been prepared in accordance with US GAAP, including accounting principles prescribed by the OEB in the "Accounting Procedures Handbook for Electricity Distributors" [the "AP Handbook"], and reflect the significant accounting policies summarized below:

a) Basis of consolidation

The interim consolidated financial statements include the accounts of the Corporation and its wholly-owned subsidiaries. All intercompany balances and transactions have been eliminated.

b) Regulation

The following regulatory treatments have resulted in accounting treatments which differ from US GAAP for enterprises operating in an unregulated environment:

Regulatory Assets and Liabilities

The Corporation has determined that its assets and liabilities arising from rate-regulated activities qualify for the application of regulatory accounting treatment in accordance with Financial Accounting Standards Board ["FASB"] Accounting Standards Codification 980 – "Regulated Operations" ["ASC 980"]. Under rate-regulated accounting ["RRA"], the timing and recognition of certain expenses and revenues may differ from those otherwise expected under US GAAP in order to appropriately reflect the economic impact of regulatory decisions regarding the Corporation's regulated revenues and expenditures. These timing differences are recorded as regulatory assets and regulatory liabilities on the Corporation's consolidated balance sheets and represent existing rights and obligations regarding cash flows expected to be recovered from or refunded to customers, based on decisions and approvals by the OEB. Regulatory assets and liabilities can be recognized for rate-setting and financial reporting purposes only if the OEB directs the relevant regulatory treatment or if future OEB direction is judged to be probable. In the event that the disposition of these balances was assessed to no longer be probable, the balances would be recorded in the Corporation's consolidated statements of operations and comprehensive income (loss) in the period that the assessment is made. The measurement of regulatory assets and liabilities is subject to certain estimates and assumptions, including assumptions made in the interpretation of the regulation and the OEB's decisions.

Contributions in aid of construction

Capital contributions received are used to finance additions to property, plant and equipment of LDC. According to the accounting principles prescribed by the OEB in the AP Handbook, capital contributions received are treated as a "credit" to property, plant and equipment. The amount is subsequently depreciated by a charge to accumulated depreciation and a credit to depreciation expense at an equivalent rate to that used for the depreciation of the related property, plant and equipment.

Allowance for funds used during construction

The AP Handbook provides for the inclusion of an Allowance for Funds Used During Construction ["AFUDC"] when capitalizing construction-in-progress assets, until such time as the asset is substantially complete. A concurrent credit of the same amount is made to net financing charges when the allowance is capitalized. The interest rate for capitalization is prescribed by the OEB and modified on a periodic basis, and is applied to the balance of the construction-in-progress assets on a simple interest basis. The interest rate for capitalization for the period from January 1 to March 31, 2012 was 3.92% [January 1 to March 31, 2011 - 4.29%]. AFUDC is included in property, plant and equipment, intangible assets, and construction-in-progress assets for financial reporting purposes, charged to operations through depreciation and amortization expense over the service life of the related assets and recovered through future revenue.

[all tabular amounts in thousands of Canadian dollars, unaudited]

c) Cash and cash equivalents

Cash and cash equivalents include cash in bank accounts and short-term investments with terms to maturity of 90 days or less from their date of acquisition.

d) Accounts receivable

Accounts receivable are recorded at the invoiced amount and do not bear interest. The carrying amount of accounts receivable is reduced through an allowance for doubtful accounts and the amount of the related impairment loss is recognized in the consolidated statements of operations and comprehensive income (loss). Subsequent recoveries of receivables previously provisioned and written off are credited to the consolidated statements of operations and comprehensive income (loss). Management estimates uncollectible accounts receivable after considering historical loss experience and the characteristics of existing accounts.

e) Investments

Investments with terms to maturity of greater than 90 days from their date of acquisition are classified as held to maturity and included in current assets.

f) Inventories

Inventories consist primarily of small consumable materials mainly related to the maintenance of the electricity distribution infrastructure. The Corporation classifies all major construction related components of its electricity distribution system infrastructure to property, plant and equipment. Once capitalized, these items are not depreciated until they are put into service. Inventories are carried at the lower of cost and market, with cost determined on an average cost basis net of a provision for obsolescence.

g) Property, plant and equipment

Property, plant and equipment are stated at cost and are removed from the accounts at the end of their estimated average service lives, except in those instances where specific identification allows their removal at retirement or disposition.

In the event that facts and circumstances indicate that property, plant and equipment may be impaired, an evaluation of recoverability is performed. For purposes of such an evaluation, the estimated future undiscounted cash flows associated with the asset are compared to the carrying amount of the asset to determine if a write-down is required. The impairment loss is measured as the amount by which the carrying amount of the asset exceeds its fair value, which is determined by the estimated future discounted cash flows.

Depreciation is provided on a straight-line basis over the estimated service lives at the following annual rates:

Distribution lines	1.7% to 5.0%
Transformers	3.3% to 5.0%
Stations	2.5% to 10.0%
Meters	2.5% to 6.7%
Buildings	1.3% to 5.0%
Rolling stock	12.5% to 25.0%

[all tabular amounts in thousands of Canadian dollars, unaudited]

Other capital assets	4.0% to 20.0%
Equipment and tools	10.0% to 16.7%
Assets under capital lease	14.3% to 25.0%
Computer hardware	16.7% to 25.0%
Communications	10.0% to 20.0%

Construction in progress relate to assets not currently in use and therefore are not depreciated.

h) Intangible assets

Effective January 1, 2012, the Corporation revised its estimate of useful life for its Customer Care and Billing Customer Information System from 5 years to 10 years due to additional analysis completed related to the useful life assessment. This change has been accounted for on a prospective basis in the interim consolidated financial statements effective January 1, 2012. It is estimated that this change in estimate will increase intangible assets and decrease amortization expense by approximately $1,000,000 for the quarter ended March 31, 2012 and approximately $4,000,000 for the year ended December 31, 2012, and is expected to impact amortization expense proportionately in future periods.

Intangible assets are stated at cost. Amortization is provided on a straight-line basis over their estimated service lives at the following annual rates:

Computer software	10.0% to 25.0%
Contributions	4.0%

Software in development and contributions for work in progress relate to assets not currently in use and therefore are not amortized.

i) Deferred debt issuance costs

Debt issuance costs arising from the Corporation's debenture offerings are capitalized within Other assets on the consolidated balance sheet. The deferred charge is amortized over the life of the debenture, using the effective interest method of amortization and included in net financing charges.

j) Restructuring

Restructuring charges are recorded based upon planned employee termination dates, site closure and consolidation plans, and contract terminations. Restructuring charges can include severance costs to eliminate a specified number of employee positions, infrastructure charges to vacate facilities and consolidate operations, and contract cancellation costs. The timing of associated cash payments is dependent upon the type of restructuring charge and can extend over a multi-year period.

k) Workplace Safety and Insurance Act

The Corporation is a Schedule 1 employer for workers' compensation under the *Workplace Safety and Insurance Act, 1997* (Ontario) [the "WSIA"]. As a Schedule 1 employer under the WSIA, the Corporation is required to pay annual premiums into an insurance fund established under the WSIA and recognizes expenses based on funding requirements.

l) Revenue recognition

Revenues from the sale of electricity are recorded on a basis of cyclical billings and also include unbilled revenues accrued in respect of electricity delivered but not yet billed.

Other revenues, which include revenues from electricity distribution related services, revenues from the delivery of street lighting services and revenues from demand billable activities are recognized as the services are rendered.

m) Financial instruments

At inception, all financial instruments which meet the definition of a financial asset or financial liability are recorded at fair value, unless fair value cannot be reliably determined. Gains and losses related to the measurement of financial instruments are reported in the consolidated statements of operations and comprehensive income (loss). Subsequent measurement of each financial instrument will depend on the consolidated balance sheet classification elected by the Corporation. The fair value of a financial instrument is the amount of consideration that would be agreed upon in an arm's length transaction between willing parties.

The following summarizes the accounting classification the Corporation has elected to apply to each of its significant categories of financial instruments:

Cash equivalents and short-term investments	Held for Trading
Investments	Held to Maturity
Accounts receivable and unbilled revenue	Loans and Receivables
Accounts payable and accrued liabilities	Other Financial Liabilities
Obligations under capital lease	Other Financial Liabilities
Customers' advance deposits	Other Financial Liabilities
Debentures	Other Financial Liabilities

The Corporation uses the following methods and assumptions to estimate the fair value of each class of financial instruments for which carrying amounts are included in the consolidated balance sheet:

- Cash equivalents, comprising short-term investments, are classified as "Held for Trading" and are measured at fair value. The carrying amounts approximate fair value because of the short maturity of these instruments.

- Investments are classified as "Held to Maturity" and are measured at amortized cost, which, upon initial recognition, is considered equivalent to fair value. The carrying amounts approximate fair value because of the short maturity of these instruments.

- Accounts receivable and unbilled revenue are classified as "Loans and Receivables" and are measured at amortized cost, which, upon initial recognition, are considered equivalent to fair value. Subsequent measurements are recorded at amortized cost using the effective interest rate method. The carrying amounts approximate fair value because of the short maturity of these instruments.

- Accounts payable and accrued liabilities are classified as "Other Financial Liabilities" and are initially measured at their fair value. Subsequent measurements are recorded at amortized cost using the effective interest rate method. The carrying amounts approximate fair value because of the short maturity of these instruments.

- Obligations under capital lease are classified as "Other Financial Liabilities" and are initially measured at their fair value. Subsequent measurements are based on a discounted cash flow analysis and approximate their carrying value as management believes that the fixed interest rates are representative of current market rates.

- Customers' advance deposits are classified as "Other Financial Liabilities" and are initially measured at their fair value. Subsequent measurements are recorded at amortized cost using the effective interest rate method. The carrying amounts approximate fair value because of the short maturity of the current portion, and the discounted long-term portion approximates the carrying value, taking into account interest accrued on the outstanding balance.

- Debentures are classified as "Other Financial Liabilities" and are initially measured at their fair value. The carrying amounts of the debentures are carried at amortized cost, based on an initial fair value as determined at the time using a quoted market price for similar debt instruments. The fair value of the debentures is calculated by discounting the related cash flows at the estimated yield to maturity of similar debt instruments *[note 16[a]]*. While the Corporation has the option to redeem some or all of the debentures at its discretion, this option has no value and has not been recorded in the consolidated financial statements.

n) Fair value measurements

The Corporation utilizes valuation techniques that maximize the use of observable inputs and minimize the use of unobservable inputs when measuring fair value. A fair value hierarchy exists that prioritizes observable and unobservable inputs used to measure fair value. Observable inputs reflect market data obtained from independent sources, while unobservable inputs reflect the Corporation's assumptions with respect to how market participants would price an asset or liability. The fair value hierarchy includes three levels of inputs that may be used to measure fair value:

- *Level 1*: An active market for the asset or liability is a market in which transactions for the asset or liability occur with sufficient frequency and volume to provide pricing information on an ongoing basis;

- *Level 2*: Other than quoted prices included within Level 1 that are observable for the assets or liabilities, either directly or indirectly; and

- *Level 3*: Unobservable inputs, supported by little or no market activity, used to measure the fair value of the assets or liabilities to the extent that observable inputs are not available.

o) Employee future benefits

Multi-employer pension plan

The Corporation provides a pension plan for its full-time employees through the Ontario Municipal Employees Retirement System ["OMERS"]. OMERS is a multi-employer, contributory, defined benefit pension plan established in 1962 by Ontario for employees of municipalities, local boards and school boards. Both participating employers and employees are required to make plan contributions based on participating employees' contributory earnings. The OMERS plan is accounted for as a defined contribution plan where the Corporation recognizes the expense related to this plan as contributions are made. The Corporation is not responsible for any other contractual obligations other than the contributions.

As at March 31, 2012, OMERS had approximately 420,000 members, of whom approximately 1,600 are current employees of the Corporation.

Post-retirement benefits other than pension

The Corporation has a number of unfunded benefit plans providing post-retirement benefits (excluding pension) to its employees. The Corporation pays certain medical, dental and life insurance benefits under unfunded defined benefit plans on behalf of its retired employees. The Corporation pays accumulated sick leave credits, up to certain established limits based on service, in the event of retirement, termination or death of certain employees.

The Corporation measures its accumulated benefit obligation for accounting purposes as at December 31 of each year. The latest actuarial valuation was performed as at January 1, 2010.

The cost of providing benefits under the defined benefit plans is determined using the projected unit credit method and based on assumptions that reflect management's best estimate. All actuarial gains and losses and prior service costs are recognized immediately in other comprehensive income ["OCI"] (loss) and subsequently reclassified to a regulatory asset on the consolidated balance sheet. This results in the full recognition of the benefit obligation as a liability on the consolidated balance sheet.

Actuarial gains or losses are amortized into net periodic benefit cost for the current period when the net cumulative unrecognized actuarial gains or losses in the regulatory asset at the end of the previous reporting period exceed 10% of the accumulated benefit obligation at that date. These gains or losses are recognized over the expected average remaining service period of active employees participating in the plans.

The prior service costs in the regulatory asset are recognized as an expense on a straight-line basis over the average remaining service period of employees active at the date of amendment.

The effects of a curtailment loss are recognized in the consolidated statements of operations and comprehensive income (loss) when its occurrence is probable and reasonably estimable. The effects of a curtailment gain are recognized in the consolidated statements of operations and comprehensive income (loss) when the related employees terminate or the plan suspension or amendment is adopted. The effects of a settlement gain or loss are recognized in the consolidated statements of operations and comprehensive income (loss) in the period in which a settlement occurs.

p) Asset retirement obligations

The Corporation recognizes a liability for the future environmental remediation of certain properties and for future removal and handling costs for contamination in distribution equipment in service and in storage. Initially, the liability is measured at present value and the amount of the liability is added to the carrying amount of the related asset. In subsequent periods, the asset is depreciated and the liability is adjusted quarterly for the discount applied upon initial recognition of the liability and for changes in the underlying assumptions. The liability is recognized when the asset retirement obligation ["ARO"] is incurred and when the fair value is determined.

q) Customers' advance deposits

Electricity customer security deposits are cash collections from customers to guarantee the payment of energy bills. The electricity customer security deposits liability includes related interest amounts owed to the customers with the debit charged to net financing charges. Deposits that are refundable upon demand are classified as a current liability.

Security deposits on Offers to Connect and Supply Agreement are cash collections from expansion project customers to guarantee the payment of additional costs from these projects. This liability includes related interest amounts owed to the customers with the debit charged to net financing charges. Deposits are classified as a current liability when the Corporation no longer has an unconditional right to defer payment of the liability for at least twelve months after the reporting period.

r) Income Taxes

Under the Electricity Act, the Corporation is required to make payments in lieu of corporate income taxes ["PILs"] to the Ontario Electricity Financial Corporation. These payments are calculated in accordance with the *Income Tax Act* (Canada) and the *Taxation Act, 2007* (Ontario) (for years ending after 2008) or the *Corporations Tax Act* (Ontario) (for years ending prior to 2009) as modified by regulations made under the Electricity Act and related regulations. This effectively results in the Corporation paying taxes similar to what would be imposed under the federal and Ontario tax acts.

The Corporation uses the liability method of accounting for income taxes. Under the liability method, current income taxes payable are recorded based on taxable income. The Corporation recognizes deferred income tax assets and liabilities for the future tax consequences of events that have been included in the consolidated financial statements or income tax returns. Deferred income tax assets and liabilities are determined based on the difference between the carrying value of assets and liabilities on the consolidated balance sheet and their respective tax basis using the enacted tax rates by the consolidated balance sheet date in effect for the period in which the differences are expected to reverse. Deferred income tax assets are evaluated and if realization is not considered more likely than not, a valuation allowance is established.

ASC 980 requires the recognition of deferred income tax assets and liabilities and related regulatory liabilities and assets for the amount of deferred income taxes expected to be refunded to, or recovered from, customers in future electricity rates. As at March 31, 2012, LDC recorded a deferred income tax asset of $195,568,000 and a corresponding regulatory liability of $195,568,000 with respect to its rate-regulated activities *[note 9]*.

The benefits of the refundable apprenticeship and co-operative investment tax credits ["ITC"] are credited against the related expense in the consolidated statements of operations and comprehensive income (loss). All other types of ITCs are recorded as a reduction to income tax expense in the current periods to the extent that realization of such benefit is more likely than not.

s) Use of estimates

The preparation of the Corporation's unaudited interim consolidated financial statements in accordance with US GAAP requires management to make estimates and assumptions which affect the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities at the date of the interim consolidated financial statements and the reported amounts of revenues and expenses for the period. The estimates are based on historical experience, current conditions and various other assumptions that are believed to be reasonable under the circumstances, the results of which form the basis for making judgments about the carrying values of assets and liabilities as well as identifying and assessing the accounting treatment with respect to commitments and contingencies. Significant areas requiring the use of management estimates relate to unbilled revenue, regulatory assets and liabilities, environmental liabilities and AROs, employee future benefits, and revenue recognition. Actual results could differ from those estimates, including changes as a result of future decisions made by the OEB, the Ministry of Energy, or the Ministry of Finance of Ontario ["Ministry of Finance"].

t) Future Accounting Pronouncements

A number of new standards and interpretations are not yet effective for the period ended March 31, 2012. The Corporation continues to analyze these standards but has initially determined that the following could have a significant effect on the consolidated financial statements.

[all tabular amounts in thousands of Canadian dollars, unaudited]

In September 2011, the FASB issued Accounting Standards Update ["ASU"] No. 2011-09, "Compensation – Retirement Benefits – Multiemployer Plans (Subtopic 715-80): *Disclosures about an Employer's Participation in a Multiemployer Plan*" ["ASU 2011-09"]. The amendments require additional disclosures about employers' participation in these types of plans including information about the plan's funded status if it is readily available. ASU 2011-09 is effective for fiscal years ending after December 15, 2011 and will be applied retrospectively. Early adoption is permitted. The Corporation has elected to include the additional disclosures related to the multi-employer pension plans in the interim consolidated financial statements.

In December 2011, the FASB issued ASU No. 2011-11, "Balance Sheet (Topic 210): *Disclosures about Offsetting Assets and Liabilities*" ["ASU 2011-11"]. The amendments require an entity to disclose both gross and net information about financial instruments and transactions eligible for offset in the consolidated balance sheet. ASU 2011-11 is effective for fiscal years, and interim periods within those years, beginning on or after January 1, 2013. Retrospective application is required. The adoption of this amendment is expected to increase disclosures related to offsetting assets and liabilities and is not expected to have an impact to the Corporation's consolidated balance sheets.

5. INVENTORIES

Inventories consist of the following:

	March 31 2012 $	December 31 2011 $
Consumables, tools and other maintenance items	**1,641**	1,745
Fuses	**1,578**	1,625
Drums and reels	**917**	938
Other	**2,481**	2,583
	6,617	6,891

For the three months ended March 31, 2012, the Corporation recognized operating expenses of $2,132,000 related to inventory used to service electrical distribution assets [three months ended March 31, 2011 - $2,197,000].

6. CURRENT PORTION OF OTHER ASSETS

Current portion of other assets consist of the following:

	March 31 2012 $	December 31 2011 $
Prepaid expenses	**5,949**	4,487
Debt issuance costs	**928**	922
	6,877	5,409

[all tabular amounts in thousands of Canadian dollars, unaudited]

7. PROPERTY, PLANT AND EQUIPMENT, NET

Property, plant and equipment consist of the following:

	March 31 2012			December 31 2011		
	Cost $	Accumulated depreciation $	Net book value $	Cost $	Accumulated depreciation $	Net book value $
Land	**16,761**	**—**	**16,761**	16,761	—	16,761
Distribution lines	**2,867,476**	**1,444,733**	**1,422,743**	2,850,401	1,441,333	1,409,068
Transformers	**655,347**	**364,690**	**290,657**	652,102	360,398	291,704
Stations	**279,376**	**139,302**	**140,074**	277,905	137,246	140,659
Meters	**240,616**	**126,547**	**114,069**	238,459	124,117	114,342
Buildings	**156,048**	**64,154**	**91,894**	154,932	62,403	92,529
Rolling stock	**77,486**	**43,322**	**34,164**	78,016	43,154	34,862
Other capital assets	**69,587**	**45,145**	**24,442**	68,802	44,108	24,694
Equipment and tools	**44,485**	**32,311**	**12,174**	44,208	31,785	12,423
Assets under capital lease	**13,730**	**1,597**	**12,133**	14,269	1,251	13,018
Computer hardware	**47,026**	**36,643**	**10,383**	44,625	35,602	9,023
Communications	**31,825**	**24,641**	**7,184**	31,537	23,912	7,625
Construction in progress	**236,006**	**—**	**236,006**	232,789	—	232,789
	4,735,769	**2,323,085**	**2,412,684**	4,704,806	2,305,309	2,399,497

For the three months ended March 31, 2012, AFUDC in the amount of $284,000 [three months ended March 31, 2011 - $526,000] was capitalized to property, plant and equipment and credited to net financing charges.

As at March 31, 2012, the net book value of stranded meters related to the deployment of smart meters amounting to $19,661,000 [December 31, 2011 - $20,366,000] was included in property, plant and equipment. In the absence of rate regulation, property, plant and equipment would have been $19,661,000 lower as at March 31, 2012 [December 31, 2011 - $20,366,000 lower].

For the three months ended March 31, 2012, the Corporation recorded depreciation expense of $29,765,000 [three months ended March 31, 2011 - $28,964,000] of which $519,000 [three months ended March 31, 2011 - $45,000] related to assets under capital lease.

[all tabular amounts in thousands of Canadian dollars, unaudited]

8. INTANGIBLE ASSETS, NET

Intangible assets consist of the following:

	March 31 2012			December 31 2011		
	Cost $	Accumulated amortization $	Net book value $	Cost $	Accumulated amortization $	Net book value $
Computer software	**224,059**	**159,704**	**64,355**	222,598	154,186	68,412
Contributions	**14,059**	**1,585**	**12,474**	14,059	1,440	12,619
Software in development	**18,442**	—	**18,442**	15,598	—	15,598
Contributions for work in progress	**34,125**	—	**34,125**	16,353	—	16,353
	290,685	**161,289**	**129,396**	268,608	155,626	112,982

For the three months ended March 31, 2012, the Corporation acquired $22,077,000 of intangible assets [three months ended March 31, 2011 - $17,392,000]. All intangible assets are subject to amortization when they become available for use. Software in development and contributions for work in progress relate to assets not currently available for use and therefore are not amortized.

For the three months ended March 31, 2012, $1,460,000 of software in development was transferred to computer software [three months ended March 31, 2011 - $4,553,000].

For the three months ended March 31, 2012, AFUDC in the amount of $269,000 [three months ended March 31, 2011 - $440,000] was capitalized to intangible assets and credited to net financing charges.

For the three months ended March 31, 2012, the Corporation recorded amortization expense on intangible assets of $5,663,000 [three months ended March 31, 2011 - $4,508,000].

As at March 31, 2012, estimated future amortization expense related to intangible assets is as follows:

	$
2012 (1)	15,204
2013	15,692
2014	14,778
2015	13,825
2016	10,874

(1) The amount disclosed represents the period April 1, 2012 to December 31, 2012.

[all tabular amounts in thousands of Canadian dollars, unaudited]

9. REGULATORY ASSETS AND LIABILITIES

Regulatory assets consist of the following:

	March 31 2012 $	December 31 2011 $
Smart meters	**59,999**	61,422
Accounting policy changes	**63,757**	64,785
Settlement variances	**26,807**	14,119
Regulatory assets recovery account	**2,668**	931
Other	**574**	1,781
	153,805	143,038
Less: Current portion of regulatory assets	**2,668**	—
Long-term portion of regulatory assets	**151,137**	143,038

Regulatory liabilities consist of the following:

	March 31 2012 $	December 31 2011 $
Deferred income taxes	**195,568**	200,436
Regulatory assets recovery account	**187**	7,293
Income and other taxes variance account	**2,373**	2,365
Other	**1,122**	1,118
	199,250	211,212
Less: Current portion of regulatory liabilities	**—**	7,293
Long-term portion of regulatory liabilities	**199,250**	203,919

For the three months ended March 31, 2012, LDC disposed of approved net regulatory liabilities amounting to $8,848,000 through permitted distribution rate adjustments [three months ended March 31, 2011 - $7,125,000].

The regulatory assets and liabilities of the Corporation are as follows:

a) Smart Meters

The smart meters regulatory asset account relates to Ontario's decision to install smart meters throughout Ontario. LDC substantially completed its smart meter project as at December 31, 2010. In connection with this initiative, the OEB ordered LDC to record all expenditures and related revenues from 2008 to 2010 to a regulatory asset account and allowed LDC to keep the net book value of the stranded meters in property, plant and equipment. Effective January 1, 2011, LDC has recorded smart meter costs in property, plant and equipment and intangible assets as a regular distribution activity as directed by the OEB. LDC expects to apply to the OEB to transfer the 2008 to 2010 smart meter costs from regulatory assets to property, plant and equipment and intangible assets in 2012, as well as to apply to transfer the net book value of the stranded meters from property, plant and equipment to regulatory assets in the next COS application.

As at March 31, 2012, smart meter capital expenditures, net of accumulated depreciation, totalling $57,636,000 were recorded to regulatory assets [December 31, 2011 - $59,227,000]. These expenditures would otherwise have been recorded as property, plant and equipment and intangible assets under US GAAP for unregulated businesses. In the absence of rate regulation, property, plant and equipment and intangible assets would have been $53,677,000 and $3,959,000 higher, respectively, as at March 31, 2012 [December 31, 2011 - $54,825,000 and $4,402,000 higher, respectively].

For the three months ended March 31, 2012, smart meter depreciation expense of $1,590,000 [three months ended March 31, 2011 - $1,590,000] were deferred which would have been expensed under US GAAP for unregulated businesses. In the absence of rate regulation, for the three months ended March 31, 2012, depreciation expense would have been $1,590,000 higher [three months ended March 31, 2011 - $1,590,000 higher].

For the three months ended March 31, 2012, smart meter customer revenues of $1,432,000 were deferred [three months ended March 31, 2011 - $1,481,000]. In the absence of rate regulation, for the three months ended March 31, 2012, revenue would have been $1,432,000 higher [three months ended March 31, 2011 - $1,481,000 higher].

b) Accounting Policy Changes

This regulatory asset account relates to the accounting policy changes upon adoption of US GAAP, primarily related to the expected future electricity distribution charges to customers arising from timing differences in the recognition of actuarial losses and prior service costs of other post-retirement benefits *[note 24]*. The period in which recovery is expected cannot be determined at this time.

c) Settlement Variances

This account is comprised of the variances between amounts charged by LDC to customers, based on regulated rates, and the corresponding cost of non-competitive electricity service incurred by LDC. The settlement variances relate primarily to service charges, non-competitive electricity charges, imported power charges and the global adjustment. Accordingly, LDC has deferred the variances between the costs incurred and the related recoveries in accordance with the criteria set out in the accounting principles prescribed by the OEB in the AP Handbook.

The balance for settlement variances continues to be calculated and attracts carrying charges in accordance with the OEB's direction. For the three months ended March 31, 2012, settlement variances of $9,229,000 were disposed through rate adjustments [three months ended March 31, 2011 - $7,644,000].

d) Deferred Income Taxes

This regulatory liability account relates to the expected future electricity distribution rate reduction for customers arising from timing differences in the recognition of deferred tax assets *[note 4[r]]*.

As at March 31, 2012, LDC recorded a deferred income tax asset and a corresponding regulatory liability of $195,568,000 [December 31, 2011 - $200,436,000] with respect to its rate-regulated activities.

e) Regulatory Assets Recovery Account

The Regulatory Assets Recovery Account ["RARA"] consists of balances of regulatory assets or regulatory liabilities approved for disposition by the OEB through rate riders. The RARA is subject to carrying charges following the OEB prescribed methodology and related rates.

[all tabular amounts in thousands of Canadian dollars, unaudited]

On April 9, 2010, the OEB approved the disposition of net regulatory liabilities of $68,140,000, consisting of credit balances for settlement variances and income and other taxes variances of $58,225,000 and $11,900,000, respectively, and intangible assets debit balance of $1,985,000, over a two-year period commencing on May 1, 2010 and ending on April 30, 2012.

On October 29, 2010, the OEB approved the disposition of regulatory assets of $5,296,000, for amounts in connection with the contact voltage remediation activities, for the period commencing on November 1, 2010 and ending on April 30, 2012.

On February 22, 2011, the OEB approved the disposition of the Late Payment Penalties Settlement regulatory asset of $7,526,000, over a 21-month period commencing on August 1, 2011 and ending on April 30, 2013.

On July 7, 2011, the OEB approved the disposition of net regulatory liabilities of $8,572,000, consisting of credit balances for settlement variances, income and other taxes variances and 2008 RARA residual of $7,460,000, $3,373,000, and $789,000, respectively, and an International Financial Reporting Standards ["IFRS"] cost debit balance of $3,050,000, over a nine-month period commencing on August 1, 2011 and ending on April 30, 2012.

f) Income and Other Taxes Variance Account

The income and other taxes variance regulatory liability account relates to the differences that have resulted from a legislative or regulatory change to the tax rates or rules assumed in the rate adjustment model. As at March 31, 2012, the balance in this account consisted of an over-recovery from customers of $2,373,000 [December 31, 2011 - $2,365,000].

10. OTHER ASSETS

Other long-term assets consist of the following:

	March 31 2012 $	December 31 2011 $
Prepaid expenses	**7,270**	7,331
Debt issuance costs	**4,784**	5,092
	12,054	12,423

11. CREDIT FACILITIES

The Corporation is a party to a revolving credit facility expiring on May 3, 2013 ["Revolving Credit Facility"], pursuant to which the Corporation may borrow up to $400,000,000, of which up to $140,000,000 is available in the form of letters of credit. Additionally, the Corporation is a party to a bilateral facility for $50,000,000 for the purpose of issuing letters of credit mainly to support LDC's prudential requirements with the IESO.

As at March 31, 2012, no amounts had been drawn under the Corporation's Revolving Credit Facility [December 31, 2011 - $nil]. As at March 31, 2012, no amounts had been drawn for working capital purposes [December 31, 2011 - $nil].

As at March 31, 2012, $45,587,000 had been drawn on the bilateral facility [December 31, 2011 - $45,077,000].

[all tabular amounts in thousands of Canadian dollars, unaudited]

12. RESTRUCTURING

In the first quarter of 2012, the Corporation's Board of Directors approved a workforce restructuring program aimed at reducing its operating expenditures. The program was approved following the decision by the OEB to deny the request of LDC to set its electricity distribution rates for 2012, 2013 and 2014 under the COS framework. In preparing its application for electricity distribution rates for the 2012, 2013, and 2014 rate years using the IRM framework, including the filing of an ICM ["2012-2014 IRM/ICM Rate Application"], LDC concluded that significant cost reductions were necessary to manage its business within the confines of the expected allowed electricity distribution rates provided by the IRM framework *[note 3[a]]*. The main component of these operating cost reduction initiatives was a workforce restructuring program, which included the severance of management employees and a voluntary exit incentive program for targeted unionized positions.

For the three months ended March 31, 2012, the costs incurred as a result of these operating cost reduction initiatives amounted to approximately $27,796,000 and were comprised of ongoing termination payments to employees for $23,668,000 and one-time termination incentive payments to employees for $4,128,000, of which $24,662,000 remains unpaid as at March 31, 2012.

13. DEBENTURES

Debentures consist of the following:

	March 31 2012 $	December 31 2011 $
Senior unsecured debentures		
Series 1 – 6.11% due May 7, 2013	**224,980**	224,976
Series 2 – 5.15% due November 14, 2017	**249,841**	249,835
Series 3 – 4.49% due November 12, 2019	**249,952**	249,951
Series 5 – 6.11% due May 6, 2013	**245,057**	245,057
Series 6 – 5.54% due May 21, 2040	**199,858**	199,857
Series 7 – 3.54% due November 18, 2021	**299,854**	299,851
Total long-term portion of debentures	**1,469,542**	1,469,527

All debentures of the Corporation rank equally.

The Corporation may redeem some or all of the debentures at any time prior to maturity at a price equal to the greater of the Canada Yield Price (determined in accordance with the terms of the debentures) and par, plus accrued and unpaid interest up to but excluding the date fixed for redemption. Also, the Corporation may, at any time and from time to time, purchase debentures for cancellation, in the open market, by tender or by private contract, at any price. The debentures contain certain covenants which, subject to certain exceptions, restrict the ability of the Corporation and LDC to create security interests, incur additional indebtedness or dispose of all or substantially all of their assets.

[all tabular amounts in thousands of Canadian dollars, unaudited]

14. EMPLOYEE FUTURE BENEFITS

a) Pension

The Corporation provides a pension plan for its full time employees through OMERS. Details of the plan are as follows:

Pension Plan, Employer Identification Number / Pension Number	Funded Status as at December 31, 2011	Contributions Three months ended March 31	
		2012 $	2011 $
OMERS, 564191	89%	**5,185**	4,204

The Corporation's contributions do not represent more than five percent of total contributions to the plan as indicated in OMERS's most recently available annual report for the year ended December 31, 2011. As of the end of the year, no funding improvement plan or rehabilitation plan had been implemented or was pending.

For 2012, OMERS contribution rates are 8.3% up to the year's maximum pensionable earnings ["YMPE"] and 12.8% over YMPE for normal retirement age ["NRA"] of 65 [2011 - 7.4% up to YMPE and 10.7% over YMPE for NRA of 65].

b) Post-retirement benefits other than pension

The components of net periodic benefit cost are:

	Three months ended March 31	
	2012 $	2011 $
Service cost	**1,288**	977
Interest cost	**2,914**	2,877
Amortization of net actuarial loss	**762**	158
Amortization of prior service cost	**266**	273
Net periodic benefit cost	**5,230**	4,285
Capitalized as part of property, plant and equipment	**1,534**	1,544
Charged to operations	**3,696**	2,741

[all tabular amounts in thousands of Canadian dollars, unaudited]

15. ASSET RETIREMENT OBLIGATIONS

Reconciliation between the opening and closing ARO liability balances is as follows:

	March 31 2012 $	December 31 2011 $
Balance, beginning of period	**4,902**	5,005
ARO liabilities settled in the period	**(55)**	(688)
Accretion expense	**44**	173
Revision in estimated cash flows	**59**	412
Balance, end of period	**4,950**	4,902

16. FINANCIAL INSTRUMENTS

a) Recognition and measurement

The carrying value and fair value of the Corporation's financial instruments consist of the following:

	March 31 2012 $		December 31 2011 $	
	Carrying value	**Fair value [1]**	**Carrying value**	**Fair value [1]**
Cash and cash equivalents	**133,132**	**133,132**	154,256	154,256
Investments	**—**	**—**	34,002	34,002
Accounts receivable, net of allowance for doubtful accounts	**210,369**	**210,369**	183,272	183,272
Unbilled revenue	**243,890**	**243,890**	262,058	262,058
Accounts payable and accrued liabilities	**424,071**	**424,071**	412,412	412,412
Obligations under capital lease	**12,734**	**12,734**	13,172	13,172
Customers' advance deposits	**56,684**	**56,684**	56,038	56,038
Senior unsecured debentures				
Series 1 – 6.11% due May 7, 2013	**224,980**	**236,450**	224,976	238,359
Series 2 – 5.15% due November 14, 2017	**249,841**	**283,592**	249,835	284,126
Series 3 – 4.49% due November 12, 2019	**249,952**	**277,572**	249,951	275,575
Series 5 – 6.11% due May 6, 2013	**245,057**	**257,531**	245,057	259,578
Series 6 – 5.54% due May 21, 2040	**199,858**	**246,723**	199,857	245,096
Series 7 – 3.54% due November 18, 2021	**299,854**	**308,028**	299,851	306,696

[1] The fair value measurement of financial instruments recorded at amortized cost for which the fair value has been disclosed, including obligations under capital lease, are included in Level 2 of the fair value hierarchy.

[all tabular amounts in thousands of Canadian dollars, unaudited]

b) Risk Factors

The following is a discussion of risks and related mitigation strategies that have been identified by the Corporation for financial instruments. This is not an exhaustive list of all risks, nor will the mitigation strategies eliminate all risks listed.

The Corporation's activities provide for a variety of financial risks, particularly credit risk, interest rate risk and liquidity risk.

Credit risk

The Corporation is exposed to credit risk from financial instruments as a result of the risk of counterparties defaulting on their obligations. The Corporation monitors and limits its exposure to credit risk on a continuous basis.

The Corporation's credit risk associated with accounts receivable is primarily related to electricity bill payments from LDC customers. LDC has approximately 711,000 customers, the majority of which are residential. LDC collects security deposits from customers in accordance with direction provided by the OEB. As at March 31, 2012, LDC held security deposits in the amount of $56,684,000 [December 31, 2011 - $56,038,000].

Credit risk associated with accounts receivable is as follows:

	March 31 2012 $	December 31 2011 $
Total accounts receivable	**221,967**	196,259
Less: Allowance for doubtful accounts	**(11,598)**	(12,987)
Total accounts receivable, net	**210,369**	183,272
Of which:		
Outstanding for not more than 30 days	**179,322**	155,274
Outstanding for more than 30 days but not more than 120 days	**28,334**	24,777
Outstanding for more than 120 days	**14,311**	16,208
Less: Allowance for doubtful accounts	**(11,598)**	(12,987)
Total accounts receivable, net	**210,369**	183,272

Unbilled revenue represents amounts for which the Corporation has a contractual right to receive cash through future billings but are unbilled at period-end. As at March 31, 2012, total unbilled revenue was $243,890,000 [December 31, 2011 - $262,058,000]. Unbilled revenue is considered current.

As at March 31, 2012, there were no significant concentrations of credit risk with respect to any class of financial assets or counterparties. The Corporation's maximum exposure to credit risk is equal to the carrying value of its financial assets.

[all tabular amounts in thousands of Canadian dollars, unaudited]

Interest rate risk

The Corporation is exposed to interest rate risk through holding certain financial instruments, and short-term borrowings under the Corporation's Revolving Credit Facility *[note 11]* may expose the Corporation to fluctuations in short-term interest rates. The Corporation attempts to minimize interest rate risk by issuing long-term fixed rate debt, and by extending or shortening the term of its short-term money market investments by assessing the monetary policy stance of the Bank of Canada, while ensuring that all payment obligations are met on an ongoing basis.

Under an IRM framework, the Corporation's allowed return on equity will be fixed for all years that fall under the IRM period. Since the return on equity is fixed, a fluctuation of interest rates will not affect the return on equity and therefore will not require a hypothetical sensitivity analysis.

Liquidity risk

The Corporation is exposed to liquidity risk related to commitments associated with financial instruments. The Corporation monitors and manages its liquidity risk to ensure access to sufficient funds to meet operational and investing requirements. The Corporation's objective is to ensure that sufficient liquidity is on hand to meet obligations as they fall due while minimizing net financing charges. The Corporation has access to credit facilities and monitors cash balances daily to ensure that sufficient levels of liquidity are on hand to meet financial commitments as they come due. Liquidity risks associated with financial commitments are as follows:

March 31, 2012	Due within 1 year $	Due between 1 year and 5 years $	Due after 5 years $
Financial liabilities			
Accounts payable and accrued liabilities	**424,071**	**—**	**—**
Obligations under capital lease	**2,396**	**9,405**	**2,906**
Senior unsecured debentures			
Series 1 – 6.11% due May 7, 2013	**—**	**225,000**	**—**
Series 2 – 5.15% due November 14, 2017	**—**	**—**	**250,000**
Series 3 – 4.49% due November 12, 2019	**—**	**—**	**250,000**
Series 5 – 6.11% due May 6, 2013	**—**	**245,057**	**—**
Series 6 – 5.54% due May 21, 2040	**—**	**—**	**200,000**
Series 7 – 3.54% due November 18, 2021	**—**	**—**	**300,000**
Interest payments on debentures	**74,905**	**197,560**	**359,293**
	501,372	**677,022**	**1,362,199**

Hedging and Derivative risk

As at March 31, 2012 and December 31, 2011, the Corporation had not entered into hedging and derivative financial instruments.

Foreign exchange risk

As at March 31, 2012, the Corporation had limited exposure to the changing values of foreign currencies. While the Corporation purchases goods and services which are payable in US dollars, and purchases US currency to meet the related payables commitments when required, the impact of these transactions is not material to the interim consolidated financial statements.

[all tabular amounts in thousands of Canadian dollars, unaudited]

17. FINANCIAL GUARANTEES

The City has authorized the Corporation to provide financial assistance to its subsidiaries, and LDC to provide financial assistance to other subsidiaries of the Corporation, in the form of letters of credit and guarantees, for the purpose of enabling them to carry on their businesses up to an aggregate amount of $500,000,000.

18. INCOME TAXES

The Corporation's effective tax rate for the three months ended March 31, 2012 and March 31, 2011 was nil% and 8.41%, respectively. The effective tax rate for the three months ended March 31, 2012 and March 31, 2011 was lower than the 2012 and 2011 statutory income tax rates of 26.25% and 28.25% respectively, primarily due to recording deferred income taxes against regulatory assets and liabilities.

Income tax expense for the three months ended March 31, 2012 was $nil [three months ended March 31, 2011 - $2,338,000]. Income tax expense was lower for the three months ended March 31, 2012 compared to the three months ended March 31, 2011 primarily due to recording deferred income taxes against regulatory assets and liabilities.

19. SHARE CAPITAL

Share capital consists of the following:

	March 31 2012 $	**December 31 2011 $**
Authorized		
The authorized share capital of the Corporation consists of an unlimited number of common shares		
Issued and outstanding		
1,000 common shares	**567,817**	567,817

Dividends

The shareholder direction adopted by the City with respect to the Corporation provides that the Board of Directors of the Corporation will use its best efforts to ensure that the Corporation meets certain financial performance standards, including those relating to the credit rating and dividends.

Subject to applicable law, the shareholder direction provides that the Corporation will pay dividends to the City each year amounting to the greater of $25,000,000 or 50% of the Corporation's consolidated net income for the year. The dividends are not cumulative and are payable as follows:

[i] $6,000,000 on the last day of each of the first three fiscal quarters during the year;

[ii] $7,000,000 on the last day of the fiscal year; and

[all tabular amounts in thousands of Canadian dollars, unaudited]

[iii] the amount, if any, by which 50% of the Corporation's annual consolidated net income for the year exceeds $25,000,000, within ten days after the Board of Directors of the Corporation approved the Corporation's audited consolidated financial statements for the year.

On March 2, 2012, the Board of Directors of the Corporation declared dividends in the amount of $28,966,000. The dividends were comprised of $22,966,000 with respect to net income for the year ended December 31, 2011, which was paid to the City on March 12, 2012, and $6,000,000 with respect to the first quarter of 2012, was paid to the City on March 30, 2012 *[note 26[c]]*.

20. RELATED PARTIES

For the Corporation, transactions with related parties include transactions with the City. All transactions with the City are conducted at prevailing market prices and normal trade terms.

Transactions with Related Parties Summary	Three months ended March 31 2012 $	Three months ended March 31 2011 $
Revenues	**40,415**	42,016
Operating expenses and capital expenditures	**5,049**	4,949
Dividends	**28,966**	14,063

Transactions with Related Parties Summary	March 31 2012 $	December 31 2011 $
Accounts receivable, net of allowance for doubtful accounts	**6,829**	8,412
Unbilled revenue	**10,628**	9,363
Other assets	**7,257**	7,279
Accounts payable and accrued liabilities	**27,036**	25,085
Customers' advance deposits	**8,734**	8,714

Revenues represent amounts charged to the City primarily for electricity and street lighting services. Operating expenses and capital expenditures represent amounts charged by the City for purchased road cut repairs, property taxes and other services. Dividends represent dividends paid to the City.

Accounts receivable, net of allowance for doubtful accounts, represent receivables from the City primarily for street lighting, electricity and other services. Unbilled revenue represents receivables from the City related to the provision of electricity and street lighting services provided but not yet billed. Other assets represent amounts for prepaid land leases from the City. Accounts payable and accrued liabilities represent amounts payable to the City relating to road cut repairs, property taxes and other services, as well as funds received from the City for the construction of electricity distribution assets. Customers' advance deposits represent funds received from the City for future expansion projects.

[all tabular amounts in thousands of Canadian dollars, unaudited]

21. COMMITMENTS

Operating lease obligations and future commitments

As at March 31, 2012, the future minimum annual lease payments under property and equipment operating leases and future commitments with remaining terms from one to five years and thereafter were as follows:

	$
2012 [1]	**7,729**
2013	**23,614**
2014	**7,667**
2015	**6,656**
2016	**6,465**
Thereafter	**3,394**
Total amount of future minimum payments	**55,525**

[1] The amount disclosed represents the balance due over the period April 1, 2012 to December 31, 2012.

Capital lease obligations

As at March 31, 2012, the future minimum annual lease payments under capital leases with remaining lease terms from one to five years and thereafter were as follows:

	$
2012 [1]	**1,797**
2013	**2,394**
2014	**2,366**
2015	**2,337**
2016	**2,325**
Thereafter	**3,488**
Total amount of future minimum lease payments	**14,707**
Less: interest and executory costs	**1,973**
	12,734
Current portion included in Other liabilities	**1,781**
Long-term portion included in Other liabilities	**10,953**

[1] The amount disclosed represents the balance due over the period April 1, 2012 to December 31, 2012.

22. CONTINGENCIES

a) Legal Proceedings

In the ordinary course of business, the Corporation is subject to various litigation and claims with customers, suppliers, former employees and other parties. On an ongoing basis, the Corporation assesses the likelihood of any adverse judgments or outcomes as well as potential ranges of probable costs and losses. A determination of the provision required, if any, for these contingencies is made after an analysis of each individual issue. The provision may change in the future due to new developments in each matter or changes in approach, such as a change in settlement strategy. The Corporation and its subsidiaries are subject to various legal actions that arise in the normal course of business and if damages were awarded under these actions, the Corporation and its subsidiaries would make a claim under their liability insurance which the Corporation believes would cover any damages which may become payable by the Corporation and its subsidiaries in connection with these actions.

Christian Helm Class Action

On December 6, 2010, a statement of claim in a proposed class action was issued against LDC. The claim sought general and special damages in the amount of $100,000,000 for disgorgement of unjust gains allegedly resulting from the receipt of interest on overdue accounts in contravention of the *Interest Act* (Canada) *[note 26[b]]*.

2 Secord Avenue

An action was commenced against LDC in September 2008 in the Ontario Superior Court of Justice under the *Class Proceedings Act, 1992* (Ontario) ["Class Proceedings Act"] seeking damages in the amount of $30,000,000 as compensation for damages allegedly suffered as a result of a fire and explosion in an underground vault at 2 Secord Avenue on July 20, 2008. This action is at a preliminary stage. The statement of claim has been served on LDC, a statement of defence and third party claim have been served by LDC and a third party defence and counterclaim against LDC seeking damages in the amount of $51,000,000 have been filed. A certification order has been issued. Affidavits of documents have been produced by LDC to the other parties and examinations for discovery have commenced and are continuing. Given the preliminary status of this action, it is not possible to reasonably quantify the effect, if any, of this action on the financial performance of the Corporation. If damages were awarded, LDC would make a claim under its liability insurance which the Corporation believes would cover any damages which may become payable by LDC in connection with the action.

On December 20, 2010, LDC was served with a statement of claim by the City seeking damages in the amount of $2,000,000 as a result of the fire at 2 Secord Avenue. A statement of defence and a third party claim have been served. Given the preliminary status of this action, it is not possible to reasonably quantify the effect, if any, of this action on the financial performance of the Corporation. If damages were awarded, LDC would make a claim under its liability insurance which the Corporation believes would cover any damages which may become payable by LDC in connection with the action.

By order of the court, the above actions and a smaller non-class action commenced in April 2009 involving the same incident will be tried at the same time or consecutively.

2369 Lakeshore Boulevard West

A third party action was commenced against LDC in October 2009 in the Ontario Superior Court of Justice under the Class Proceedings Act seeking damages in the amount of $30,000,000 as compensation for damages allegedly suffered as a result of a fire in the electrical room at 2369 Lakeshore Boulevard West on March 19, 2009. Subsequently, in March 2010, the plaintiff in the main action amended its statement of claim to add LDC as a defendant. The plaintiff in the main action seeks damages in the amount of $10,000,000 from LDC. Both actions are at a preliminary stage and the certification hearing is scheduled for September 2012. Statements of defence to the main action and to the third party claim have not been filed. Accordingly, given the preliminary status of these actions, it is not possible at this time to reasonably quantify the effect, if any, of these actions on the financial performance of the Corporation. If damages were awarded, LDC would make a claim under its liability insurance which the Corporation believes would cover any damages which may become payable by LDC in connection with these actions.

Another third party action was commenced against LDC in October 2009 in the Ontario Superior Court of Justice seeking damages in the amount of $30,000,000 as compensation for damages allegedly suffered as a result of the fire at 2369 Lakeshore Boulevard West. Subsequently, in March 2010, the plaintiff in the main action amended its statement of claim to add LDC as a defendant. The plaintiff in the main action seeks damages in the amount of $400,000 from LDC. LDC has filed a statement of defence, crossclaim and counterclaim. Examinations for discovery have not taken place, notwithstanding a court ordered timetable to have them completed by February 29, 2012. Accordingly, given the preliminary status of these actions, it is not possible at this time to reasonably quantify the effect, if any, of these actions on the financial performance of the Corporation. If damages were awarded, LDC would make a claim under its liability insurance which the Corporation believes would cover any damages which may become payable by LDC in connection with these actions.

On August 29, 2011, LDC was served with a statement of claim by the owner of the building and the property management company for the building seeking damages in the amount of $2,000,000 as a result of the fire at 2369 Lakeshore Boulevard West. LDC has filed a statement of defence and counterclaim. Given the preliminary status of this action, it is not possible to reasonably quantify the effect, if any, of this action on the financial performance of the Corporation. If damages were awarded, LDC would make a claim under its liability insurance which the Corporation believes would cover any damages which may become payable by LDC in connection with the action.

b) OEB PILs Proceeding

The OEB conducted a review of the PILs variances accumulated in regulatory variance accounts for the period from October 1, 2001 to April 30, 2006 for certain Municipal Electricity Utilities ["MEUs"]. On June 24, 2011, the OEB issued its decision for these MEUs and provided guidelines for the calculation and further disposition of the balances accumulated in the PILs regulatory variance accounts. The OEB has issued interrogatories and decisions for other MEUs subsequent to its previous decision.

LDC has reviewed the balances of its PILs regulatory variance accounts and applied the guidelines provided by the OEB. As at March 31, 2012, LDC estimated its liability at approximately $6,615,000. This balance has been recorded in the Corporation's interim consolidated financial statements. LDC intends to apply for disposition of this balance in 2012 as part of its 2012-2014 IRM/ICM Rate Application. The amount to be approved by the OEB will be based on the OEB's interpretation and application of its guidelines and the final balance which is yet to be approved by the OEB could differ materially from LDC's estimation of its liability.

c) Payments in Lieu of Additional Municipal and School Taxes

The Ministry of Finance has issued assessments in respect of payments in lieu of additional municipal and school taxes under section 92 of the Electricity Act that are in excess of the amounts LDC believes are payable. The dispute arose as a result of inaccurate information incorporated into Ontario Regulation 224/00. The Corporation has worked with the Ministry of Finance to resolve this issue, and as a result the Ministry of Finance issued Ontario Regulation 423/11 on August 31, 2011. The new regulation revoked Ontario Regulation 224/00 and corrected inaccurate information retroactively to 1999.

The balance assessed by the Ministry of Finance on its most recent statement of account amounts to approximately $10,043,000 above the balance accrued by the Corporation [December 31, 2011 - $10,043,000]. While the Corporation expects that reassessments will be issued as a consequence of the change in regulation, there can be no assurance that the Corporation will not have to pay the full assessed balance in the future.

23. NET INCOME (LOSS) PER SHARE

The weighted daily average number of shares outstanding for the three months ended March 31, 2012 was 1,000 [three months ended March 31, 2011 - 1,000]. Basic and fully diluted net income (loss) per share was determined by dividing the net income (loss) for the period by the weighted daily average number of shares outstanding.

24. US GAAP TRANSITION

Publicly accountable enterprises in Canada were required to adopt IFRS in place of Canadian GAAP for interim and annual reporting purposes for fiscal years beginning on or after January 1, 2011. In the absence of a definitive plan to consider the issuance of a RRA standard by the International Accounting Standards Board, the Corporation decided to evaluate the option of adopting US GAAP effective January 1, 2012 as an alternative to IFRS. On August 26, 2011, the Board of Directors of the Corporation approved the adoption of US GAAP for financial reporting purposes for the year beginning on January 1, 2012.

These are the Corporation's first interim consolidated financial statements prepared in accordance with US GAAP. The accounting policies set out in note 4 have been applied consistently in preparing the interim consolidated financial statements for the three months ended March 31, 2012 and the comparative periods.

The Corporation has adjusted amounts reported previously in its interim and annual consolidated financial statements prepared in accordance with Canadian GAAP. For reporting purposes, the transition date to US GAAP is January 1, 2011, which is the commencement of the 2011 interim comparative period to the Corporation's 2012 interim consolidated financial statements. An explanation of how the transition from Canadian GAAP to US GAAP has affected the Corporation's interim consolidated financial statements is set out in the following tables and accompanying notes.

The reconciliation of the January 1, 2011 consolidated balance sheet from Canadian GAAP to US GAAP is as follows:

CONSOLIDATED BALANCE SHEET

[in thousands of Canadian dollars]

As at January 1, 2011	Notes	Canadian GAAP $	Transitional Adjustments $	US GAAP $
ASSETS				
Current				
Regulatory assets	A	—	3,555	**3,555**
Other	B	805,310	718	**806,028**
Total current assets		805,310	4,273	**809,583**
Regulatory assets	A	85,113	29,224	**114,337**
Other	B	2,448,191	4,132	**2,452,323**
Total assets		3,338,614	37,629	**3,376,243**
LIABILITIES AND SHAREHOLDER'S EQUITY				
Current				
Customers' advance deposits	C	—	50,630	**50,630**
Post-retirement benefits	A	—	7,415	**7,415**
Regulatory liabilities	A	—	36,654	**36,654**
Other	C	639,751	(18,790)	**620,961**
Total current liabilities		639,751	75,909	**715,660**
Customers' advance deposits	C	45,462	(31,840)	**13,622**
Debentures	B	1,164,780	4,850	**1,169,630**
Post-retirement benefits	A	169,897	22,715	**192,612**
Regulatory liabilities	A	273,706	(34,005)	**239,701**
Other		5,639	—	**5,639**
Total liabilities		2,299,235	37,629	**2,336,864**
Total shareholder's equity		1,039,379	—	**1,039,379**
Total liabilities and shareholder's equity		3,338,614	37,629	**3,376,243**

The reconciliation of the December 31, 2011 consolidated balance sheet from Canadian GAAP to US GAAP is as follows:

CONSOLIDATED BALANCE SHEET

[in thousands of Canadian dollars]

As at December 31, 2011	Notes	Canadian GAAP $	Transitional Adjustments $	US GAAP $
ASSETS				
Current				
Other	B	656,278	922	**657,200**
Total current assets		656,278	922	**657,200**
Regulatory assets	A	77,322	65,716	**143,038**
Other	B	2,722,177	5,092	**2,727,269**
Total assets		3,455,777	71,730	**3,527,507**
LIABILITIES AND SHAREHOLDER’S EQUITY				
Current				
Customers’ advance deposits	C	—	40,238	**40,238**
Post-retirement benefits	A	—	7,915	**7,915**
Regulatory liabilities	A	—	7,293	**7,293**
Other	C	448,061	(20,108)	**427,953**
Total current liabilities		448,061	35,338	**483,399**
Customers’ advance deposits	C	35,930	(20,130)	**15,800**
Debentures	B	1,463,514	6,013	**1,469,527**
Post-retirement benefits	A	179,541	56,870	**236,411**
Regulatory liabilities	A	210,280	(6,361)	**203,919**
Other		16,203	—	**16,203**
Total liabilities		2,353,529	71,730	**2,425,259**
Total shareholder’s equity		1,102,248	—	**1,102,248**
Total liabilities and shareholder’s equity		3,455,777	71,730	**3,527,507**

The reconciliation of net income from Canadian GAAP to US GAAP for the three months ended March 31, 2011 is as follows:

RECONCILIATION OF NET INCOME FROM CANADIAN GAAP TO US GAAP

[in thousands of Canadian dollars]

Three months ended March 31, 2011	**Notes**	**$**
Net income, Canadian GAAP		25,452
Revenues	D	2,846
Purchased power and other	D	446
Operating expenses	D	(3,292)
Net income, US GAAP		**25,452**

Notes to the transitional adjustments

A. Post-retirement benefits

Under Canadian GAAP, unamortized actuarial gains and losses and unamortized prior service costs are not recorded on the consolidated balance sheet. Under US GAAP, all actuarial gains and losses and prior service costs are fully recognized in OCI in the period in which they arise and are presented within equity as Accumulated Other Comprehensive Income ["AOCI"]. Due to the rate-regulated nature of the Corporation's business, the impact to AOCI on transition and the impact to OCI on a go-forward basis will be reclassified to a regulatory asset account *[note 9[b]]*. This reclassification results in the full recognition of the benefit obligation as a liability on the Corporation's consolidated balance sheets and no balance reported in OCI and AOCI. A portion of the benefit obligation will also be presented as a current liability on the consolidated balance sheets. The current portion is the amount by which the actuarial present value of benefits included in the benefit obligation is payable in the next 12 months.

B. Debt issuance costs

Under Canadian GAAP, debt issuance costs are netted against the principal balance of the related debenture. Under US GAAP, debt issuance costs are recognized as deferred charges. This presentation difference results in an increase in other current assets and other assets and an offsetting increase to debentures.

C. Customers' advance deposits

Under US GAAP, deposits that are due on demand or will be due on demand within one year from the end of the reporting period have been reclassified as current liabilities.

D. Demand billable income and expenses

Under US GAAP, demand billable income and the associated costs have been reclassified on the consolidated statements of operations and comprehensive income (loss). There is no impact to the overall net income.

25. SEASONAL OPERATIONS

The Corporation's quarterly results are impacted by changes in revenues resulting from variations in seasonal weather conditions, the fluctuations in electricity prices, and the timing and recognition of regulatory decisions. The Corporation's revenues tend to be higher in the first and third quarters of a year as a result of higher energy consumption for winter heating in the first quarter and air conditioning/cooling in the third quarter.

26. SUBSEQUENT EVENTS

The Corporation has evaluated the events and transactions occurring after the consolidated balance sheet date through May 17, 2012 when the Corporation's interim consolidated financial statements were available to be issued after the approval by the Corporation's Board of Directors, and identified the following events and transactions which required recognition in the interim consolidated financial statements and/or disclosure in the notes to the interim consolidated financial statements:

a) Electricity Distribution Rates

On May 10, 2012, LDC filed the 2012-2014 IRM/ICM Rate Application *[note 3[a]]*. The formulaic adjustment, requested by LDC, follows the guidelines provided by the OEB and seeks to increase the current revenue requirement by 0.68% to $525,500,000 for 2012, $529,100,000 for 2013 and $532,700,000 for 2014. The 2013 and 2014 formulaic adjustment may be subject to change depending on future inflation and market data.

The ICM proposed by LDC establishes rate riders allowing for the recovery of capital spending of $275,700,000 in 2012, $361,500,000 in 2013 and $266,500,000 in 2014 in excess of the OEB's threshold amounts. The calculation of the related requested rate riders was derived using guidelines provided by the OEB. Accordingly, when factoring the amount of capital currently included in LDC's electricity distribution rates, the total amount of capital requested amounts to $448,700,000 in 2012, $534,500,000 in 2013 and $439,500,000 in 2014.

The 2012-2014 IRM/ICM Rate Application is expected to be subject to an in-depth review by the OEB over the next few months. There can be no assurance that the OEB will allow for the total or partial recovery of the capital expenditure balances requested in the 2012-2014 IRM/ICM Rate Application. The outcome of the 2012-2014 IRM/ICM Rate Application could have a material impact on the Corporation's consolidated financial statements in the future.

b) Christian Helm Class Action

On April 30, 2012, a settlement reached by the parties was approved by Order of the Ontario Superior Court of Justice. Pursuant to the terms of the Order, LDC will pay the amount of $5,836,000 plus costs in settlement of all claims, the action has been dismissed, and the claims by all class members have been released. The Corporation accrued a liability to cover the expected settlement in 2010 *[note 22[a]]*.

c) Dividends

On May 17, 2012, the Board of Directors of the Corporation declared a dividend in the amount of $6,000,000 with respect to the second quarter of 2012. The dividend is payable on June 29, 2012 *[note 19]*.

MANAGEMENT'S DISCUSSION AND ANALYSIS
MARCH 31, 2012

TORONTO HYDRO CORPORATION

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS FOR THE INTERIM PERIOD ENDED MARCH 31, 2012

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Forward-Looking Information

Toronto Hydro Corporation (the "Corporation") includes forward-looking information in its Management's Discussion and Analysis ("MD&A") within the meaning of applicable securities laws in Canada ("forward-looking information"). The purpose of the forward-looking information is to provide management's expectations regarding the Corporation's future results of operations, performance, business prospects and opportunities and may not be appropriate for other purposes. All forward-looking information is given pursuant to the "safe harbour" provisions of applicable Canadian securities legislation. The words "anticipates", "believes", "budgets", "could", "estimates", "expects", "forecasts", "intends", "may", "might", "plans", "projects", "schedule", "should", "will", "would" and similar expressions are often intended to identify forward-looking information, although not all forward-looking information contains these identifying words. The forward-looking information reflects management's current beliefs and is based on information currently available to the Corporation's management.

The forward-looking information in the MD&A includes, but is not limited to, statements regarding Toronto Hydro-Electric System Limited's ("LDC") distribution revenue, the outcome of outstanding rate applications and other proceedings before the Ontario Energy Board ("OEB"), the Corporation's plans to borrow funds to repay maturing debentures and to finance the investment in LDC's infrastructure, LDC's Conservation and Demand Management ("CDM") programs, the outcome of outstanding proceedings before the Ministry of Finance of Ontario ("Ministry of Finance"), the expected results of legal proceedings, market volatility on the Corporation's consolidated results of operations, performance, business prospects and opportunities, the effect of changes in interest rates on future revenue requirements and the changes in accounting estimates. The statements that make up the forward-looking information are based on assumptions that include, but are not limited to, the future course of the economy and financial markets, the receipt of applicable regulatory approvals and requested rate orders, the receipt of favourable judgments, the level of interest rates and the Corporation's ability to borrow.

The forward-looking information is subject to risks, uncertainties and other factors that could cause actual results to differ materially from historical results or results anticipated by the forward-looking information. The factors which could cause results or events to differ from current expectations include, but are not limited to, market liquidity and the quality of the underlying assets and financial instruments, the timing and extent of changes in prevailing interest rates, inflation levels, legislative, judicial and regulatory developments that could affect revenues and the results of borrowing efforts.

All forward-looking information in the MD&A is qualified in its entirety by the above cautionary statements and, except as required by law, the Corporation undertakes no obligation to revise or update any forward-looking information as a result of new information, future events or otherwise after the date hereof.

Introduction

The following MD&A should be read in conjunction with:

- the unaudited interim consolidated financial statements and accompanying notes of the Corporation as at and for the three-month period ended March 31, 2012 (the "Interim Consolidated Financial Statements");

- the audited consolidated financial statements and accompanying notes of the Corporation as at and for the year ended December 31, 2011 (the "Annual Consolidated Financial Statements"); and

- the Corporation's MD&A for the year ended December 31, 2011 (including the sections entitled "Electricity Distribution – Industry Overview", "Summary of Quarterly Results", "Liquidity and Capital Resources", "Corporate Developments", "Legal Proceedings", "Share Capital", "Transactions with Related Parties", "Risk Factors", "Critical Accounting Estimates", "Changes in Accounting Estimates", and "Future Accounting Pronouncements" which remain substantially unchanged as at the date hereof except as noted below or as updated by the Interim Consolidated Financial Statements).

Copies of these documents are available on the Canadian Securities Administrators' web site at www.sedar.com.

Effective January 1, 2012, the Corporation's Interim Consolidated Financial Statements have been prepared in accordance with United States Generally Accepted Accounting Principles ("US GAAP"), including the accounting principles prescribed by the OEB in the "Accounting Procedures Handbook for Electricity Distributors" (the "AP Handbook") and are presented in Canadian dollars (see "Significant Accounting Policies" below). The Corporation's Annual and Interim Consolidated Financial Statements were prepared in accordance with Canadian Generally Accepted Accounting Principles ("Canadian GAAP") until December 31, 2011. All comparative consolidated financial statements have been adjusted from the consolidated financial statements previously presented to conform to the presentation of the Corporation's first interim 2012 consolidated financial statements prepared in accordance with US GAAP, retroactively.

Business of Toronto Hydro Corporation

The Corporation is a holding company which wholly-owns two subsidiaries:

- *LDC* - which distributes electricity and engages in CDM activities; and

- *Toronto Hydro Energy Services Inc.* ("TH Energy") - which provides street lighting services.

The principal business of the Corporation and its subsidiaries is the distribution of electricity by LDC. LDC owns and operates an electricity distribution system, which delivers electricity to approximately 711,000 customers located in the City of Toronto (the "City"). LDC is the largest municipal electricity distribution company in Canada and distributes approximately 18% of the electricity consumed in the Province of Ontario ("Ontario"). The business of LDC is regulated by the OEB which has broad powers relating to licensing, standards of conduct and service and the regulation of electricity distribution rates charged by LDC and other electricity distributors in Ontario. See note 2 to the Annual Consolidated Financial Statements.

The sole shareholder of the Corporation is the City.

Executive Summary

- Net loss for the three months ended March 31, 2012 was $12.8 million compared to a net income of $25.5 million for the comparable period in 2011;
- capital expenditures were $65.4 million for the three months ended March 31, 2012 compared to $100.3 million for the comparable period in 2011, with the decrease primarily related to lower capital expenditures currently included in the electricity distribution rates of LDC for 2012;
- on May 10, 2012, LDC filed its application to set electricity distribution rates for the 2012, 2013 and 2014 rate years under the Incentive Regulation Mechanism ("IRM") framework; and
- effective January 1, 2012, the Corporation's Interim Consolidated Financial Statements have been prepared in accordance with US GAAP.

Selected Interim Consolidated Financial Data

Interim Consolidated Statements of Operations and Comprehensive Income (Loss)
Three months ended March 31
(in thousands of Canadian dollars, except for per share amounts, unaudited)

	2012 $	2011 $	Change $	Change %
Revenues	699,660	704,188	(4,528)	(0.6)
Costs				
Purchased power	562,430	560,819	1,611	0.3
Operating expenses	68,182	66,175	2,007	3.0
Depreciation and amortization	35,428	33,472	1,956	5.8
	666,040	660,466	5,574	0.8
Income before the following:	33,620	43,722	(10,102)	(23.1)
Net financing charges	(18,650)	(18,896)	246	1.3
Gain on disposals of property, plant and equipment ("PP&E")	-	2,964	(2,964)	(100.0)
Restructuring costs	(27,796)	-	(27,796)	(100.0)
Income (loss) before income taxes	(12,826)	27,790	(40,616)	(146.2)
Income tax expense	-	2,338	(2,338)	(100.0)
Net income (loss) and comprehensive income (loss)	(12,826)	25,452	(38,278)	(150.4)
Basic and fully diluted net income (loss) per share	(12,826)	25,452	(38,278)	(150.4)

Interim Consolidated Balance Sheets Data (in thousands of Canadian dollars, unaudited)		
	As at March 31 2012 $	**As at December 31 2011 $**
Total assets	3,520,889	3,527,507
Current liabilities	516,023	483,399
Long-term liabilities	1,944,410	1,941,860
Total liabilities	2,460,433	2,425,259
Shareholder’s equity	1,060,456	1,102,248
Total liabilities and shareholder’s equity	3,520,889	3,527,507

Results of Operations

Net Income (Loss)

Net loss for the three months ended March 31, 2012 was $12.8 million compared to net income of $25.5 million for the comparable period in 2011. The decrease in net income for the three months ended March 31, 2012 was primarily due to restructuring costs incurred in conjunction with cost reduction initiatives at LDC in the first quarter of 2012 (see “Results of Operations – Restructuring Costs” below) ($27.8 million), lower net revenues ($6.1 million), lower gain on disposals of PP&E ($3.0 million), higher operating expenses ($2.0 million) and higher depreciation expense ($2.0 million). These unfavourable variances were partially offset by lower income tax expense ($2.3 million).

Net Revenues

Net revenues for the three months ended March 31, 2012 were $137.2 million compared to $143.4 million for the comparable period in 2011 (see “Non-GAAP Financial Measures” below). The decrease in net revenues for the three months ended March 31, 2012 was primarily due to lower regulated distribution revenue at LDC ($6.1 million). The decrease in distribution revenue was primarily due to an adjustment recorded in 2012 for future taxes payable to customers ($4.6 million) and lower consumption in 2012 (6,358 Gigawatt-Hours (“GWh”) in 2012 compared to 6,642 GWh in 2011) ($3.6 million), partially offset by the approval by the OEB of higher revenue requirement balance for the first three months of 2012 compared to the first three months of 2011 ($1.8 million) (see “Corporate Developments – Distribution Rates for LDC” below).

Expenses

Operating expenses for the three months ended March 31, 2012 were $68.2 million compared to $66.2 million for the comparable period in 2011. The increase in operating expenses for the three months ended March 31, 2012 was primarily due to higher overall compensation costs due to annual general increase in wages and related benefits ($3.5 million), partially offset by a decrease in the provision relating to legal proceedings ($1.4 million).

Depreciation and amortization expense for the three months ended March 31, 2012 was $35.4 million compared to $33.5 million for the comparable period in 2011. The increase in depreciation and amortization expense for the three months ended March 31, 2012 was primarily due to the depreciation of assets capitalized during the last three quarters of 2011 in relation to the renewal of the regulated electricity distribution infrastructure of LDC.

Gain on Disposals of PP&E

Gain on disposals of PP&E for the three months ended March 31, 2012 was $nil compared to $3.0 million for the comparable period in 2011. The decrease in gain on disposals of PP&E was primarily due to the recognition of gains realized in connection with the disposals of surplus properties at LDC in 2011.

Restructuring Costs

In the first quarter of 2012, the Corporation's Board of Directors approved a workforce restructuring program aimed at reducing its operating expenditures. The program was approved following the decision by the OEB to deny the request of LDC to set its electricity distribution rates for 2012, 2013, and 2014 under the Cost of Service ("COS") framework. In preparing its application for electricity distribution rates for the 2012, 2013 and 2014 rate years using the IRM framework, including the filing of an Incremental Capital Module ("ICM") ("2012-2014 IRM/ICM Rate Application"), LDC concluded that significant cost reductions were necessary to manage its business within the confines of the expected allowed electricity distribution rates provided by the IRM framework. The main component of these operating cost reduction initiatives was a workforce restructuring program, which included the severance of management employees and a voluntary exit incentive program for targeted unionized positions. See "Corporate Developments – Distribution Rates for LDC" below.

Restructuring costs for the three months ended March 31, 2012 were $27.8 million compared to $nil for the comparable period in 2011. This balance is comprised of ongoing termination payments to employees for $23.7 million and one-time termination incentive payments to employees for $4.1 million, of which $24.7 million remains unpaid as at March 31, 2012.

Income Tax Expense

Income tax expense for the three months ended March 31, 2012 was $nil compared to $2.3 million for the comparable period in 2011. The decrease in the income tax expense for the three months ended March 31, 2012 was primarily due to lower earnings before taxes ($10.7 million) offset by lower deductions for permanent and temporary differences between accounting and tax treatments ($8.4 million).

Quarterly Results of Operations

The table below presents unaudited quarterly consolidated financial information of the Corporation for the eight quarters including and immediately preceding March 31, 2012.

Quarterly Results of Operations
(in thousands of Canadian dollars, unaudited)

	March 31 2012 $	December 31 2011 $	September 30 2011 $	June 30 2011 $
Revenues	699,660	694,284	738,352	686,646
Costs	666,040	653,374	687,280	648,684
Net income (loss).........................	(12,826)	17,228	28,982	24,270
	March 31 2011 $	**December 31 2010 $**	**September 30 2010 $**	**June 30 2010 $**
Revenues	704,188	659,043	683,376	630,283
Costs	660,466	623,573	634,679	593,087
Net income	25,452	10,048	27,687	15,839

The Corporation's quarterly results are impacted by changes in revenues resulting from variations in seasonal weather conditions, the fluctuations in electricity prices, and the timing and recognition of regulatory decisions. The Corporation’s revenues tend to be higher in the first and third quarters of a year as a result of higher energy consumption for winter heating in the first quarter and air conditioning and cooling in the third quarter.

Financial Position

The following table outlines the significant changes in the consolidated balance sheets between March 31, 2012 and December 31, 2011.

Interim Consolidated Balance Sheets Data
As at March 31, 2012 compared to December 31, 2011
(in thousands of Canadian dollars, unaudited)

Balance Sheet Account	Increase (Decrease) $	Explanation of Significant Change
Cash and cash equivalents....................	(21,124)	See “Liquidity and Capital Resources” below.
Investments...	(34,002)	The decrease in investments is due to the sale and maturity of two floating rate notes in the amounts of $25.0 million and $9.0 million, the first was sold on February 15, 2012 and the second matured on February 17, 2012.
Accounts receivable, net of allowance for doubtful accounts...........	27,097	The increase in accounts receivable is primarily due to the timing of billing and collection activities from large customers.
Unbilled revenue	(18,168)	The decrease in unbilled revenue is primarily due to lower consumption in March 2012 compared to December 2011, which is partially offset by higher energy prices compared to the previous period.
PP&E and intangible assets, net	29,601	The increase in PP&E and intangible assets is primarily due to capital expenditures ($65.4 million) offset by depreciation during the year ($35.4 million).
Regulatory assets.................................	10,767	The increase in regulatory assets is primarily due to increases in the retail settlement balances regulated by the OEB partially offset by the on-going recoveries of charges from customers.
Deferred income tax assets..................	(4,880)	The decrease in deferred income tax assets is primarily due to a decrease in the deductible temporary differences between tax and accounting values of PP&E.
Accounts payable and accrued liabilities...	11,659	The increase in accounts payable and accrued liabilities is mainly due to timing differences in the settlement of interest on the debentures.
Restructuring accrual............................	24,662	The restructuring accrual is primarily due to the workforce restructuring program initiated by the Corporation in the first quarter of 2012 (see “Results of Operations – Restructuring Costs” above).

Interim Consolidated Balance Sheets Data As at March 31, 2012 compared to December 31, 2011 (in thousands of Canadian dollars, unaudited)		
Balance Sheet Account	**Increase (Decrease) $**	**Explanation of Significant Change**
Deferred revenue	8,472	The increase in deferred revenue is primarily due to a balance received in advance from the OPA relating to CDM programs and the receipt of annual pole and duct rental fees for 2012.
Regulatory liabilities	(11,962)	The decrease in regulatory liabilities is primarily due to the net disposition of retail settlement balances to customers approved by the OEB and a reduction of deferred income tax assets payable to customers.
Retained earnings	(41,792)	The decrease in retained earnings is due to dividends paid ($29.0 million) and the net loss during the period ($12.8 million).

Liquidity and Capital Resources

Sources of Liquidity and Capital Resources

The Corporation's primary sources of liquidity and capital resources are cash provided by operating activities, bank financing, interest income and borrowings from debt capital markets. The Corporation's liquidity and capital resource requirements are mainly for capital expenditures to maintain and improve the electricity distribution system of LDC, to purchase power, to meet financing charges and for prudential requirements.

The Corporation does not believe that equity contributions from the City, its sole shareholder, will constitute a source of capital.

Liquidity and Capital Resources Three months ended March 31 (in thousands of Canadian dollars, unaudited)		
	2012 $	**2011 $**
Cash and cash equivalents, beginning of period	154,256	330,151
Net cash provided by operating activities	55,934	45,329
Net cash used in investing activities	(48,738)	(158,516)
Net cash used in financing activities	(28,320)	(20,869)
Cash and cash equivalents, end of period	133,132	196,095

Net Cash Provided by Operating Activities

Net cash provided by operating activities for the three months ended March 31, 2012 was $55.9 million compared to $45.3 million for the comparable period in 2011. The increase in net cash provided by operating activities for the three months ended March 31, 2012 was primarily due to a variance in the aggregate amount of accounts receivable and unbilled revenue due to the timing of billing and collection activities ($43.8 million), the recognition of a restructuring accrual (see "Results of Operations – Restructuring Costs" above) ($24.7 million) and an increase in deferred revenue relating to cash received in advance from the OPA for CDM programs in 2012 ($6.3 million). These variances were partially offset by a decrease in net income ($38.3 million) and a decrease in accounts payable and accrued liabilities primarily due to timing of payments to suppliers ($22.1 million).

Net Cash Used in Investing Activities

Net cash used in investing activities for the three months ended March 31, 2012 was $48.7 million compared to $158.5 million for the comparable period in 2011. The decrease in net cash used in investing activities for the three months ended March 31, 2012 was primarily due to the purchase of investments in 2011 ($50.0 million), lower capital expenditures in 2012 ($35.0 million), and the net proceeds received from the sale of investments in 2012 ($34.0 million). These variances were partially offset by a higher change in net regulatory assets and liabilities ($7.6 million) primarily related to a higher variance in 2012 of retail settlement balances regulated by the OEB and the impact of the net proceeds received in 2011 on the disposition of surplus properties ($1.7 million).

The following table summarizes the Corporation's capital expenditures for the periods indicated.

Capital Expenditures
Three months ended March 31
(in thousands of Canadian dollars, unaudited)

	2012 $	2011 $
LDC		
Distribution system	59,591	86,879
Technology assets	4,142	5,871
Other [(1)]	1,327	5,782
	65,060	98,532
Other [(2)]	318	1,816
Total Capital Expenditures	65,378	100,348

Notes:

(1) Consists of leasehold improvements, vehicles, other work-related equipment, furniture and office equipment.
(2) Includes unregulated capital expenditures primarily related to TH Energy.

Under the current electricity distribution rates, the OEB-approved regulated capital expenditures amounted to approximately $140.0 million. For 2011, the OEB approved $378.8 million in regulated capital expenditures for LDC. On May 10, 2012, LDC filed its 2012-2014 IRM/ICM Rate Application with the OEB seeking funding for total regulated capital expenditures of $448.7 million in 2012, $534.5 million in 2013 and $439.5 million in 2014 (see "Corporate Developments – Distribution Rates for LDC" below).

The decrease in regulated capital expenditures at LDC for the three months ended March 31, 2012 amounted to $33.5 million and was primarily due to the uncertainty surrounding LDC's capital work program as a result of the OEB's decision to disallow LDC's COS application for the 2012, 2013 and 2014 rate years. This decrease was mainly within distribution lines ($22.8 million), other fleet and equipment ($3.8 million), metering ($3.7 million), switchgears ($3.3 million), customer connections ($2.0 million), and feeders ($1.8 million). These decreases were partially offset by an increase of capital expenditures in stations ($5.9 million).

The three most significant areas for regulated capital expenditures incurred by LDC in the current period were related to maintaining the reliability of the electricity distribution system, primarily by replacing aging assets ($24.5 million), upgrading and investing in stations ($18.5 million), and net expenditures related to customer connections primarily due to the growth in the condominium market ($5.3 million).

Net Cash Used in Financing Activities

Net cash used in financing activities for the three months ended March 31, 2012 was $28.3 million compared to $20.9 million for the comparable period in 2011. The increase in net cash used in financing activities was primarily due to a higher dividend paid with respect to net income for the year ended December 31, 2011, which was paid to the City on March 12, 2012 ($14.9 million), partially offset by an increase in customer deposits in 2012 in compliance with OEB rules and regulations ($7.5 million).

Summary of Contractual Obligations and Other Commitments

The following table presents a summary of the Corporation's debentures, major contractual obligations and other commitments.

Summary of Contractual Obligations and Other Commitments
As at March 31, 2012
(in thousands of Canadian dollars, unaudited)

	Total $	2012[1] $	2013/2014 $	2015/2016 $	After 2016 $
Debentures – principal repayment...	1,470,057	–	470,057	–	1,000,000
Debentures – interest payments.......	631,758	74,905	105,960	91,600	359,293
Operating lease obligations and future commitments........................	55,525	7,729	31,281	13,121	3,394
Capital lease obligations …............	14,707	1,797	4,760	4,662	3,488
Asset retirement obligations...........	5,839	1,371	458	241	3,769
Total contractual obligations and other commitments….....................	2,177,886	85,802	612,516	109,624	1,369,944

Notes:

(1) The amounts disclosed represent the balances due over the period April 1, 2012 to December 31, 2012.

Revolving Credit Facility

The Corporation is a party to a revolving credit facility expiring on May 3, 2013, pursuant to which the Corporation may borrow up to $400.0 million, of which up to $140.0 million is available in the form of letters of credit. Additionally, the Corporation is a party to a bilateral facility for $50.0 million for the purpose of issuing letters of credit mainly to support LDC's prudential requirements with the IESO.

As at March 31, 2012, no amounts had been drawn under the Corporation's revolving credit facility and $45.6 million had been drawn on the bilateral facility.

Prudential Requirements and Third Party Credit Support

The City has authorized the Corporation to provide financial assistance to its subsidiaries, and LDC to provide financial assistance to other subsidiaries of the Corporation, in the form of letters of credit and guarantees, for the purpose of enabling them to carry on their businesses up to an aggregate amount of $500.0 million.

Dividends

On March 2, 2012, the Board of Directors of the Corporation declared dividends in the amount of $29.0 million. The dividends were comprised of $23.0 million with respect to net income for the year ended December 31, 2011, which was paid to the City on March 12, 2012, and $6.0 million with respect to the first quarter of 2012, which was paid to the City on March 30, 2012.

On May 17, 2012, the Board of Directors of the Corporation declared a dividend in the amount of $6.0 million with respect to the second quarter of 2012. The dividend is payable on June 29, 2012.

Credit Ratings

The Corporation and the debentures issued under its medium-term note program were rated as follows:

Credit Ratings As at March 31, 2012	
DBRS Limited	A (high)
Standard & Poor's	A

Corporate Developments

Distribution Rates for LDC

Regulatory developments in Ontario's electricity industry, including current and possible future consultations between the OEB and interested stakeholders, may affect LDC's electricity distribution rates and other permitted recoveries in the future. LDC's electricity distribution rates are typically effective from May 1 to April 30 of the following year. Accordingly, for the first three months of 2012, distribution revenue was based on electricity distribution rates approved for the May 1, 2011 to April 30, 2012 rate year (the "2011 Rate Year").

LDC's electricity distribution rates for the 2011 Rate Year were determined through an application under the COS framework. The COS framework sets electricity distribution rates using a detailed examination of evidence and an assessment of the costs incurred by an electricity distributor to provide its service to its customers.

On July 7, 2011, the OEB issued its decision regarding LDC's electricity distribution rates for the 2011 Rate Year. The decision provided for a distribution revenue requirement and rate base of $522.0 million and $2,298.2 million, respectively. In addition, the decision provided for capital program spending levels and operating, maintenance and administration spending levels of $378.8 million and $238.0 million, respectively.

On August 26, 2011, LDC filed a rate application, following the COS framework, with the OEB seeking approval of separate and successive revenue requirements and corresponding electricity distribution rates for three rate years commencing on May 1, 2012, May 1, 2013 and May 1, 2014 (the "2012-2014 Rate Application"). The requested distribution revenue requirements for these rate years were $571.4 million, $639.5 million, and $712.8 million, respectively, and the expected rate bases for these rate years were $2,636.3 million, $3,053.5 million, and $3,503.2 million, respectively.

Pursuant to the IRM framework, the OEB established, as a preliminary issue in the 2012-2014 Rate Application, that it would consider the question of whether the application filed by LDC under the COS framework was acceptable or whether it should be dismissed. The IRM framework provides for an adjustment to an electricity distributor's rates based on a formulaic calculation with the possibility to request an ICM to address specific capital expenditure needs not covered by the formulaic calculation. The review of an ICM application is done by the OEB following defined criteria, such as materiality, causation and prudence.

LDC filed evidence supporting its position for electricity distribution rates to be set under the COS framework as part of its 2012-2014 Rate Application. The OEB established a process by which a portion of LDC's evidence was tested during an oral hearing held in November 2011.

On January 5, 2012, the OEB rendered its decision on the preliminary issue and dismissed LDC's COS framework 2012-2014 Rate Application. In its decision, the OEB found that LDC was not permitted to deviate from the standard IRM framework cycle. Accordingly, LDC was required to file its request for electricity distribution rates commencing on May 1, 2012 pursuant to the IRM framework and to use the ICM to request the capital needed for infrastructure renewal.

On January 25, 2012, LDC filed with the OEB a motion to review the OEB's January 5, 2012 decision.

On February 6, 2012, LDC filed a notice of appeal with the Ontario Divisional Court regarding the OEB's January 5, 2012 decision.

On May 10, 2012, LDC filed the 2012-2014 IRM/ICM Rate Application. The formulaic adjustment, requested by LDC, follows the guidelines provided by the OEB and seeks to increase the current revenue requirement by 0.68% to $525.5 million for 2012, $529.1 million for 2013 and $532.7 million for 2014. The 2013 and 2014 formulaic adjustment may be subject to change depending on future inflation and market data.

The ICM proposed by LDC establishes rate riders allowing for the recovery of capital spending of $275.7 million in 2012, $361.5 million in 2013 and $266.5 million in 2014 in excess of the OEB's threshold amounts. The calculation of the related requested rate riders was derived using guidelines provided by the OEB. Accordingly, when factoring the amount of capital currently included in LDC's electricity distribution rates, the total amount of capital requested amounts to $448.7 million in 2012, $534.5 million in 2013 and $439.5 million in 2014.

The 2012-2014 IRM/ICM Rate Application is expected to be subject to an in-depth review by the OEB over the next few months. There can be no assurance that the OEB will allow for the total or partial recovery of the capital expenditure balances requested in the 2012-2014 IRM/ICM Rate Application. The outcome of the 2012-2014 IRM/ICM Rate Application could have a material impact on the Corporation's consolidated financial statements in the future.

CDM Activities

On March 31, 2010, the Minister of Energy and Infrastructure of Ontario, under the guidance of sections 27.1 and 27.2 of the *Ontario Energy Board Act, 1998* (Ontario), directed the OEB to establish CDM targets to be met by electricity distributors. Accordingly, on November 12, 2010, the OEB amended LDC's distribution licence to require LDC, as a condition of its licence, to achieve 1,304 GWh of energy savings and 286 Megawatts of summer peak demand savings, over the period beginning January 1, 2011 through December 31, 2014.

Effective January 1, 2011, LDC entered into an agreement with the OPA to deliver CDM programs in the amount of approximately $50.0 million extending from January 1, 2011 to December 31, 2014 (the "Master CDM Program Agreement"). As at March 31, 2012, LDC received approximately $27.6 million from the OPA for the delivery of CDM programs under the Master CDM Program Agreement. All programs to be delivered under the Master CDM Program Agreement are fully funded and paid in advance by the OPA. These programs are expected to support the achievement of the mandatory CDM targets described above.

OEB PILs Proceeding

The OEB conducted a review of the Payments In Lieu of Corporate Taxes ("PILs") variances accumulated in regulatory variance accounts for the period from October 1, 2001 to April 30, 2006 for certain Municipal Electricity Utilities ("MEUs"). On June 24, 2011, the OEB issued its decision for these MEUs and provided guidelines for the calculation and further disposition of the balances accumulated in the PILs regulatory variance accounts. The OEB has issued interrogatories and decisions for other MEUs subsequent to its previous decision.

LDC has reviewed the balances of its PILs regulatory variance accounts and applied the guidelines provided by the OEB. As at March 31, 2012, LDC estimated its liability at approximately $6.6 million. This balance has been recorded in the Corporation's Interim Consolidated Financial Statements. LDC intends to apply for disposition of this balance in 2012 as part of its 2012-2014 IRM/ICM Rate Application. The amount to be approved by the OEB will be based on the OEB's interpretation and application of its guidelines and the final balance which is yet to be approved by the OEB could differ materially from LDC's estimation of its liability.

Payments in Lieu of Additional Municipal and School Taxes

The Ministry of Finance has issued assessments in respect of payments in lieu of additional municipal and school taxes under section 92 of the *Electricity Act, 1998* (Ontario) that are in excess of the amounts LDC believes are payable. The dispute arose as a result of inaccurate information incorporated into Ontario Regulation 224/00. The Corporation has worked with the Ministry of Finance to resolve this issue, and as a result the Ministry of

Finance issued Ontario Regulation 423/11 on August 31, 2011. The new regulation revoked Ontario Regulation 224/00 and corrected inaccurate information retroactively to 1999.

The balance assessed by the Ministry of Finance on its most recent statement of account amounts to approximately $10.0 million above the balance accrued by the Corporation. While the Corporation expects that reassessments will be issued as a consequence of the change in regulation, there can be no assurance that the Corporation will not have to pay the full assessed balance in the future.

Legal Proceedings

In the ordinary course of business, the Corporation is subject to various litigation and claims with customers, suppliers, former employees and other parties. On an ongoing basis, the Corporation assesses the likelihood of any adverse judgments or outcomes as well as potential ranges of probable costs and losses. A determination of the provision required, if any, for these contingencies is made after an analysis of each individual issue. The provision may change in the future due to new developments in each matter or changes in approach, such as a change in settlement strategy.

Christian Helm Class Action

On December 6, 2010, a statement of claim in a proposed class action was issued against LDC. The claim sought general and special damages in the amount of $100.0 million for disgorgement of unjust gains allegedly resulting from the receipt of interest on overdue accounts in contravention of the *Interest Act* (Canada). On April 30, 2012, a settlement reached by the parties was approved by Order of the Ontario Superior Court of Justice. Pursuant to the terms of the Order, LDC will pay the amount of $5.8 million plus costs in settlement of all claims, the action has been dismissed, and the claims by all class members have been released. The Corporation accrued a liability to cover the expected settlement in 2010.

2 Secord Avenue

An action was commenced against LDC in September 2008 in the Ontario Superior Court of Justice under the *Class Proceedings Act, 1992* (Ontario) ("Class Proceedings Act") seeking damages in the amount of $30.0 million as compensation for damages allegedly suffered as a result of a fire and explosion in an underground vault at 2 Secord Avenue on July 20, 2008. This action is at a preliminary stage. The statement of claim has been served on LDC, a statement of defence and third party claim have been served by LDC and a third party defence and counterclaim against LDC seeking damages in the amount of $51.0 million have been filed. A certification order has been issued. Affidavits of documents have been produced by LDC to the other parties and examinations for discovery have commenced and are continuing. Given the preliminary status of this action, it is not possible to reasonably quantify the effect, if any, of this action on the financial performance of the Corporation. If damages were awarded, LDC would make a claim under its liability insurance which the Corporation believes would cover any damages which may become payable by LDC in connection with the action.

On December 20, 2010, LDC was served with a statement of claim by the City seeking damages in the amount of $2.0 million as a result of the fire at 2 Secord Avenue. A statement of defence and a third party claim have been served. Given the preliminary status of this action, it is not possible to reasonably quantify the effect, if any, of this action on the financial performance of the Corporation. If damages were awarded, LDC would make a claim under its liability insurance which the Corporation believes would cover any damages which may become payable by LDC in connection with the action.

By order of the court, the above actions and a smaller non-class action commenced in April 2009 involving the same incident will be tried at the same time or consecutively.

2369 Lakeshore Boulevard West

A third party action was commenced against LDC in October 2009 in the Ontario Superior Court of Justice under the Class Proceedings Act seeking damages in the amount of $30.0 million as compensation for damages allegedly suffered as a result of a fire in the electrical room at 2369 Lakeshore Boulevard West on March 19, 2009. Subsequently, in March 2010, the plaintiff in the main action amended its statement of claim to add LDC as a defendant. The plaintiff in the main action seeks damages in the amount of $10.0 million from LDC. Both actions

are at a preliminary stage and the certification hearing is scheduled for September 2012. Statements of defence to the main action and to the third party claim have not been filed. Accordingly, given the preliminary status of these actions, it is not possible at this time to reasonably quantify the effect, if any, of these actions on the financial performance of the Corporation. If damages were awarded, LDC would make a claim under its liability insurance which the Corporation believes would cover any damages which may become payable by LDC in connection with these actions.

Another third party action was commenced against LDC in October 2009 in the Ontario Superior Court of Justice seeking damages in the amount of $30.0 million as compensation for damages allegedly suffered as a result of the fire at 2369 Lakeshore Boulevard West. Subsequently, in March 2010, the plaintiff in the main action amended its statement of claim to add LDC as a defendant. The plaintiff in the main action seeks damages in the amount of $0.4 million from LDC. LDC has filed a statement of defence, crossclaim and counterclaim. Examinations for discovery have not taken place, notwithstanding a court ordered timetable to have them completed by February 29, 2012. Accordingly, given the preliminary status of these actions, it is not possible at this time to reasonably quantify the effect, if any, of these actions on the financial performance of the Corporation. If damages were awarded, LDC would make a claim under its liability insurance which the Corporation believes would cover any damages which may become payable by LDC in connection with these actions.

On August 29, 2011, LDC was served with a statement of claim by the owner of the building and the property management company for the building seeking damages in the amount of $2.0 million as a result of the fire at 2369 Lakeshore Boulevard West. LDC has filed a statement of defence and counterclaim. Given the preliminary status of this action, it is not possible to reasonably quantify the effect, if any, of this action on the financial performance of the Corporation. If damages were awarded, LDC would make a claim under its liability insurance which the Corporation believes would cover any damages which may become payable by LDC in connection with the action.

Share Capital

The authorized share capital of the Corporation consists of an unlimited number of common shares of which 1,000 common shares are issued and outstanding as at the date hereof.

Transactions with Related Parties

The City is the sole shareholder of the Corporation. Subsidiaries of the Corporation provide certain services to the City at commercial and regulated rates, including electricity, street lighting and energy management services. All transactions with the City are conducted at prevailing market prices and normal trade terms. Additional information with respect to related party transactions between the Corporation and its subsidiaries, as applicable, and the City is set out below.

Transactions with Related Parties Summary
Three months ended March 31
(in thousands of Canadian dollars)

	2012 $	2011 $
Revenues	40,415	42,016
Operating expenses and capital expenditures	5,049	4,949
Dividends	28,966	14,063

Transactions with Related Parties Summary (in thousands of Canadian dollars)		
	As at March 31 2012 $	As at December 31 2011 $
Accounts receivable, net of allowance for doubtful accounts	6,829	8,412
Unbilled revenue	10,628	9,363
Other assets	7,257	7,279
Accounts payable and accrued liabilities	27,036	25,085
Customers' advance deposits	8,734	8,714

Revenues represent amounts charged to the City primarily for electricity and street lighting services. Operating expenses and capital expenditures represent amounts charged by the City for purchased road cut repairs, property taxes and other services. Dividends represent dividends paid to the City.

Accounts receivable, net of allowance for doubtful accounts, represent receivables from the City primarily for street lighting, electricity and other services. Unbilled revenue represents receivables from the City related to the provision of electricity and street lighting services provided but not yet billed. Other assets represent amounts for prepaid land leases from the City. Accounts payable and accrued liabilities represent amounts payable to the City relating to road cut repairs, property taxes and other services, as well as funds received from the City for the construction of electricity distribution assets. Customers' advance deposits represent funds received from the City for future expansion projects.

See note 20 to the Interim Consolidated Financial Statements.

Non-GAAP Financial Measures

The Corporation's MD&A includes "net revenue" which is a non-GAAP financial measure. The definition of net revenues is revenue minus the cost of purchased power. This measure does not have any standard meaning prescribed by US GAAP and is not necessarily comparable to similarly titled measures of other companies. The Corporation uses this measure to assess its performance and to further make operating decisions.

Significant Accounting Policies

The Interim Consolidated Financial Statements of the Corporation have been prepared in accordance with US GAAP, including accounting principles prescribed by the OEB in the AP Handbook, and are presented in Canadian dollars. In preparing the Interim Consolidated Financial Statements, management makes estimates and assumptions which affect the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities at the date of the Interim Consolidated Financial Statements and the reported amounts of revenues and expenses for the period. Actual results could differ from those estimates, including changes as a result of future decisions made by the OEB, the Ministry of Energy, or the Ministry of Finance. The significant accounting policies of the Corporation are summarized in note 4 to the Interim Consolidated Financial Statements.

Future Accounting Pronouncements

A number of new standards and interpretations are not yet effective for the period ended March 31, 2012. The Corporation continues to analyze these standards but has initially determined that the following could have a significant effect on the consolidated financial statements.

In September 2011, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") No. 2011-09, "Compensation – Retirement Benefits – Multiemployer Plans (Subtopic 715-80): *Disclosures about an Employer's Participation in a Multiemployer Plan*" ("ASU 2011-09"). The amendments require additional disclosures about employers' participation in these types of plans including information about the plan's funded status if it is readily available. ASU 2011-09 is effective for fiscal years ending after December 15, 2011 and will be applied retrospectively. Early adoption is permitted. The Corporation has elected to include the additional disclosures related to the multi-employer pension plans in the Interim Consolidated Financial Statements.

In December 2011, the FASB issued ASU No. 2011-11, "Balance Sheet (Topic 210): *Disclosures about Offsetting Assets and Liabilities*" ("ASU 2011-11"). The amendments require an entity to disclose both gross and net information about financial instruments and transactions eligible for offset in the consolidated balance sheet. ASU 2011-11 is effective for fiscal years, and interim periods within those years, beginning on or after January 1, 2013. Retrospective application is required. The adoption of this amendment is expected to increase disclosures related to offsetting assets and liabilities and is not expected to have an impact to the Corporation's consolidated balance sheets.

US GAAP Transition

Publicly accountable enterprises in Canada were required to adopt International Financial Reporting Standards ("IFRS") in place of Canadian GAAP for interim and annual reporting purposes for fiscal years beginning on or after January 1, 2011. In the absence of a definitive plan to consider the issuance of a rate-regulated accounting standard by the International Accounting Standards Board, the Corporation decided to evaluate the option of adopting US GAAP effective January 1, 2012 as an alternative to IFRS. On August 26, 2011, the Board of Directors of the Corporation approved the adoption of US GAAP for financial reporting purposes for the year beginning on January 1, 2012.

The accompanying Interim Consolidated Financial Statements are the Corporation's first interim consolidated financial statements prepared in accordance with US GAAP. The accounting policies set out in note 4 to the Interim Consolidated Financial Statements have been applied consistently in preparing the Interim Consolidated Financial Statements and the comparative periods. The Corporation's first US GAAP annual consolidated financial statements will be dated December 31, 2012.

The quantification and reconciliation of the Corporation's consolidated balance sheet as at December 31, 2011, prepared in accordance with US GAAP as compared to Canadian GAAP is an increase to both total assets and total liabilities of approximately $71.7 million. The increase is primarily due to the recognition of unamortized actuarial losses and prior service costs and the reclassification of debt issuance costs in accordance with US GAAP. With respect to the consolidated statement of income and comprehensive income for the period ended December 31, 2011, net income was not impacted due to the Corporation's continued ability to apply rate-regulated accounting policies.

Based on the detailed assessment of the key accounting areas for which significant Canadian GAAP and US GAAP differences were identified, there is no impact to equity and net earnings from that previously reported in the Interim and Annual Consolidated Financial Statements. The Corporation has adjusted amounts reported previously in its Interim and Annual Consolidated Financial Statements prepared in accordance with Canadian GAAP. For reporting purposes, the transition date to US GAAP is January 1, 2011, which is the commencement of the 2011 interim comparative period to the Corporation's 2012 Interim Consolidated Financial Statements. A reconciliation of the transition from Canadian GAAP to US GAAP from January 1, 2011 and December 31, 2011 is provided in note 24 to the Interim Consolidated Financial Statements.

During the transition to US GAAP, there was no significant impact on the Corporation's internal controls, information technology systems and financial reporting expertise requirements. The Corporation has completed topic-specific and relevant training to affected finance and operational teams on all key differences between Canadian GAAP and US GAAP, including management, the Board of Directors, and relevant committees thereof, including the audit committee. During the remainder of 2012, the Corporation will continue to focus on training for any key developments in US GAAP and the potential impacts to the Corporation's consolidated financial statements. Due to the limited differences between Canadian GAAP and US GAAP, the Corporation's debt covenants were not impacted by the conversion to US GAAP.

On February 28, 2012, LDC submitted a letter to the OEB requesting an accounting order establishing a deferral account to record the accounting differences between Canadian GAAP and US GAAP. The OEB's approval to establish this deferral account would allow the Corporation to record the financial impacts associated with the accounting framework transition for regulatory reporting purposes. The OEB's decision on this accounting order application will not constitute a decision with respect to the Corporation's use of US GAAP for regulatory reporting purposes. LDC will seek the OEB's approval to use US GAAP for regulatory reporting purposes in its next COS application. On May 1, 2012, the OEB Board Staff submitted its recommendation to the OEB in support of approving the deferral account. A final decision is still pending.

Selected Financial Highlights

The following table sets forth selected financial information of the Corporation for the three months ended March 31, 2012 and for the comparable period in 2011. This information has been derived from the Interim Consolidated Financial Statements.

Selected Financial Highlights
Three months ended March 31
(in thousands of Canadian dollars, unaudited)

	2012 $	2011 $
Net revenues [1]	137,230	143,369
Operating expenses [1]	68,182	66,175
Net income (loss) [1]	(12,826)	25,452
Capital expenditures [2]	65,378	100,348

Notes:

[1] See "Results of Operations" for further details on net revenues, operating expenses and net income (loss).
[2] See "Liquidity and Capital Resources" for further details on capital expenditures.

Additional Information

Additional information with respect to the Corporation (including its annual information form) is available at www.sedar.com.

Toronto, Canada

May 17, 2012

CONSOLIDATED FINANCIAL STATEMENTS
JUNE 30, 2012

INTERIM CONSOLIDATED BALANCE SHEETS

[in thousands of Canadian dollars, unaudited]

	As at June 30, 2012 $	As at December 31, 2011 $
		[note 24]
ASSETS		
Current		
Cash and cash equivalents	**120,831**	154,256
Investments	**-**	34,002
Accounts receivable, net of allowance for doubtful accounts *[note 16[b]]*	**192,383**	183,272
Unbilled revenue *[note 16[b]]*	**272,849**	262,058
Income tax receivable	**19,053**	11,312
Inventories *[note 5]*	**6,372**	6,891
Regulatory assets *[note 9]*	**3,833**	-
Other assets *[note 6]*	**6,989**	5,409
Total current assets	**622,310**	657,200
Property, plant and equipment, net *[note 7]*	**2,428,383**	2,399,497
Intangible assets, net *[note 8]*	**128,404**	112,982
Regulatory assets *[note 9]*	**135,846**	143,038
Other assets *[note 10]*	**11,822**	12,423
Deferred income tax assets *[note 9]*	**198,951**	202,367
Total assets	**3,525,716**	3,527,507
LIABILITIES AND SHAREHOLDER'S EQUITY		
Current		
Accounts payable and accrued liabilities *[note 16[b]]*	**396,890**	412,412
Restructuring accrual *[note 12]*	**14,850**	-
Customers' advance deposits	**44,245**	40,238
Deferred revenue	**19,259**	13,359
Debentures *[note 13]*	**470,041**	-
Post-retirement benefits *[note 14]*	**8,537**	7,915
Other liabilities *[note 21]*	**1,862**	2,182
Regulatory liabilities *[note 9]*	**-**	7,293
Total current liabilities	**955,684**	483,399
Restructuring accrual *[note 12]*	**4,414**	-
Customers' advance deposits	**13,396**	15,800
Debentures *[note 13]*	**999,516**	1,469,527
Post-retirement benefits *[note 14]*	**240,143**	236,411
Other liabilities *[note 21]*	**10,576**	11,301
Regulatory liabilities *[note 9]*	**201,073**	203,919
Asset retirement obligations *[note 15]*	**4,920**	4,902
Total liabilities	**2,429,722**	2,425,259
Commitments, contingencies and subsequent events *[notes 21, 22 and 26]*		
Shareholder's equity		
Share capital *[note 19]*	**567,817**	567,817
Retained earnings	**528,177**	534,431
Total shareholder's equity	**1,095,994**	1,102,248
Total liabilities and shareholder's equity	**3,525,716**	3,527,507

The accompanying notes are an integral part of the interim consolidated financial statements.

INTERIM CONSOLIDATED STATEMENTS OF NET INCOME AND COMPREHENSIVE INCOME

[in thousands of Canadian dollars, except for per share amounts, unaudited]

	Three months ended June 30, 2012 $	Three months ended June 30, 2011 $	Six months ended June 30, 2012 $	Six months ended June 30, 2011 $
		[note 24]		*[note 24]*
Revenues	**709,700**	686,646	**1,409,360**	1,390,834
Costs				
Purchased power	**565,053**	547,660	**1,127,483**	1,108,479
Operating expenses	**49,646**	65,611	**117,828**	131,786
Depreciation and amortization	**35,132**	35,414	**70,560**	68,886
	649,831	648,685	**1,315,871**	1,309,151
Income before the following:	**59,869**	37,961	**93,489**	81,683
Net financing charges	**(18,170)**	(18,066)	**(36,820)**	(36,962)
Gain on disposals of property, plant and equipment	**-**	1,753	**-**	4,717
Restructuring costs *[note 12]*	**-**	-	**(27,796)**	-
Income before income taxes	**41,699**	21,648	**28,873**	49,438
Income tax expense (recovery) *[note 18]*	**161**	(2,622)	**161**	(284)
Net income and comprehensive income for the period	**41,538**	24,270	**28,712**	49,722
Basic and fully diluted net income per share *[note 23]*	**41,538**	24,270	**28,712**	49,722

INTERIM CONSOLIDATED STATEMENTS OF SHAREHOLDER'S EQUITY

[in thousands of Canadian dollars, unaudited]

	Three months ended June 30, 2012 $	Three months ended June 30, 2011 $	Six months ended June 30, 2012 $	Six months ended June 30, 2011 $
Share capital *[note 19]*	**567,817**	567,817	**567,817**	567,817
Retained earnings, beginning of period	**492,639**	482,951	**534,431**	471,562
Net income for the period	**41,538**	24,270	**28,712**	49,722
Dividends *[notes 19 and 20]*	**(6,000)**	(6,000)	**(34,966)**	(20,063)
Retained earnings, end of period	**528,177**	501,221	**528,177**	501,221
Total shareholder's equity	**1,095,994**	1,069,038	**1,095,994**	1,069,038

The accompanying notes are an integral part of the interim consolidated financial statements.

INTERIM CONSOLIDATED STATEMENTS OF CASH FLOWS

[in thousands of Canadian dollars, unaudited]

	Three months ended June 30,		Six months ended June 30,	
	2012 **$**	2011 $	**2012** **$**	2011 $
OPERATING ACTIVITIES				
Net income for the period	**41,538**	24,270	**28,712**	49,722
Adjustments for non-cash items				
Depreciation and amortization	**35,132**	35,414	**70,560**	68,886
Change in other non-current assets	**51**	117	**330**	440
Change in other non-current liabilities	**927**	(177)	**(735)**	(557)
Restructuring accrual	**(3,608)**	-	**4,414**	-
Post-retirement benefits	**2,177**	11,042	**4,354**	22,085
Deferred income taxes	**534**	(113)	**546**	(404)
Gain on disposals of property, plant and equipment	**-**	(1,753)	**-**	(4,717)
Changes in non-cash working capital balances				
Decrease (increase) in accounts receivable	**17,986**	19,511	**(9,111)**	(36,799)
Increase in unbilled revenue	**(28,959)**	(15,087)	**(10,791)**	(11,492)
Increase in income tax receivable	**(4,475)**	(7,668)	**(7,741)**	(10,563)
Decrease (increase) in inventories	**245**	(4)	**519**	62
Decrease (increase) in other current assets	**(112)**	1,396	**(1,580)**	(1,578)
Decrease in accounts payable and accrued liabilities	**(28,548)**	(35,145)	**(15,522)**	(8)
Increase (decrease) in restructuring accrual	**(1,790)**	-	**14,850**	-
Increase (decrease) in deferred revenue	**(2,572)**	6,394	**5,900**	8,606
Decrease in other current liabilities	**(75)**	(107)	**(320)**	(264)
Net cash provided by operating activities	**28,451**	38,090	**84,385**	83,419
INVESTING ACTIVITIES				
Purchase of property, plant and equipment *[note 7]*	**(45,760)**	(93,013)	**(89,061)**	(175,969)
Purchase of intangible assets *[note 8]*	**(4,132)**	(11,834)	**(26,209)**	(29,226)
Purchase of investments	**-**	(9,014)	**-**	(59,041)
Proceeds from investments	**-**	25,000	**34,000**	25,000
Net change in regulatory assets and liabilities	**13,951**	(16,750)	**(3,910)**	(27,045)
Proceeds on disposals of property, plant and equipment	**232**	2,057	**733**	4,211
Net cash used in investing activities	**(35,709)**	(103,554)	**(84,447)**	(262,070)
FINANCING ACTIVITIES				
Dividends paid *[notes 19 and 20]*	**(6,000)**	(6,000)	**(34,966)**	(20,063)
Increase (decrease) in customers' advance deposits	**957**	(4,893)	**1,603**	(11,699)
Net cash used in financing activities	**(5,043)**	(10,893)	**(33,363)**	(31,762)
Net decrease in cash and cash equivalents during the period	**(12,301)**	(76,357)	**(33,425)**	(210,413)
Cash and cash equivalents, beginning of period	**133,132**	196,095	**154,256**	330,151
Cash and cash equivalents, end of period	**120,831**	119,738	**120,831**	119,738
Supplementary cash flow information				
Total interest paid	**37,561**	39,502	**37,824**	39,534
Total income taxes paid	**2,736**	3,729	**6,066**	9,253

The accompanying notes are an integral part of the interim consolidated financial statements.

1. INCORPORATION

On June 23, 1999, Toronto Hydro Corporation [the "Corporation"] was incorporated under the *Business Corporations Act* (Ontario) [the "OBCA"], and is wholly-owned by the City of Toronto [the "City"]. The incorporation was required in accordance with the provincial government's *Electricity Act, 1998* (Ontario) ["Electricity Act"].

The Corporation supervises the operations of, and provides corporate, management services and strategic direction to two subsidiaries incorporated under the OBCA and wholly-owned by the Corporation:

[i] Toronto Hydro-Electric System Limited ["LDC"] (incorporated June 23, 1999) – distributes electricity to customers located in the City and is subject to rate regulation. LDC is also engaged in the delivery of Conservation and Demand Management ["CDM"] activities; and

[ii] Toronto Hydro Energy Services Inc. (incorporated June 23, 1999) – provides street lighting services.

The principal business of the Corporation and its subsidiaries is the distribution of electricity by LDC.

2. BASIS OF PRESENTATION

These unaudited interim consolidated financial statements of the Corporation have been prepared in accordance with United States ["US"] Generally Accepted Accounting Principles ["GAAP"] with respect to the preparation of interim financial information, and are presented in Canadian dollars. The disclosures in these statements do not conform in all respects to the requirements of US GAAP for annual consolidated financial statements. The Corporation's annual and interim consolidated financial statements were prepared in accordance with Canadian GAAP until December 31, 2011. The comparative consolidated financial statements have been adjusted retroactively from the consolidated financial statements previously presented to conform to the presentation of the Corporation's 2012 interim consolidated financial statements prepared in accordance with US GAAP. The Corporation's first US GAAP annual consolidated financial statements will be dated December 31, 2012.

A reconciliation of the consolidated balance sheets between Canadian GAAP and US GAAP as at January 1, 2011 and December 31, 2011 and a reconciliation of net income for the three months and six months ended June 30, 2011 accompany the interim consolidated financial statements *[note 24]*.

3. REGULATION

In April 1999, the Government of Ontario began restructuring the Province of Ontario ["Ontario"]'s electricity industry. Under regulations passed pursuant to the restructuring, LDC and other electricity distributors have been purchasing their electricity from the wholesale market administered by the Independent Electricity System Operator ["IESO"] and recovering the costs of electricity and certain other costs at a later date in accordance with procedures mandated by the Ontario Energy Board [the "OEB"].

The OEB has regulatory oversight of electricity matters in Ontario. The *Ontario Energy Board Act, 1998* (Ontario) [the "OEB Act"] sets out the OEB's authority to issue a distribution licence that must be obtained by owners or operators of an electricity distribution system in Ontario. The OEB prescribes licence requirements and conditions including, among other things, specified accounting records, regulatory accounting principles, separation of accounts for separate businesses, and filing process requirements for rate-setting purposes.

The OEB's authority and responsibilities include the power to approve and fix rates for the transmission and distribution of electricity, the power to provide continued rate protection for rural and remote electricity customers, and the responsibility for ensuring that electricity distribution companies fulfill their obligations to connect and service customers.

LDC is required to charge its customers for the following amounts (all of which, other than distribution charges, represent a pass through of amounts payable to third parties):

[i] *Distribution Charges*. Distribution charges are designed to recover the costs incurred by LDC in delivering electricity to customers and the OEB-allowed rate of return. Distribution charges are regulated by the OEB and are comprised of a fixed charge and a usage-based (consumption) charge. The volume of electricity consumed by LDC's customers during any period is governed by events largely outside LDC's control (principally, sustained periods of hot or cold weather which increase the consumption of electricity, and sustained periods of moderate weather which decrease the consumption of electricity).

[ii] *Electricity Price and Regulated Adjustments*. The electricity price and regulated adjustments represent the pass through of the commodity and other costs of electricity.

[iii] *Retail Transmission Rate*. The retail transmission rate represents a pass through of wholesale costs incurred by distributors in respect of the transmission of electricity from generating stations to local areas. Retail transmission rates are regulated by the OEB.

[iv] *Wholesale Market Service Charge*. The wholesale market service charge represents a pass through of various wholesale market support costs. Retail rates for the recovery of wholesale market service charges are regulated by the OEB.

LDC is required to satisfy and maintain prudential requirements with the IESO, which include credit support with respect to outstanding market obligations in the form of letters of credit, cash deposits or guarantees from third parties with prescribed credit ratings.

a) Electricity Distribution Rates

Regulatory developments in Ontario's electricity industry, including current and possible future consultations between the OEB and interested stakeholders, may affect LDC's electricity distribution rates and other permitted recoveries in the future.

LDC's electricity distribution rates for 2011 were determined through an application under the Cost of Service ["COS"] framework. The COS framework sets electricity distribution rates using a detailed examination of evidence and an assessment of the costs incurred by an electricity distributor to provide services to its customers.

On July 7, 2011, the OEB issued its decision regarding LDC's electricity distribution rates for 2011. The decision provided for a distribution revenue requirement and rate base of $522,044,000 and $2,298,227,000, respectively. In addition, the decision provided for capital program spending levels and operating, maintenance and administration spending levels of $378,800,000 and $238,000,000, respectively.

On August 26, 2011, LDC filed a rate application, following the COS framework, with the OEB seeking approval of separate and successive revenue requirements and corresponding electricity distribution rates for 2012, 2013 and 2014. The requested distribution revenue requirements for these years were $571,369,000, $639,492,000, and $712,777,000, respectively, and the expected rate bases for these years were $2,636,291,000, $3,053,499,000, and $3,503,165,000, respectively.

Pursuant to the Incentive Regulation Mechanism ["IRM"] framework, the OEB established, as a preliminary issue in the above application, that it would consider the question of whether the application filed by LDC under the COS framework was acceptable or whether it should be dismissed. The IRM framework provides for an adjustment to an electricity distributor's rates based on a formulaic calculation with the possibility to request an Incremental Capital Module ["ICM"] to address specific capital expenditure needs not covered by the formulaic calculation. The review of an ICM application is done by the OEB following defined criteria, such as materiality, causation and prudence.

LDC filed evidence supporting its position for electricity distribution rates to be set under the COS framework for 2012, 2013 and 2014. The OEB established a process by which a portion of LDC's evidence was tested during an oral hearing held in November 2011.

On January 5, 2012, the OEB rendered its decision on the preliminary issue and dismissed LDC's COS framework application for 2012, 2013 and 2014. In its decision, the OEB found that LDC was not permitted to deviate from the standard IRM framework cycle. Accordingly, LDC was required to file its request for electricity distribution rates for 2012, 2013, and 2014 pursuant to the IRM framework and to use the ICM to request the capital needed for infrastructure renewal.

On January 25, 2012, LDC filed a motion with the OEB to review the OEB's January 5, 2012 decision.

On February 6, 2012, LDC filed a notice of appeal with the Ontario Divisional Court regarding the OEB's January 5, 2012 decision.

On May 10, 2012, LDC filed an application for electricity distribution rates for 2012, 2013, and 2014 using the IRM framework, including the filing of an ICM application. The formulaic adjustment, requested by LDC, follows the guidelines provided by the OEB and seeks to increase the current revenue requirement by 0.68% to $525,500,000 for 2012, $529,100,000 for 2013 and $532,700,000 for 2014. The 2013 and 2014 formulaic adjustment may be subject to change depending on future inflation and market data.

The ICM proposed by LDC establishes rate riders allowing for the recovery of capital spending of $275,700,000 for 2012, $361,500,000 for 2013 and $266,500,000 for 2014 in excess of the OEB's threshold amounts. The calculation of the related requested rate riders was derived using guidelines provided by the OEB. Accordingly, when factoring in the amount of capital currently included in LDC's electricity distribution rates, the total amount of capital requested amounts to $448,700,000 for 2012, $534,500,000 for 2013 and $439,500,000 for 2014.

The current application is expected to be subject to an in-depth review by the OEB over the next few months. There can be no assurance that the OEB will allow for the total or partial recovery of the capital expenditure balances requested in the current application. The outcome of the current application could have a material impact on the Corporation's consolidated financial statements in the future.

b) CDM Activities

On March 31, 2010, the Minister of Energy and Infrastructure of Ontario, under the guidance of sections 27.1 and 27.2 of the OEB Act, directed the OEB to establish CDM targets to be met by electricity distributors. Accordingly, on November 12, 2010, the OEB amended LDC's distribution licence to require LDC, as a condition of its licence, to achieve 1,304 Gigawatt-Hours of energy savings and 286 Megawatts of summer peak demand savings, over the period beginning January 1, 2011 through December 31, 2014.

Effective January 1, 2011, LDC entered into an agreement with the Ontario Power Authority ["OPA"] to deliver CDM programs in the amount of approximately $50,000,000 extending from January 1, 2011 to December 31, 2014. As at June 30, 2012, LDC received approximately $27,620,000 [December 31, 2011 - $19,875,000] from the OPA for the delivery of CDM programs. All programs to be delivered are fully funded and paid in advance by the OPA. Upon expiration of the agreement, LDC is required to repay to the OPA any excess funding received for program administration less any cost efficiency incentives. These programs are expected to support the achievement of the mandatory CDM targets described above.

4. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

The interim consolidated financial statements of the Corporation have been prepared in accordance with US GAAP, including accounting principles prescribed by the OEB in the "Accounting Procedures Handbook for Electricity Distributors" [the "AP Handbook"], and reflect the significant accounting policies summarized below:

a) Basis of consolidation

The interim consolidated financial statements include the accounts of the Corporation and its wholly-owned subsidiaries. All intercompany balances and transactions have been eliminated.

b) Regulation

The following regulatory treatments have resulted in accounting treatments which differ from US GAAP for enterprises operating in an unregulated environment:

Regulatory Assets and Liabilities

The Corporation has determined that its assets and liabilities arising from rate-regulated activities qualify for the application of regulatory accounting treatment in accordance with Financial Accounting Standards Board ["FASB"] Accounting Standards Codification 980 – "Regulated Operations" ["ASC 980"]. Under rate-regulated accounting ["RRA"], the timing and recognition of certain expenses and revenues may differ from those otherwise expected under US GAAP in order to appropriately reflect the economic impact of regulatory decisions regarding the Corporation's regulated revenues and expenditures. These timing differences are recorded as regulatory assets and regulatory liabilities on the Corporation's consolidated balance sheets and represent existing rights and obligations regarding cash flows expected to be recovered from or refunded to customers, based on decisions and approvals by the OEB. Regulatory assets and liabilities can be recognized for rate-setting and financial reporting purposes only if the OEB directs the relevant regulatory treatment or if future OEB direction is judged to be probable. In the event that the disposition of these balances was assessed to no longer be probable, the balances would be recorded in the Corporation's consolidated statements of net income and comprehensive income in the period that the assessment is made. The measurement of regulatory assets and liabilities is subject to certain estimates and assumptions, including assumptions made in the interpretation of the regulation and the OEB's decisions.

Regulatory assets and liabilities are classified as current if they are expected to be recovered from, or refunded to, customers within 12 months after each reporting period. All other regulatory asset and liability balances are classified as long-term on the consolidated balance sheets.

Contributions in aid of construction

Capital contributions received are used to finance additions to property, plant and equipment of LDC. According to the accounting principles prescribed by the OEB in the AP Handbook, capital contributions received are treated as a credit to property, plant and equipment. The amount is subsequently depreciated by a charge to accumulated depreciation and a credit to depreciation expense at an equivalent rate to that used for the depreciation of the related property, plant and equipment.

Allowance for funds used during construction

The AP Handbook provides for the inclusion of an Allowance for Funds Used During Construction ["AFUDC"] when capitalizing construction-in-progress assets, until such time as the asset is substantially complete. A concurrent credit of the same amount is made to net financing charges when the allowance is capitalized. The interest rate for capitalization is prescribed by the OEB and modified on a periodic basis, and is applied to the balance of the construction-in-progress assets on a simple interest basis. The interest rate for capitalization for the period from January 1, 2012 to March 31, 2012 was 3.92%, and from April 1, 2012 to June 30, 2012 was 3.51% [January 1, 2011 to June 30, 2011 - 4.29%]. AFUDC is included in property, plant and equipment and intangible assets for financial reporting purposes, charged to operations through depreciation and amortization expense over the service life of the related assets and recovered through future revenue.

c) Cash and cash equivalents

Cash and cash equivalents include cash in bank accounts and short-term investments with terms to maturity of 90 days or less from their date of acquisition.

d) Accounts receivable

Accounts receivable are recorded at the invoiced amount and do not bear interest. The carrying amount of accounts receivable is reduced through an allowance for doubtful accounts and the amount of the related impairment loss is recognized in the consolidated statements of net income and comprehensive income. Subsequent recoveries of receivables previously provisioned and written off are credited to the consolidated statements of net income and comprehensive income. Management estimates uncollectible accounts receivable after considering historical loss experience and the characteristics of existing accounts.

e) Investments

Investments with terms to maturity of greater than 90 days from their date of acquisition are classified as held to maturity and included in current assets.

f) Inventories

Inventories consist primarily of small consumable materials mainly related to the maintenance of the electricity distribution infrastructure. The Corporation classifies all major construction related components of its electricity distribution system infrastructure to property, plant and equipment. Once capitalized, these items are not depreciated until they are put into service. Inventories are carried at the lower of cost and market, with cost determined on an average cost basis net of a provision for obsolescence.

g) Property, plant and equipment

Property, plant and equipment are stated at cost and are removed from the accounts at the end of their estimated average service lives, except in those instances where specific identification allows their removal at retirement or disposition.

In the event that facts and circumstances indicate that property, plant and equipment may be impaired, an evaluation of recoverability is performed. For purposes of such an evaluation, the estimated future undiscounted cash flows associated with the asset are compared to the carrying amount of the asset to determine if a write-down is required. The impairment loss is measured as the amount by which the carrying amount of the asset exceeds its fair value, which is determined by the estimated future discounted cash flows.

[all tabular amounts in thousands of Canadian dollars, unaudited]

Depreciation is provided on a straight-line basis over the estimated service lives at the following annual rates:

Distribution lines	1.7% to 5.0%
Transformers	3.3% to 5.0%
Stations	2.5% to 10.0%
Meters	2.5% to 6.7%
Buildings	1.3% to 5.0%
Rolling stock	12.5% to 25.0%
Other capital assets	4.0% to 20.0%
Equipment and tools	10.0% to 16.7%
Assets under capital lease	14.3% to 25.0%
Computer hardware	16.7% to 25.0%
Communications	10.0% to 20.0%

Construction in progress relates to assets not currently in use and therefore not depreciated.

h) Intangible assets

Effective January 1, 2012, the Corporation revised its estimate of useful life of its Customer Care and Billing Customer Information System from five years to ten years due to analysis completed related to the useful life assessment. This change has been accounted for on a prospective basis in the interim consolidated financial statements effective January 1, 2012. The change in estimate reduced amortization expense by approximately $2,000,000 for the first six months of 2012 with an offsetting increase in the carrying value of intangible assets, and is expected to impact amortization expense by $4,000,000 per year for all years, with the exception of the last year of the original useful life.

Intangible assets are stated at cost. Amortization is provided on a straight-line basis over the estimated service lives at the following annual rates:

Computer software	10.0% to 25.0%
Contributions	4.0%

Software in development and contributions for work in progress relate to assets not currently in use and therefore are not amortized. Contributions represent payments made to Hydro One Networks Inc. for dedicated infrastructure pursuant to an agreement in order to receive connections to transmission facilities.

i) Deferred debt issuance costs

Debt issuance costs arising from the Corporation's debenture offerings are capitalized within Other assets on the consolidated balance sheets. The deferred charge is amortized over the life of the debenture, using the effective interest method of amortization, and is included in net financing charges.

j) Restructuring

Restructuring charges are recorded based upon planned employee termination dates, site closure and consolidation plans, and contract terminations. Restructuring charges can include severance costs to eliminate a specified number of employee positions, infrastructure charges to vacate facilities and consolidate operations, and contract cancellation costs. The timing of associated cash payments is dependent upon the type of restructuring charge and can extend over a multi-year period.

k) Workplace Safety and Insurance Act

The Corporation is a Schedule 1 employer for workers' compensation under the *Workplace Safety and Insurance Act, 1997* (Ontario) [the "WSIA"]. As a Schedule 1 employer under the WSIA, the Corporation is required to pay annual premiums into an insurance fund established under the WSIA and recognizes expenses based on funding requirements.

l) Revenue recognition

Revenues from the sale of electricity are recorded on a basis of cyclical billings and also include unbilled revenues accrued in respect of electricity delivered and not yet billed.

Other revenues, which include revenues from electricity distribution related services, revenues from the delivery of street lighting services and revenues from demand billable activities, are recognized as the services are rendered.

m) Financial instruments

At inception, all financial instruments which meet the definition of a financial asset or financial liability are recorded at fair value, unless fair value cannot be reliably determined. Gains and losses related to the measurement of financial instruments are reported in the consolidated statements of net income and comprehensive income. Subsequent measurement of each financial instrument will depend on the consolidated balance sheet classification elected by the Corporation. The fair value of a financial instrument is the amount of consideration that would be agreed upon in an arm's length transaction between willing parties.

The following summarizes the accounting classification the Corporation has elected to apply to each of its significant categories of financial instruments:

Cash equivalents and short-term investments	Held for Trading
Investments	Held to Maturity
Accounts receivable and unbilled revenue	Loans and Receivables
Accounts payable and accrued liabilities	Other Financial Liabilities
Obligations under capital lease	Other Financial Liabilities
Customers' advance deposits	Other Financial Liabilities
Debentures	Other Financial Liabilities

The Corporation uses the following methods and assumptions to estimate the fair value of each class of financial instruments for which carrying amounts are included in the consolidated balance sheets:

- Cash equivalents, comprising short-term investments, are classified as "Held for Trading" and are measured at fair value. The carrying amounts approximate fair value because of the short maturity of these instruments.

- Investments are classified as "Held to Maturity" and are measured at amortized cost, which, upon initial recognition, is considered equivalent to fair value. The carrying amounts approximate fair value because of the short maturity of these instruments.

- Accounts receivable and unbilled revenue are classified as "Loans and Receivables" and are measured at amortized cost, which, upon initial recognition, are considered equivalent to fair value. Subsequent measurements are recorded at amortized cost using the effective interest rate method. The carrying amounts approximate fair value because of the short maturity of these instruments.

- Accounts payable and accrued liabilities are classified as "Other Financial Liabilities" and are initially measured at fair value. Subsequent measurements are recorded at amortized cost using the effective interest rate method. The carrying amounts approximate fair value because of the short maturity of these instruments.

- Obligations under capital lease are classified as "Other Financial Liabilities" and are initially measured at fair value. Subsequent measurements are based on a discounted cash flow analysis and approximate the carrying value as management believes that the fixed interest rates are representative of current market rates.

- Customers' advance deposits are classified as "Other Financial Liabilities" and are initially measured at fair value. Subsequent measurements are recorded at amortized cost using the effective interest rate method. The carrying amounts approximate fair value because of the short maturity of the current portion, and the discounted long-term portion approximates the carrying value, taking into account interest accrued on the outstanding balance.

- Debentures are classified as "Other Financial Liabilities" and are initially measured at fair value. The carrying amounts of the debentures are carried at amortized cost, based on an initial fair value as determined at the time using a quoted market price for similar debt instruments. The fair value of the debentures is calculated by discounting the related cash flows at the estimated yield to maturity of similar debt instruments *[note 16[a]]*. While the Corporation has the option to redeem some or all of the debentures at its discretion, this option has no value and has not been recorded in the consolidated financial statements.

n) *Fair value measurements*

The Corporation utilizes valuation techniques that maximize the use of observable inputs and minimize the use of unobservable inputs when measuring fair value. A fair value hierarchy exists that prioritizes observable and unobservable inputs used to measure fair value. Observable inputs reflect market data obtained from independent sources, while unobservable inputs reflect the Corporation's assumptions with respect to how market participants would price an asset or liability. The fair value hierarchy includes three levels of inputs that may be used to measure fair value:

- *Level 1*: Unadjusted quoted prices in active markets for identical assets or liabilities. An active market for the asset or liability is a market in which transactions for the asset or liability occur with sufficient frequency and volume to provide pricing information on an ongoing basis;

- *Level 2*: Other than quoted prices included within Level 1 that are observable for the assets or liabilities, either directly or indirectly; and

- *Level 3*: Unobservable inputs, supported by little or no market activity, used to measure the fair value of the assets or liabilities to the extent that observable inputs are not available.

o) *Employee future benefits*

Multi-employer pension plan

The Corporation provides a pension plan for its full-time employees through the Ontario Municipal Employees Retirement System ["OMERS"]. OMERS is a multi-employer, contributory, defined benefit pension plan established in 1962 by Ontario for employees of municipalities, local boards and school boards. Both participating employers and employees are required to make plan contributions based on participating employees' contributory earnings. The OMERS plan is accounted for as a defined contribution plan where the Corporation recognizes the expense related to this plan as contributions are made. The Corporation is not responsible for any other contractual obligations other than the contributions.

As at December 31, 2011, OMERS had approximately 263,000 active members. As at June 30, 2012, approximately 1,600 members are current employees of the Corporation.

Post-retirement benefits other than pension

The Corporation has a number of unfunded benefit plans providing post-retirement benefits (excluding pension) to its employees. The Corporation pays certain medical, dental and life insurance benefits under unfunded defined benefit plans on behalf of its retired employees. The Corporation pays accumulated sick leave credits, up to certain established limits based on service, in the event of retirement, termination or death of certain employees.

The Corporation periodically measures its accumulated benefit obligation for accounting purposes as at December 31 of the applicable year. The latest actuarial valuation was performed as at January 1, 2010.

The cost of providing benefits under the defined benefit plans is determined using the projected unit credit method and based on assumptions that reflect management's best estimate. All actuarial gains and losses and prior service costs are recognized in other comprehensive income ["OCI"] as they arise and subsequently reclassified to a regulatory asset on the consolidated balance sheets. This results in the full recognition of the benefit obligation as a liability on the consolidated balance sheets.

Actuarial gains or losses are amortized into net periodic benefit cost for the current period when the net cumulative unrecognized actuarial gains or losses in the regulatory asset at the end of the previous reporting period exceed 10% of the accumulated benefit obligation at that date. These gains or losses are recognized over the expected average remaining service period of active employees participating in the plans.

The prior service costs in the regulatory asset are recognized as an expense on a straight-line basis over the average remaining service period of employees active at the date of amendment.

The effects of a curtailment loss are recognized in the consolidated statements of net income and comprehensive income when its occurrence is probable and reasonably estimable. The effects of a curtailment gain are recognized in the consolidated statements of net income and comprehensive income when the related employees terminate or the plan suspension or amendment is adopted. The effects of a settlement gain or loss are recognized in the consolidated statements of net income and comprehensive income in the period in which a settlement occurs.

p) Asset retirement obligations

The Corporation recognizes a liability for the future environmental remediation of certain properties and for future removal and handling costs for contamination in distribution equipment in service and in storage. Initially, the liability is measured at present value and the amount of the liability is added to the carrying amount of the related asset. In subsequent periods, the asset is depreciated and the liability is adjusted quarterly for the discount applied upon initial recognition of the liability and for changes in the underlying assumptions. The liability is recognized when the asset retirement obligation ["ARO"] is incurred and when the fair value is determined.

q) Customers' advance deposits

Security deposits from electricity customers are cash collections to guarantee the payment of electricity bills. The electricity customer security deposits liability includes related interest amounts owed to the customers with the debit charged to net financing charges. Deposits that are refundable upon demand are classified as a current liability.

Security deposits on Offers to Connect are cash collections from specific customers to guarantee the payment of additional costs relating to expansion projects. This liability includes related interest amounts owed to the customers with the debit charged to net financing charges. Deposits are classified as a current liability when the Corporation no longer has an unconditional right to defer payment of the liability for at least 12 months after the reporting period.

r) Income Taxes

Under the Electricity Act, the Corporation is required to make Payments In Lieu of Corporate Taxes ["PILs"] to the Ontario Electricity Financial Corporation. These payments are calculated in accordance with the *Income Tax Act* (Canada) and the *Taxation Act, 2007* (Ontario) (for years ending after 2008) or the *Corporations Tax Act* (Ontario) (for years ending prior to 2009) as modified by regulations made under the Electricity Act and related regulations. This effectively results in the Corporation paying taxes similar to what would be imposed under the federal and Ontario tax acts.

The Corporation uses the liability method of accounting for income taxes. Under the liability method, current income taxes payable are recorded based on taxable income. The Corporation recognizes deferred income tax assets and liabilities for the future tax consequences of events that have been included in the consolidated financial statements or income tax returns. Deferred income tax assets and liabilities are determined based on the difference between the carrying value of assets and liabilities on the consolidated balance sheets and their respective tax basis using the enacted tax rates by the consolidated balance sheet date in effect for the period in which the differences are expected to reverse. Tax benefits associated with income tax positions taken, or expected to be taken, in a tax return are recorded only when it is more likely than not that they will be realized, and are measured at the largest amount of the benefit that has a likelihood greater than 50 percent of being realized upon settlement. Deferred income tax assets are evaluated and if realization is not considered more likely than not, a valuation allowance is established.

ASC 980 requires the recognition of deferred income tax assets and liabilities and related regulatory liabilities and assets for the amount of deferred income taxes expected to be refunded to, or recovered from, customers in future electricity distribution rates. As at June 30, 2012, LDC recorded a deferred income tax asset and a corresponding regulatory liability of $197,566,000 with respect to its rate-regulated activities *[note 9]*.

The benefits of the refundable apprenticeship and co-operative investment tax credits ["ITC"] are credited against the related expense in the consolidated statements of net income and comprehensive income. All other types of ITCs are recorded as a reduction to income tax expense in the current period to the extent that realization of such benefit is more likely than not.

s) Use of estimates

The preparation of the Corporation's unaudited interim consolidated financial statements in accordance with US GAAP requires management to make estimates and assumptions which affect the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities at the date of the interim consolidated financial statements and the reported amounts of revenues and expenses for the period. The estimates are based on historical experience, current conditions and various other assumptions that are believed to be reasonable under the circumstances, the results of which form the basis for making judgments about the carrying values of assets and liabilities as well as identifying and assessing the accounting treatment with respect to commitments and contingencies. Significant areas requiring the use of management estimates relate to unbilled revenue, regulatory assets and liabilities, environmental liabilities and AROs, employee future benefits, and revenue recognition. Actual results could differ from those estimates, including changes as a result of future decisions made by the OEB, the Ministry of Energy, or the Ministry of Finance of Ontario ["Ministry of Finance"].

[all tabular amounts in thousands of Canadian dollars, unaudited]

t) *Future Accounting Pronouncements*

A number of new standards and interpretations are not yet effective for the period ended June 30, 2012. The Corporation continues to analyze these standards and has initially determined that the following could have a significant effect on the consolidated financial statements.

In December 2011, the FASB issued Accounting Standards Update [“ASU”] No. 2011-11, “Balance Sheet (Topic 210): *Disclosures about Offsetting Assets and Liabilities*” [“ASU 2011-11”]. The amendments require an entity to disclose both gross and net information about financial instruments and transactions eligible for offset in the consolidated balance sheets. ASU 2011-11 is effective for fiscal years, and interim periods within those years, beginning on or after January 1, 2013. Retrospective application is required. The adoption of this amendment is expected to increase disclosures related to offsetting assets and liabilities and is not expected to have an impact to the Corporation’s consolidated balance sheets.

5. INVENTORIES

Inventories consist of the following:

	June 30 2012 $	**December 31 2011 $**
Consumables, tools and other maintenance items	**1,807**	1,745
Fuses	**1,624**	1,625
Drums and reels	**876**	938
Other	**2,065**	2,583
	6,372	6,891

For the three months and the six months ended June 30, 2012, the Corporation recognized operating expenses of $1,477,000 and $3,609,000 related to inventory used to service electrical distribution assets [three months and six months ended June 30, 2011 - $1,954,000 and $4,151,000].

6. CURRENT PORTION OF OTHER ASSETS

Current portion of other assets consist of the following:

	June 30 2012 $	**December 31 2011 $**
Prepaid expenses	**6,091**	4,487
Debt issuance costs	**898**	922
	6,989	5,409

[all tabular amounts in thousands of Canadian dollars, unaudited]

7. PROPERTY, PLANT AND EQUIPMENT, NET

Property, plant and equipment consist of the following:

	June 30 2012			December 31 2011		
	Cost $	Accumulated depreciation $	Net book value $	Cost $	Accumulated depreciation $	Net book value $
Land	**16,761**	**—**	**16,761**	16,761	—	16,761
Distribution lines	**2,896,055**	**1,458,869**	**1,437,186**	2,850,401	1,441,333	1,409,068
Transformers	**661,039**	**369,035**	**292,004**	652,102	360,398	291,704
Stations	**281,385**	**141,386**	**139,999**	277,905	137,246	140,659
Meters	**241,823**	**128,992**	**112,831**	238,459	124,117	114,342
Buildings	**157,540**	**65,914**	**91,626**	154,932	62,403	92,529
Rolling stock	**75,535**	**42,646**	**32,889**	78,016	43,154	34,862
Other capital assets	**70,306**	**46,151**	**24,155**	68,802	44,108	24,694
Equipment and tools	**44,756**	**32,847**	**11,909**	44,208	31,785	12,423
Assets under capital lease	**13,605**	**2,015**	**11,590**	14,269	1,251	13,018
Computer hardware	**49,017**	**37,769**	**11,248**	44,625	35,602	9,023
Communications	**31,693**	**25,291**	**6,402**	31,537	23,912	7,625
Construction in progress	**239,783**	**—**	**239,783**	232,789	—	232,789
	4,779,298	**2,350,915**	**2,428,383**	4,704,806	2,305,309	2,399,497

For the three months and the six months ended June 30, 2012, AFUDC in the amount of $201,000 and $485,000 [three months and six months ended June 30, 2011 - $1,069,000 and $1,595,000] was capitalized to property, plant and equipment and credited to net financing charges.

As at June 30, 2012, the net book value of stranded meters related to the deployment of smart meters amounting to $18,970,000 [December 31, 2011 - $20,366,000] was included in property, plant and equipment. In the absence of rate regulation, property, plant and equipment would have been $18,970,000 lower as at June 30, 2012 [December 31, 2011 - $20,366,000 lower].

For the three months and the six months ended June 30, 2012, the Corporation recorded depreciation expense of $30,008,000 and $59,773,000 [three months and six months ended June 30, 2011 - $30,859,000 and $59,823,000] of which $491,000 and $1,010,000 [three months and six months ended June 30, 2011 - $51,000 and $96,000] related to assets under capital lease.

[all tabular amounts in thousands of Canadian dollars, unaudited]

8. INTANGIBLE ASSETS, NET

Intangible assets consist of the following:

	June 30 2012			December 31 2011		
	Cost $	Accumulated amortization $	Net book value $	Cost $	Accumulated amortization $	Net book value $
Computer software	**226,878**	**164,720**	**62,158**	222,598	154,186	68,412
Contributions	**12,280**	**1,693**	**10,587**	14,059	1,440	12,619
Software in development	**21,245**	**—**	**21,245**	15,598	—	15,598
Contributions for work in progress	**34,414**	**—**	**34,414**	16,353	—	16,353
	294,817	**166,413**	**128,404**	268,608	155,626	112,982

For the three months and the six months ended June 30, 2012, the Corporation acquired $4,132,000 and $26,209,000 of intangible assets [three months and six months ended June 30, 2011 - $11,834,000 and $29,226,000]. Contributions for work in progress relate to payments for connection projects to increase electricity distribution system capacity. All intangible assets are subject to amortization when they become available for use. Software in development and contributions for work in progress relate to assets not currently available for use and therefore are not amortized.

For the three months and the six months ended June 30, 2012, $2,821,000 and $4,281,000 of software in development was transferred to computer software [three months and six months ended June 30, 2011 - $4,330,000 and $8,883,000].

For the three months and the six months ended June 30, 2012, AFUDC in the amount of $374,000 and $643,000 [three months and six months ended June 30, 2011 - $452,000 and $892,000] was capitalized to intangible assets and credited to net financing charges.

For the three months and the six months ended June 30, 2012, the Corporation recorded amortization expense on intangible assets of $5,124,000 and $10,787,000 [three months and six months ended June 30, 2011 - $4,555,000 and $9,063,000].

As at June 30, 2012, estimated future amortization expense related to intangible assets is as follows:

	$
2012 [(1)]	9,826
2013	16,139
2014	15,657
2015	14,712
2016	11,755

[(1)] The amount disclosed represents the period July 1, 2012 to December 31, 2012.

[all tabular amounts in thousands of Canadian dollars, unaudited]

9. REGULATORY ASSETS AND LIABILITIES

Regulatory assets consist of the following:

	June 30 2012 $	December 31 2011 $ *[note 24]*
Smart meters	**58,563**	61,422
Accounting policy changes	**62,729**	64,785
Settlement variances	**13,142**	14,119
Regulatory assets recovery account	**4,669**	931
Other	**576**	1,781
	139,679	143,038
Less: Current portion of regulatory assets	**3,833**	—
Long-term portion of regulatory assets	**135,846**	143,038

Regulatory liabilities consist of the following:

	June 30 2012 $	December 31 2011 $ *[note 24]*
Deferred income taxes	**197,566**	200,436
Regulatory assets recovery account	**—**	7,293
Income and other taxes variance account	**2,381**	2,365
Other	**1,126**	1,118
	201,073	211,212
Less: Current portion of regulatory liabilities	**—**	7,293
Long-term portion of regulatory liabilities	**201,073**	203,919

For the three months and the six months ended June 30, 2012, LDC disposed of approved net regulatory liabilities amounting to $2,185,000 and $11,033,000 through permitted distribution rate adjustments [three months and six months ended June 30, 2011 - $7,393,000 and $14,518,000].

The regulatory assets and liabilities of the Corporation are as follows:

a) Smart Meters

The smart meters regulatory asset account relates to Ontario's decision to install smart meters throughout Ontario. LDC substantially completed its smart meter project as at December 31, 2010. In connection with this initiative, the OEB ordered LDC to record all expenditures and related revenues from 2008 to 2010 to a regulatory asset account and allowed LDC to keep the net book value of the stranded meters in property, plant and equipment. Effective January 1, 2011, LDC has recorded smart meter costs in property, plant and equipment and intangible assets as a regular distribution activity as directed by the OEB. LDC expects to apply to the OEB in the future for both the transfer of the 2008 to 2010 smart meter costs from regulatory assets to property, plant and equipment and intangible assets, and the transfer of the net book value of the stranded meters from property, plant and equipment to regulatory assets.

As at June 30, 2012, smart meter capital expenditures, net of accumulated depreciation, totalling $56,046,000 were recorded to regulatory assets [December 31, 2011 - $59,227,000]. These expenditures would otherwise have been recorded as property, plant and equipment and intangible assets under US GAAP for unregulated businesses. In the absence of rate regulation, property, plant and equipment and intangible assets would have been $52,529,000 and $3,517,000 higher, respectively, as at June 30, 2012 [December 31, 2011 - $54,825,000 and $4,402,000 higher, respectively].

For the three months and the six months ended June 30, 2012, smart meter depreciation expense of $1,591,000 and $3,181,000 [three months and six months ended June 30, 2011 - $1,591,000 and $3,181,000] were deferred which would have been expensed under US GAAP for unregulated businesses. In the absence of rate regulation, for the three months and the six months ended June 30, 2012, depreciation expense would have been $1,591,000 and $3,181,000 higher [three months and six months ended June 30, 2011 - $1,591,000 and $3,181,000 higher].

For the three months and the six months ended June 30, 2012, smart meter customer revenues of $1,454,000 and $2,886,000 were deferred [three months and six months ended June 30, 2011 - $1,451,000 and $2,932,000]. In the absence of rate regulation, for the three months and the six months ended June 30, 2012, revenue would have been $1,454,000 and $2,886,000 higher [three months and six months ended June 30, 2011 - $1,451,000 and $2,932,000 higher].

b) Accounting Policy Changes

This regulatory asset account relates to the accounting policy changes upon adoption of US GAAP, primarily related to the expected future electricity distribution charges to customers arising from timing differences in the recognition of actuarial losses and prior service costs of other post-retirement benefits *[note 24]*. The period in which recovery is expected cannot be determined at this time.

c) Settlement Variances

This account is comprised of the variances between amounts charged by LDC to customers, based on regulated rates, and the corresponding cost of non-competitive electricity service incurred by LDC. The settlement variances relate primarily to service charges, non-competitive electricity charges and the global adjustment. Accordingly, LDC has deferred the variances between the costs incurred and the related recoveries in accordance with the criteria set out in the accounting principles prescribed by the OEB in the AP Handbook.

The balance for settlement variances continues to be calculated and attracts carrying charges in accordance with the OEB's direction. For the three months and the six months ended June 30, 2012, settlement variances of $3,019,000 and $12,249,000 were disposed through rate adjustments [three months and six months ended June 30, 2011 - $7,270,000 and $14,914,000].

d) Deferred Income Taxes

This regulatory liability account relates to the expected future electricity distribution rate reduction for customers arising from timing differences in the recognition of deferred tax assets *[note 4[r]]*.

As at June 30, 2012, LDC recorded a deferred income tax asset and a corresponding regulatory liability of $197,566,000 [December 31, 2011 - $200,436,000] with respect to its rate-regulated activities.

[all tabular amounts in thousands of Canadian dollars, unaudited]

e) Regulatory Assets Recovery Account

The Regulatory Assets Recovery Account [“RARA”] consists of balances of regulatory assets or regulatory liabilities approved for disposition by the OEB through rate riders. The RARA is subject to carrying charges following the OEB prescribed methodology and related rates.

On April 9, 2010, the OEB approved the disposition of net regulatory liabilities of $68,140,000, consisting of credit balances for settlement variances and income and other taxes variances of $58,225,000 and $11,900,000, respectively, and intangible assets debit balance of $1,985,000, over a two-year period commencing on May 1, 2010 and ending on April 30, 2012.

On October 29, 2010, the OEB approved the disposition of regulatory assets of $5,296,000, for amounts in connection with the contact voltage remediation activities, for the period commencing on November 1, 2010 and ending on April 30, 2012.

On February 22, 2011, the OEB approved the disposition of the Late Payment Penalties Settlement regulatory asset of $7,526,000, over a 21-month period commencing on August 1, 2011 and ending on April 30, 2013.

On July 7, 2011, the OEB approved the disposition of net regulatory liabilities of $8,572,000, consisting of credit balances for settlement variances, income and other taxes variances and 2008 RARA residual of $7,460,000, $3,373,000, and $789,000, respectively, and an International Financial Reporting Standards [“IFRS”] cost debit balance of $3,050,000, over a nine-month period commencing on August 1, 2011 and ending on April 30, 2012.

f) Income and Other Taxes Variance Account

The income and other taxes variance regulatory liability account relates to the differences that have resulted from a legislative or regulatory change to the tax rates or rules assumed in the rate adjustment model. As at June 30, 2012, the balance in this account consisted of an over-recovery from customers of $2,381,000 [December 31, 2011 - $2,365,000].

10. OTHER ASSETS

Other long-term assets consist of the following:

	June 30 2012 $	December 31 2011 $
Prepaid expenses	**7,236**	7,331
Debt issuance costs	**4,586**	5,092
	11,822	12,423

11. CREDIT FACILITIES

The Corporation is a party to a revolving credit facility expiring on May 3, 2013 [“Revolving Credit Facility”], pursuant to which the Corporation may borrow up to $400,000,000, of which up to $140,000,000 is available in the form of letters of credit. Additionally, the Corporation is a party to a bilateral facility for $50,000,000 for the purpose of issuing letters of credit mainly to support LDC’s prudential requirements with the IESO.

[all tabular amounts in thousands of Canadian dollars, unaudited]

As at June 30, 2012, no amounts had been drawn under the Corporation's Revolving Credit Facility [December 31, 2011 - $nil]. As at June 30, 2012, no amounts had been drawn for working capital purposes [December 31, 2011 - $nil].

As at June 30, 2012, $45,587,000 had been drawn on the bilateral facility [December 31, 2011 - $45,077,000].

12. RESTRUCTURING

In the first quarter of 2012, the Corporation's Board of Directors approved a workforce restructuring program aimed at reducing operating expenditures for LDC. The program was approved following the decision by the OEB to deny the request of LDC to set its electricity distribution rates for 2012, 2013 and 2014 under the COS framework. In preparing its revised application using the IRM framework, LDC concluded that significant cost reductions were necessary to manage its business within the confines of the expected allowed electricity distribution rates provided by the IRM framework *[note 3[a]]*. The main component of these operating cost reduction initiatives was a workforce restructuring program, which included the severance of management employees and a voluntary exit incentive program for targeted unionized positions.

For the three months and the six months ended June 30, 2012, the costs incurred as a result of these operating cost reduction initiatives amounted to $nil and $27,796,000 and were comprised of ongoing termination charges of $nil and $23,668,000 and one-time termination incentive charges of $nil and $4,128,000, of which $19,264,000 remains unpaid as at June 30, 2012.

13. DEBENTURES

Debentures consist of the following:

	June 30 2012 $	December 31 2011 $
Senior unsecured debentures		
Series 1 – 6.11% due May 7, 2013	**224,984**	224,976
Series 2 – 5.15% due November 14, 2017	**249,847**	249,835
Series 3 – 4.49% due November 12, 2019	**249,953**	249,951
Series 5 – 6.11% due May 6, 2013	**245,057**	245,057
Series 6 – 5.54% due May 21, 2040	**199,858**	199,857
Series 7 – 3.54% due November 18, 2021	**299,858**	299,851
Total debentures	**1,469,557**	1,469,527
Less: Current portion of debentures	**470,041**	—
Long-term portion of debentures	**999,516**	1,469,527

All debentures of the Corporation rank equally.

The Corporation may redeem some or all of the debentures at any time prior to maturity at a price equal to the greater of the Canada Yield Price (determined in accordance with the terms of the debentures) and par, plus accrued and unpaid interest up to and excluding the date fixed for redemption. Also, the Corporation may, at any time and from time to time, purchase debentures for cancellation, in the open market, by tender or by private contract, at any price. The debentures contain certain covenants which, subject to certain exceptions, restrict the ability of the

[all tabular amounts in thousands of Canadian dollars, unaudited]

Corporation and LDC to create security interests, incur additional indebtedness or dispose of all or substantially all of their assets.

14. EMPLOYEE FUTURE BENEFITS

a) Pension

The Corporation provides a pension plan for its full time employees through OMERS. Details of the plan are as follows:

Pension Plan, Employer Identification Number / Pension Number	Funded Status as at December 31, 2011	Contributions			
		Three months ended June 30		Six months ended June 30	
		2012 $	2011 $	2012 $	2011 $
OMERS, 564191	89%	**3,703**	3,086	**8,888**	7,290

The Corporation's contributions do not represent more than five percent of total contributions to the plan as indicated in OMERS's most recently available annual report for the year ended December 31, 2011. As of the end of the year, no funding improvement plan or rehabilitation plan had been implemented or was pending.

For 2012, OMERS contribution rates are 8.3% up to the year's maximum pensionable earnings ["YMPE"] and 12.8% over YMPE for normal retirement age ["NRA"] of 65 [2011 - 7.4% up to YMPE and 10.7% over YMPE for NRA of 65].

b) Post-retirement benefits other than pension

The components of net periodic benefit cost are:

	Three months ended June 30		Six months ended June 30	
	2012 $	2011 $	2012 $	2011 $
Service cost	**1,288**	977	**2,576**	1,954
Interest cost	**2,915**	2,877	**5,829**	5,754
Amortization of net actuarial loss	**761**	158	**1,523**	316
Amortization of prior service cost	**267**	273	**533**	546
Net periodic benefit cost	**5,231**	4,285	**10,461**	8,570
Capitalized as part of property, plant and equipment	**1,875**	1,755	**3,409**	3,299
Charged to operations	**3,356**	2,530	**7,052**	5,271

[all tabular amounts in thousands of Canadian dollars, unaudited]

15. ASSET RETIREMENT OBLIGATIONS

The reconciliation between the opening and closing ARO liability balances is as follows:

	June 30 2012 $	December 31 2011 $
Balance, beginning of period	**4,902**	5,005
ARO liabilities settled in the period	**(127)**	(688)
Accretion expense	**87**	173
Revision in estimated cash flows	**58**	412
Balance, end of period	**4,920**	4,902

16. FINANCIAL INSTRUMENTS

a) *Recognition and measurement*

The carrying value and fair value of the Corporation's financial instruments consist of the following:

	June 30 2012 $		December 31 2011 $	
	Carrying value	**Fair value (1)**	**Carrying value**	**Fair value (1)**
Cash and cash equivalents	**120,831**	**120,831**	154,256	154,256
Investments	**—**	**—**	34,002	34,002
Accounts receivable, net of allowance for doubtful accounts	**192,383**	**192,383**	183,272	183,272
Unbilled revenue	**272,849**	**272,849**	262,058	262,058
Accounts payable and accrued liabilities	**396,890**	**396,890**	412,412	412,412
Obligations under capital lease	**12,438**	**12,438**	13,172	13,172
Customers' advance deposits	**57,641**	**57,641**	56,038	56,038
Senior unsecured debentures				
Series 1 – 6.11% due May 7, 2013	**224,984**	**234,157**	224,976	238,359
Series 2 – 5.15% due November 14, 2017	**249,847**	**284,638**	249,835	284,126
Series 3 – 4.49% due November 12, 2019	**249,953**	**279,831**	249,951	275,575
Series 5 – 6.11% due May 6, 2013	**245,057**	**255,026**	245,057	259,578
Series 6 – 5.54% due May 21, 2040	**199,858**	**250,215**	199,857	245,096
Series 7 – 3.54% due November 18, 2021	**299,858**	**313,528**	299,851	306,696

(1) The fair value measurement of financial instruments recorded at amortized cost for which the fair value has been disclosed, including obligations under capital lease, are included in Level 2 of the fair value hierarchy.

b) *Financial Risks*

The following is a discussion of financial risks and related mitigation strategies that have been identified by the Corporation for financial instruments. This is not an exhaustive list of all risks, nor will the mitigation strategies eliminate all risks listed.

[all tabular amounts in thousands of Canadian dollars, unaudited]

The Corporation's financial activities provide for a variety of financial risks, particularly credit risk, interest rate risk and liquidity risk.

Credit risk

The Corporation is exposed to credit risk from financial instruments as a result of the risk of counterparties defaulting on their obligations. The Corporation monitors and limits its exposure to credit risk on a continuous basis.

The Corporation's credit risk associated with accounts receivable is primarily related to electricity bill payments from LDC customers. LDC has approximately 712,000 customers, the majority of which are residential. LDC collects security deposits from customers in accordance with direction provided by the OEB. As at June 30, 2012, LDC held security deposits in the amount of $57,641,000 [December 31, 2011 - $56,038,000].

Credit risk associated with accounts receivable is as follows:

	June 30 2012 $	December 31 2011 $
Total accounts receivable	**203,146**	196,259
Less: Allowance for doubtful accounts	**(10,763)**	(12,987)
Total accounts receivable, net	**192,383**	183,272
Of which:		
Outstanding for not more than 30 days	**168,369**	155,274
Outstanding for more than 30 days and not more than 120 days	**20,328**	24,777
Outstanding for more than 120 days	**14,449**	16,208
Less: Allowance for doubtful accounts	**(10,763)**	(12,987)
Total accounts receivable, net	**192,383**	183,272

Unbilled revenue represents amounts for which the Corporation has a contractual right to receive cash through future billings and are unbilled at period-end. As at June 30, 2012, total unbilled revenue was $272,849,000 [December 31, 2011 - $262,058,000]. Unbilled revenue is considered current.

As at June 30, 2012, there were no significant concentrations of credit risk with respect to any class of financial assets or counterparties. The Corporation's maximum exposure to credit risk is equal to the carrying value of its financial assets.

Interest rate risk

The Corporation is exposed to interest rate risk through holding certain financial instruments, and short-term borrowings under the Corporation's Revolving Credit Facility *[note 11]* may expose the Corporation to fluctuations in short-term interest rates. The Corporation attempts to minimize interest rate risk by issuing long-term fixed rate debt, and by extending or shortening the term of its short-term money market investments by assessing the monetary policy stance of the Bank of Canada, while ensuring that all payment obligations are met on an ongoing basis.

Under an IRM framework, the Corporation's allowed return on equity will be fixed for all years that fall under the IRM period. Since the return on equity is fixed, a fluctuation of interest rates will not affect the return on equity and therefore will not require a hypothetical sensitivity analysis.

[all tabular amounts in thousands of Canadian dollars, unaudited]

Liquidity risk

The Corporation is exposed to liquidity risk related to commitments associated with financial instruments. The Corporation monitors and manages its liquidity risk to ensure access to sufficient funds to meet operational and investing requirements. The Corporation's objective is to ensure that sufficient liquidity is on hand to meet obligations as they fall due while minimizing net financing charges. The Corporation has access to credit facilities and monitors cash balances daily to ensure that sufficient levels of liquidity are on hand to meet financial commitments as they come due. Liquidity risks associated with financial commitments are as follows:

June 30, 2012	Due within 1 year $	Due between 1 year and 5 years $	Due after 5 years $
Financial liabilities			
Accounts payable and accrued liabilities	**396,890**	**—**	**—**
Obligations under capital lease	**2,407**	**9,519**	**2,364**
Senior unsecured debentures			
Series 1 – 6.11% due May 7, 2013	**225,000**	**—**	**—**
Series 2 – 5.15% due November 14, 2017	**—**	**—**	**250,000**
Series 3 – 4.49% due November 12, 2019	**—**	**—**	**250,000**
Series 5 – 6.11% due May 6, 2013	**245,057**	**—**	**—**
Series 6 – 5.54% due May 21, 2040	**—**	**—**	**200,000**
Series 7 – 3.54% due November 18, 2021	**—**	**—**	**300,000**
Interest payments on debentures	**74,520**	**183,200**	**335,322**
	943,874	**192,719**	**1,337,686**

Hedging and Derivative risk

As at June 30, 2012 and December 31, 2011, the Corporation had not entered into hedging and derivative financial instruments.

Foreign exchange risk

As at June 30, 2012, the Corporation had limited exposure to the changing values of foreign currencies. While the Corporation purchases goods and services which are payable in US dollars, and purchases US currency to meet the related payables commitments when required, the impact of these transactions is not material to the interim consolidated financial statements.

17. FINANCIAL GUARANTEES

The City has authorized the Corporation to provide financial assistance to its subsidiaries, and LDC to provide financial assistance to other subsidiaries of the Corporation, in the form of letters of credit and guarantees, for the purpose of enabling them to carry on their businesses, up to an aggregate amount of $500,000,000.

18. INCOME TAXES

The Corporation's effective tax rate for the three months and the six months ended June 30, 2012 was 0.39% and 0.56% [three months and six months ended June 30, 2011 - (12.11)% and (0.57)%]. The effective tax rate for the three months and the six months ended June 30, 2012 was higher than the three months and the six months ended June 30, 2011, primarily due to recording deferred income taxes against regulatory assets and liabilities.

[all tabular amounts in thousands of Canadian dollars, unaudited]

Income tax expense for the three months and the six months ended June 30, 2012 was $161,000 [income tax recovery for three months and six months ended June 30, 2011 - $2,622,000 and $284,000]. The change in income tax expense between the three months and the six months ended June 30, 2012 and June 30, 2011 was primarily due to recording deferred income taxes against regulatory assets and liabilities.

19. SHARE CAPITAL

Share capital consists of the following:

	June 30 2012 $	December 31 2011 $
Authorized		
The authorized share capital of the Corporation consists of an unlimited number of common shares		
Issued and outstanding		
1,000 common shares	**567,817**	567,817

Dividends

The shareholder direction adopted by the City with respect to the Corporation provides that the Board of Directors of the Corporation will use its best efforts to ensure that the Corporation meets certain financial performance standards, including those relating to the credit rating and dividends.

Subject to applicable law, the shareholder direction provides that the Corporation will pay dividends to the City each year amounting to the greater of $25,000,000 or 50% of the Corporation's consolidated net income for the year. The dividends are not cumulative and are payable as follows:

[i] $6,000,000 on the last day of each of the first three fiscal quarters during the year;

[ii] $7,000,000 on the last day of the fiscal year; and

[iii] the amount, if any, by which 50% of the Corporation's annual consolidated net income for the year exceeds $25,000,000, within ten days after the approval of the Corporation's audited consolidated financial statements for the year by the Board of Directors of the Corporation.

On March 2, 2012, the Board of Directors of the Corporation declared dividends in the amount of $28,966,000. The dividends were comprised of $22,966,000 with respect to net income for the year ended December 31, 2011, which was paid to the City on March 12, 2012, and $6,000,000 with respect to the first quarter of 2012, which was paid to the City on March 30, 2012.

On May 17, 2012, the Board of Directors of the Corporation declared a dividend in the amount of $6,000,000 with respect to the second quarter of 2012, which was paid to the City on June 29, 2012.

[all tabular amounts in thousands of Canadian dollars, unaudited]

20. RELATED PARTIES

For the Corporation, transactions with related parties include transactions with the City. All transactions with the City are conducted at prevailing market prices and normal trade terms.

Transactions with Related Parties Summary	Three months ended June 30		Six months ended June 30	
	2012 $	2011 $	2012 $	2011 $
Revenues	**37,812**	36,825	**78,227**	75,152
Operating expenses and capital expenditures	**6,993**	5,024	**12,042**	9,336
Dividends	**6,000**	6,000	**34,966**	20,063

Transactions with Related Parties Summary	June 30 2012 $	December 31 2011 $
Accounts receivable	**8,273**	8,412
Unbilled revenue	**9,006**	8,692
Other assets	**7,430**	7,279
Accounts payable and accrued liabilities	**26,101**	25,085
Advance deposits	**8,754**	8,714

Revenues represent amounts charged to the City primarily for electricity and street lighting services. Operating expenses and capital expenditures represent amounts charged by the City for purchased road cut repairs, property taxes and other services. Dividends represent dividends paid to the City *[note 19]*.

Accounts receivable represent receivables from the City primarily for street lighting, electricity and other services. Unbilled revenue represents receivables from the City related to the provision of electricity and other services provided and not yet billed. Other assets represent amounts for prepaid land leases from the City. Accounts payable and accrued liabilities represent amounts payable to the City relating to road cut repairs, property taxes and other services, as well as funds received from the City for the construction of electricity distribution assets. Advance deposits represent funds received from the City for future expansion projects.

[all tabular amounts in thousands of Canadian dollars, unaudited]

21. COMMITMENTS

Operating lease obligations and future commitments

As at June 30, 2012, the future minimum annual lease payments under property and equipment operating leases and future commitments with remaining terms from one to five years and thereafter were as follows:

	$
2012 [(1)]	**3,276**
2013	**23,007**
2014	**7,635**
2015	**6,670**
2016	**6,479**
Thereafter	**3,478**
Total amount of future minimum payments [(2)]	**50,545**

(1) The amount disclosed represents the balance due over the period July 1, 2012 to December 31, 2012.
(2) Refer to note 16 for repayments of senior unsecured debentures.

Capital lease obligations

As at June 30, 2012, the future minimum annual lease payments under capital leases with remaining lease terms from one to five years and thereafter were as follows:

	$
2012 [(1)]	**1,204**
2013	**2,406**
2014	**2,393**
2015	**2,376**
2016	**2,364**
Thereafter	**3,547**
Total amount of future minimum lease payments	**14,290**
Less: interest and executory costs	**1,852**
	12,438
Current portion included in Other liabilities	**1,862**
Long-term portion included in Other liabilities	**10,576**

(1) The amount disclosed represents the balance due over the period July 1, 2012 to December 31, 2012.

22. CONTINGENCIES

a) Legal Proceedings

In the ordinary course of business, the Corporation is subject to various litigation and claims with customers, suppliers, former employees and other parties. On an ongoing basis, the Corporation assesses the likelihood of any adverse judgments or outcomes as well as potential ranges of probable costs and losses. A determination of the provision required, if any, for these contingencies is made after an analysis of each individual issue. The provision may change in the future due to new developments in each matter or changes in approach, such as a change in settlement strategy. The Corporation and its subsidiaries are subject to various legal actions that arise in the normal course of business and if damages were awarded under these actions, the Corporation and its subsidiaries would make a claim under their liability insurance which the Corporation believes would cover any damages which may become payable by the Corporation and its subsidiaries in connection with these actions.

Christian Helm Class Action

On December 6, 2010, a statement of claim in a proposed class action was issued against LDC. The claim sought general and special damages in the amount of $100,000,000 for disgorgement of unjust gains allegedly resulting from the receipt of interest on overdue accounts in contravention of the *Interest Act* (Canada). On April 30, 2012, a settlement reached by the parties was approved by Order of the Ontario Superior Court of Justice. Pursuant to the terms of the Order, LDC was required to pay the amount of $5,836,000 plus costs in settlement of all claims, substantially all of which has been paid as at June 30, 2012. The Corporation accrued a liability to cover the expected settlement in 2010. The action has been dismissed, and the claims by all class members have been released.

2 Secord Avenue

An action was commenced against LDC in September 2008 in the Ontario Superior Court of Justice under the *Class Proceedings Act, 1992* (Ontario) ["Class Proceedings Act"] seeking damages in the amount of $30,000,000 as compensation for damages allegedly suffered as a result of a fire and explosion in an underground vault at 2 Secord Avenue on July 20, 2008. This action is at a preliminary stage. The statement of claim has been served on LDC, a statement of defence and third party claim have been served by LDC and a third party defence and counterclaim against LDC seeking damages in the amount of $51,000,000 have been filed. A certification order has been issued. Affidavits of documents have been produced by LDC to the other parties and examinations for discovery have commenced and are continuing. Given the preliminary status of this action, it is not possible to reasonably quantify the effect, if any, of this action on the financial performance of the Corporation. If damages were awarded, LDC would make a claim under its liability insurance which the Corporation believes would cover any damages which may become payable by LDC in connection with the action.

On December 20, 2010, LDC was served with a statement of claim by the City seeking damages in the amount of $2,000,000 as a result of the fire at 2 Secord Avenue. A statement of defence and a third party claim have been served. Given the preliminary status of this action, it is not possible to reasonably quantify the effect, if any, of this action on the financial performance of the Corporation. If damages were awarded, LDC would make a claim under its liability insurance which the Corporation believes would cover any damages which may become payable by LDC in connection with the action.

On January 24, 2012, by order of the court the above actions and a smaller non-class action commenced in April 2009 involving the same incident will be tried at the same time or consecutively.

2369 Lakeshore Boulevard West

A third party action was commenced against LDC in October 2009 in the Ontario Superior Court of Justice under the Class Proceedings Act seeking damages in the amount of $30,000,000 as compensation for damages allegedly suffered as a result of a fire in the electrical room at 2369 Lakeshore Boulevard West on March 19, 2009. Subsequently, in March 2010, the plaintiff in the main action amended its statement of claim to add LDC as a defendant. The plaintiff in the main action seeks damages in the amount of $10,000,000 from LDC. Both actions are at a preliminary stage and the certification hearing is scheduled for September 2012. Statements of defence to the main action and to the third party claim have not been filed. Accordingly, given the preliminary status of these actions, it is not possible at this time to reasonably quantify the effect, if any, of these actions on the financial performance of the Corporation. If damages were awarded, LDC would make a claim under its liability insurance which the Corporation believes would cover any damages which may become payable by LDC in connection with these actions.

Another third party action was commenced against LDC in October 2009 in the Ontario Superior Court of Justice seeking damages in the amount of $30,000,000 as compensation for damages allegedly suffered as a result of the fire at 2369 Lakeshore Boulevard West. Subsequently, in March 2010, the plaintiff in the main action amended its statement of claim to add LDC as a defendant. The plaintiff in the main action seeks damages in the amount of $400,000 from LDC. LDC has filed a statement of defence, crossclaim and counterclaim. Examinations for discovery have not taken place, notwithstanding a court ordered timetable to have them completed by February 29, 2012. Accordingly, given the preliminary status of these actions, it is not possible at this time to reasonably quantify the effect, if any, of these actions on the financial performance of the Corporation. If damages were awarded, LDC would make a claim under its liability insurance which the Corporation believes would cover any damages which may become payable by LDC in connection with these actions.

On August 29, 2011, LDC was served with a statement of claim by the owner of the building and the property management company for the building seeking damages in the amount of $2,000,000 as a result of the fire at 2369 Lakeshore Boulevard West. LDC has filed a statement of defence and counterclaim. Given the preliminary status of this action, it is not possible to reasonably quantify the effect, if any, of this action on the financial performance of the Corporation. If damages were awarded, LDC would make a claim under its liability insurance which the Corporation believes would cover any damages which may become payable by LDC in connection with the action.

b) OEB PILs Proceeding

The OEB conducted a review of the PILs variances accumulated in regulatory variance accounts for the period from October 1, 2001 to April 30, 2006 for certain Municipal Electricity Utilities ["MEUs"]. On June 24, 2011, the OEB issued its decision for these MEUs and provided guidelines for the calculation and further disposition of the balances accumulated in the PILs regulatory variance accounts. The OEB has issued interrogatories and decisions for other MEUs subsequent to its previous decision.

LDC has reviewed the balances of its PILs regulatory variance accounts and applied the guidelines provided by the OEB. As at June 30, 2012, LDC estimated its liability at approximately $6,641,000. This balance has been recorded in the Corporation's interim consolidated financial statements. LDC has applied for disposition of the balance as part of its pending IRM application filed on May 10, 2012. The amount to be approved by the OEB will be based on the OEB's interpretation and application of its guidelines and the final balance which is yet to be approved by the OEB could differ materially from LDC's estimation of its liability.

c) Payments in Lieu of Additional Municipal and School Taxes

The Ministry of Finance had issued assessments in respect of payments in lieu of additional municipal and school taxes under section 92 of the Electricity Act that were in excess of the amounts LDC believed were payable. The dispute arose as a result of inaccurate information incorporated into Ontario Regulation 224/00. The Corporation worked with the Ministry of Finance to resolve this issue, and as a result the Ministry of Finance issued Ontario Regulation 423/11 on August 31, 2011. The new regulation revoked Ontario Regulation 224/00 and corrected inaccurate information retroactively to 1999.

In May 2012, the Ministry of Finance completed its reassessment as a consequence of the change in regulation. The impact of the reassessment issued was favourable to the Corporation.

23. NET INCOME PER SHARE

The weighted daily average number of shares outstanding for the three months and the six months ended June 30, 2012 was 1,000 [three months and six months ended June 30, 2011 - 1,000]. Basic and fully diluted net income per share was determined by dividing the net income for the period by the weighted daily average number of shares outstanding.

24. US GAAP TRANSITION

Publicly accountable enterprises in Canada were required to adopt IFRS for interim and annual reporting purposes for fiscal years beginning on or after January 1, 2011. On September 10, 2010, the Accounting Standards Board granted an optional one-year deferral for IFRS adoption for entities subject to rate regulation. The Corporation elected to take the optional one-year deferral of its adoption of IFRS. In the absence of a definitive plan to consider the issuance of a RRA standard by the International Accounting Standards Board, the Corporation decided to evaluate the option of adopting US GAAP effective January 1, 2012 as an alternative to IFRS. On August 26, 2011, the Board of Directors of the Corporation approved the adoption of US GAAP for financial reporting purposes for the year beginning on January 1, 2012.

The accounting policies set out in note 4 have been applied consistently in preparing the interim consolidated financial statements for the six months ended June 30, 2012 and the comparative periods.

The Corporation has adjusted amounts reported previously in its interim and annual consolidated financial statements prepared in accordance with Canadian GAAP. For reporting purposes, the transition date to US GAAP is January 1, 2011, which is the commencement of the 2011 interim comparative period to the Corporation's 2012 interim consolidated financial statements. An explanation of how the transition from Canadian GAAP to US GAAP has affected the Corporation's interim consolidated financial statements is set out in the following tables and accompanying notes.

The reconciliation of the January 1, 2011 consolidated balance sheet from Canadian GAAP to US GAAP is as follows:

CONSOLIDATED BALANCE SHEET

[in thousands of Canadian dollars]

As at January 1, 2011	Notes	Canadian GAAP $	Transitional Adjustments $	US GAAP $
ASSETS				
Current				
Regulatory assets	A	—	3,555	**3,555**
Other	B	805,310	718	**806,028**
Total current assets		805,310	4,273	**809,583**
Regulatory assets	A	85,113	29,224	**114,337**
Other	B	2,448,191	4,132	**2,452,323**
Total assets		3,338,614	37,629	**3,376,243**
LIABILITIES AND SHAREHOLDER'S EQUITY				
Current				
Customers' advance deposits	C	—	50,630	**50,630**
Post-retirement benefits	A	—	7,415	**7,415**
Regulatory liabilities	A	—	36,654	**36,654**
Other	C	639,751	(18,790)	**620,961**
Total current liabilities		639,751	75,909	**715,660**
Customers' advance deposits	C	45,462	(31,840)	**13,622**
Debentures	B	1,164,780	4,850	**1,169,630**
Post-retirement benefits	A	169,897	22,715	**192,612**
Regulatory liabilities	A	273,706	(34,005)	**239,701**
Other		5,639	—	**5,639**
Total liabilities		2,299,235	37,629	**2,336,864**
Total shareholder's equity		1,039,379	—	**1,039,379**
Total liabilities and shareholder's equity		3,338,614	37,629	**3,376,243**

The reconciliation of the December 31, 2011 consolidated balance sheet from Canadian GAAP to US GAAP is as follows:

CONSOLIDATED BALANCE SHEET

[in thousands of Canadian dollars]

As at December 31, 2011	Notes	Canadian GAAP $	Transitional Adjustments $	US GAAP $
ASSETS				
Current				
Other	B	656,278	922	**657,200**
Total current assets		656,278	922	**657,200**
Regulatory assets	A	77,322	65,716	**143,038**
Other	B	2,722,177	5,092	**2,727,269**
Total assets		3,455,777	71,730	**3,527,507**
LIABILITIES AND SHAREHOLDER'S EQUITY				
Current				
Customers' advance deposits	C	—	40,238	**40,238**
Post-retirement benefits	A	—	7,915	**7,915**
Regulatory liabilities	A	—	7,293	**7,293**
Other	C	448,061	(20,108)	**427,953**
Total current liabilities		448,061	35,338	**483,399**
Customers' advance deposits	C	35,930	(20,130)	**15,800**
Debentures	B	1,463,514	6,013	**1,469,527**
Post-retirement benefits	A	179,541	56,870	**236,411**
Regulatory liabilities	A	210,280	(6,361)	**203,919**
Other		16,203	—	**16,203**
Total liabilities		2,353,529	71,730	**2,425,259**
Total shareholder's equity		1,102,248	—	**1,102,248**
Total liabilities and shareholder's equity		3,455,777	71,730	**3,527,507**

The reconciliation of net income from Canadian GAAP to US GAAP for the three months and the six months ended June 30, 2011 are as follows:

RECONCILIATION OF NET INCOME FROM CANADIAN GAAP TO US GAAP

[in thousands of Canadian dollars]

	Notes	Three months ended June 30 2011 $	Six months ended June 30 2011 $
Net income, Canadian GAAP		24,270	49,722
Revenues	D	2,859	5,705
Purchased power and other	D	488	934
Operating expenses	D, E	(5,870)	(9,162)
Income tax recovery	E	2,523	2,523
Net income, US GAAP		**24,270**	**49,722**

Notes to the transitional adjustments

A. Post-retirement benefits

Under Canadian GAAP, unamortized actuarial gains and losses and unamortized prior service costs are not recorded on the consolidated balance sheets. Under US GAAP, all actuarial gains and losses and prior service costs are fully recognized in OCI in the period in which they arise and are presented within equity as Accumulated Other Comprehensive Income ["AOCI"]. Due to the rate-regulated nature of the Corporation's business, the impact to AOCI on transition and the impact to OCI on a go-forward basis will be reclassified to a regulatory asset account *[note 9[b]]*. This reclassification results in the full recognition of the benefit obligation as a liability on the Corporation's consolidated balance sheets and no balance reported in OCI and AOCI. A portion of the benefit obligation will also be presented as a current liability on the consolidated balance sheets. The current portion is the amount by which the actuarial present value of benefits included in the benefit obligation is payable in the next 12 months.

B. Debt issuance costs

Under Canadian GAAP, debt issuance costs are netted against the principal balance of the related debenture. Under US GAAP, debt issuance costs are recognized as deferred charges. This presentation difference results in an increase in other current assets and other assets and an offsetting increase to debentures.

C. Customers' advance deposits

Under US GAAP, deposits that are due on demand or will be due on demand within one year from the end of the reporting period have been reclassified as current liabilities.

D. Demand billable income and expenses

Under US GAAP, associated costs related to demand billable income have been reclassified on the consolidated statements of net income and comprehensive income. There is no impact to the overall net income.

E. Income tax recovery

Under Canadian GAAP, all ITCs are recognized as a reduction of the related expenditure. Under US GAAP, the benefits of the refundable apprenticeship and co-operative ITCs are recognized as a reduction of the related expenditure. All other ITCs are recorded as a reduction of income tax expense in the current period to the extent that realization of such benefits is more likely than not.

25. SEASONAL OPERATIONS

The Corporation's quarterly results are impacted by changes in revenues resulting from variations in seasonal weather conditions, the fluctuations in electricity prices, and the timing and recognition of regulatory decisions. The Corporation's revenues tend to be higher in the first and third quarters of a year as a result of higher energy consumption for winter heating in the first quarter and air conditioning/cooling in the third quarter.

26. SUBSEQUENT EVENTS

The Corporation has evaluated the events and transactions occurring after the consolidated balance sheet date through August 17, 2012 when the Corporation's interim consolidated financial statements were available to be issued after the approval by the Corporation's Board of Directors, and identified the following event and transaction which required recognition in the interim consolidated financial statements and/or disclosure in the notes to the interim consolidated financial statements:

Dividends

On August 17, 2012, the Board of Directors of the Corporation declared a dividend in the amount of $6,000,000 with respect to the third quarter of 2012. The dividend is payable on September 28, 2012.

MANAGEMENT'S DISCUSSION AND ANALYSIS
JUNE 30, 2012

TORONTO HYDRO CORPORATION

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS FOR THE INTERIM PERIOD ENDED JUNE 30, 2012

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Forward-Looking Information

Toronto Hydro Corporation (the "Corporation") includes forward-looking information in its Management's Discussion and Analysis ("MD&A") within the meaning of applicable securities laws in Canada ("forward-looking information"). The purpose of the forward-looking information is to provide management's expectations regarding the Corporation's future results of operations, performance, business prospects and opportunities and may not be appropriate for other purposes. All forward-looking information is given pursuant to the "safe harbour" provisions of applicable Canadian securities legislation. The words "anticipates", "believes", "budgets", "could", "estimates", "expects", "forecasts", "intends", "may", "might", "plans", "projects", "schedule", "should", "will", "would" and similar expressions are often intended to identify forward-looking information, although not all forward-looking information contains these identifying words. The forward-looking information reflects management's current beliefs and is based on information currently available to the Corporation's management.

The forward-looking information in the MD&A includes, but is not limited to, statements regarding Toronto Hydro-Electric System Limited's ("LDC") distribution revenue, the outcome of outstanding rate applications and other proceedings before the Ontario Energy Board ("OEB"), the Corporation's plans to borrow funds to repay maturing debentures and to finance the investment in LDC's infrastructure, LDC's Conservation and Demand Management ("CDM") programs, the expected results of legal proceedings, market volatility on the Corporation's consolidated results of operations, performance, business prospects and opportunities, the effect of changes in interest rates on future revenue requirements and the changes in accounting estimates. The statements that make up the forward-looking information are based on assumptions that include, but are not limited to, the future course of the economy and financial markets, the receipt of applicable regulatory approvals and requested rate orders, the receipt of favourable judgments, the level of interest rates and the Corporation's ability to borrow.

The forward-looking information is subject to risks, uncertainties and other factors that could cause actual results to differ materially from historical results or results anticipated by the forward-looking information. The factors which could cause results or events to differ from current expectations include, but are not limited to, market liquidity and the quality of the underlying assets and financial instruments, the timing and extent of changes in prevailing interest rates, inflation levels, legislative, judicial and regulatory developments that could affect revenues and the results of borrowing efforts.

All forward-looking information in the MD&A is qualified in its entirety by the above cautionary statements and, except as required by law, the Corporation undertakes no obligation to revise or update any forward-looking information as a result of new information, future events or otherwise after the date hereof.

Introduction

The following MD&A should be read in conjunction with:

- the unaudited interim consolidated financial statements and accompanying notes of the Corporation as at and for the three-month period and six-month period ended June 30, 2012 (the "Interim Consolidated Financial Statements");

- the audited consolidated financial statements and accompanying notes of the Corporation as at and for the year ended December 31, 2011 (the "Annual Consolidated Financial Statements"); and

- the Corporation's MD&A for the year ended December 31, 2011 (including the sections entitled "Electricity Distribution – Industry Overview", "Summary of Quarterly Results", "Liquidity and Capital Resources", "Corporate Developments", "Legal Proceedings", "Share Capital", "Transactions with Related Parties", "Risk Factors", "Critical Accounting Estimates", "Changes in Accounting Estimates", and "Future Accounting Pronouncements" which remain substantially unchanged as at the date hereof except as noted below or as updated by the Interim Consolidated Financial Statements).

Copies of these documents are available on the Canadian Securities Administrators' web site at www.sedar.com.

Effective January 1, 2012, the Corporation's Interim Consolidated Financial Statements have been prepared in accordance with United States Generally Accepted Accounting Principles ("US GAAP"), including the accounting principles prescribed by the OEB in the "Accounting Procedures Handbook for Electricity Distributors" (the "AP Handbook") and are presented in Canadian dollars (see "Significant Accounting Policies" below). The Corporation's Annual and Interim Consolidated Financial Statements were prepared in accordance with Canadian Generally Accepted Accounting Principles ("Canadian GAAP") until December 31, 2011. All comparative consolidated financial statements have been adjusted retroactively from the consolidated financial statements previously presented to conform to the presentation of the Corporation's 2012 interim consolidated financial statements prepared in accordance with US GAAP.

Business of Toronto Hydro Corporation

The Corporation is a holding company which wholly-owns two subsidiaries:

- *LDC* - which distributes electricity and engages in CDM activities; and

- *Toronto Hydro Energy Services Inc.* ("TH Energy") - which provides street lighting services.

The principal business of the Corporation and its subsidiaries is the distribution of electricity by LDC. LDC owns and operates an electricity distribution system, which delivers electricity to approximately 712,000 customers located in the City of Toronto (the "City"). LDC is the largest municipal electricity distribution company in Canada and distributes approximately 18% of the electricity consumed in the Province of Ontario ("Ontario"). The business of LDC is regulated by the OEB which has broad powers relating to licensing, standards of conduct and service and the regulation of electricity distribution rates charged by LDC and other electricity distributors in Ontario. See note 3 to the Interim Consolidated Financial Statements.

The sole shareholder of the Corporation is the City.

Executive Summary

- Net income for the three months and six months ended June 30, 2012 was $41.5 million and $28.7 million, compared to net income of $24.3 million and $49.7 million for the comparable periods in 2011;
- capital expenditures were $49.9 million and $115.3 million for the three months and six months ended June 30, 2012, compared to $104.8 million and $205.2 million for the comparable periods in 2011, with the decrease primarily related to uncertainty regarding the electricity distribution rates of LDC for 2012;
- on May 10, 2012, LDC filed its application to set electricity distribution rates for 2012, 2013 and 2014 under the Incentive Regulation Mechanism ("IRM") framework; and
- effective January 1, 2012, the Corporation's Interim Consolidated Financial Statements have been prepared in accordance with US GAAP.

Selected Interim Consolidated Financial Data

Interim Consolidated Statements of Net Income and Comprehensive Income
Three months ended June 30
(in thousands of Canadian dollars, except for per share amounts, unaudited)

	2012 $	2011 $	Change $	Change %
Revenues	709,700	686,646	23,054	3.4
Costs				
Purchased power	565,053	547,660	17,393	3.2
Operating expenses	49,646	65,611	(15,965)	(24.3)
Depreciation and amortization	35,132	35,414	(282)	(0.8)
	649,831	648,685	1,146	0.2
Income before the following:	59,869	37,961	21,908	57.7
Net financing charges	(18,170)	(18,066)	(104)	(0.6)
Gain on disposals of property, plant and equipment ("PP&E")	-	1,753	(1,753)	(100.0)
Income before income taxes	41,699	21,648	20,051	92.6
Income tax expense (recovery)	161	(2,622)	2,783	(106.1)
Net income and comprehensive income	41,538	24,270	17,268	71.1
Basic and fully diluted net income per share	41,538	24,270	17,268	71.1

Interim Consolidated Statements of Net Income and Comprehensive Income
Six months ended June 30
(in thousands of Canadian dollars, except for per share amounts, unaudited)

	2012 $	2011 $	Change $	Change %
Revenues	1,409,360	1,390,834	18,526	1.3
Costs				
Purchased power	1,127,483	1,108,479	19,004	1.7
Operating expenses	117,828	131,786	(13,958)	(10.6)
Depreciation and amortization	70,560	68,886	1,674	2.4
	1,315,871	1,309,151	6,720	0.5
Income before the following:	93,489	81,683	11,806	14.5
Net financing charges	(36,820)	(36,962)	142	0.4
Gain on disposals of PP&E	-	4,717	(4,717)	(100.0)
Restructuring costs	(27,796)	-	(27,796)	100.0
Income before income taxes	28,873	49,438	(20,565)	(41.6)
Income tax expense (recovery)	161	(284)	445	(156.7)
Net income and comprehensive income	28,712	49,722	(21,010)	(42.3)
Basic and fully diluted net income per share	28,712	49,722	(21,010)	(42.3)

Interim Consolidated Balance Sheets Data
(in thousands of Canadian dollars, unaudited)

	As at June 30 2012 $	As at December 31 2011 $
Total assets	3,525,716	3,527,507
Current liabilities	955,684	483,399
Long-term liabilities	1,474,038	1,941,860
Total liabilities	2,429,722	2,425,259
Shareholder’s equity	1,095,994	1,102,248
Total liabilities and shareholder’s equity	3,525,716	3,527,507

Results of Operations

Net Income

Net income for the three months and six months ended June 30, 2012 was $41.5 million and $28.7 million compared to net income of $24.3 million and $49.7 million for the comparable periods in 2011.

The increase in net income for the three months ended June 30, 2012 was primarily due to lower operating expenses ($16.0 million) and higher net revenues ($5.7 million). These favourable variances were partially offset by higher income tax expense ($2.8 million) and a gain on disposals of PP&E recorded in the second quarter of 2011 ($1.8 million).

The decrease in net income for the six months ended June 30, 2012 was primarily due to restructuring costs incurred in conjunction with cost reduction initiatives at LDC recognized in the first quarter of 2012 (see "Results of Operations – Restructuring Costs" below) ($27.8 million), a gain on disposals of PP&E recorded in the second quarter of 2011 ($4.7 million), higher depreciation expense ($1.7 million), higher income tax expense ($0.5 million) and lower net revenues ($0.5 million). These unfavourable variances were partially offset by lower operating expenses ($14.0 million).

Net Revenues

Net revenues for the three months and six months ended June 30, 2012 were $144.6 million and $281.9 million compared to $139.0 million and $282.4 million for the comparable periods in 2011 (see "Non-GAAP Financial Measures" below).

The increase in net revenues for the three months ended June 30, 2012 was primarily due to higher regulated distribution revenue at LDC ($5.5 million). The increase in distribution revenue was primarily due to higher consumption in 2012 ($4.3 million).

The decrease in net revenues for the six months ended June 30, 2012 was primarily due to lower regulated distribution revenue at LDC ($0.6 million). The decrease in distribution revenue was primarily due to an adjustment recorded in 2012 for future taxes payable to customers ($4.6 million), partially offset by the approval by the OEB of higher average electricity distribution rates for 2012 compared to 2011 ($2.3 million) (see "Corporate Developments – Distribution Rates for LDC" below).

Expenses

Operating expenses for the three months and six months ended June 30, 2012 were $49.6 million and $117.8 million compared to $65.6 million and $131.8 million for the comparable periods in 2011.

The decrease in operating expenses for the three months ended June 30, 2012 was primarily due to a favourable reassessment for payments in lieu of property taxes to the Ministry of Finance of Ontario ("Ministry of Finance") recorded in the second quarter of 2012 following a change in regulation related to prior periods ($8.7 million) (see "Corporate Developments – Payments in Lieu of Additional Municipal and School Taxes" below), higher accounting conversion costs in 2011 following the decision by the OEB to disallow the recovery of a portion of the costs incurred by the Corporation ($3.0 million), lower bad debt expenses ($1.6 million) and lower compensation costs resulting from a workforce restructuring program initiated in the first quarter of 2012 ($2.7 million) (see "Restructuring Costs" below). These variances were partially offset by higher operating maintenance program costs at LDC in the second quarter of 2012 ($1.2 million).

The decrease in operating expenses for the six months ended June 30, 2012 was primarily due to a favourable reassessment for payments in lieu of property taxes to the Ministry of Finance recorded in the second quarter of 2012 following a change in regulation related to prior periods ($8.7 million) (see "Corporate Developments – Payments in Lieu of Additional Municipal and School Taxes" below), higher accounting conversion costs following the decision by the OEB to disallow the recovery of a portion of the costs incurred by the Corporation in 2011 ($3.0 million), lower bad debt expenses ($1.7 million) and a decrease in the provision relating to legal proceedings ($1.6 million). These variances were partially offset by an increase in operating maintenance program costs related to lower capital programs in 2012 ($2.7 million).

Depreciation and amortization expense for the three months and six months ended June 30, 2012 was $35.1 million and $70.6 million compared to $35.4 million and $68.9 million for the comparable periods in 2011.

The increase in depreciation and amortization expense for the six months ended June 30, 2012 was primarily due to the depreciation of assets capitalized during the last two quarters of 2011 and the first two quarters of 2012 in relation to the renewal of the regulated electricity distribution infrastructure of LDC ($12.1 million). This increase was partially offset by certain assets being fully depreciated ($5.7 million) and changes in accounting estimates related to the useful lives of certain assets ($4.5 million).

Gain on Disposals of PP&E

Gain on disposals of PP&E for the three months and six months ended June 30, 2012 was $nil compared to $1.8 million and $4.7 million for the comparable periods in 2011. The variance in gain on disposals of PP&E was primarily due to the recognition of gains realized in connection with the disposals of surplus properties at LDC in 2011.

Restructuring Costs

In the first quarter of 2012, the Corporation's Board of Directors approved a workforce restructuring program aimed at reducing operating expenditures for LDC. The program was approved following the decision by the OEB to deny the request of LDC to set its electricity distribution rates for 2012, 2013 and 2014 under the Cost of Service ("COS") framework. In preparing its application for electricity distribution rates for 2012, 2013 and 2014 using the IRM framework, including the filing of an Incremental Capital Module ("ICM") application, LDC concluded that significant cost reductions were necessary to manage its business within the confines of the expected allowed electricity distribution rates provided by the IRM framework. The main component of these operating cost reduction initiatives was a workforce restructuring program, which included the severance of management employees and a voluntary exit incentive program for targeted unionized positions. See "Corporate Developments – Distribution Rates for LDC" below.

Restructuring costs for the six months ended June 30, 2012 was $27.8 million compared to $nil for the comparable period in 2011. This balance is comprised of ongoing termination charges of $23.7 million and one-time termination incentive charges of $4.1 million, of which $19.3 million remains unpaid as at June 30, 2012.

Income Tax Expense (Recovery)

Income tax expense for the three months and six months ended June 30, 2012 was $0.2 million compared to an income tax recovery of $2.6 million and $0.3 million for the comparable periods in 2011.

The increase in the income tax expense for the three months ended June 30, 2012 was primarily due to higher earnings before taxes ($5.3 million), partially offset by higher deductions for permanent and temporary differences between accounting and tax treatments ($2.5 million).

The increase in the income tax expense for the six months ended June 30, 2012 was primarily due to lower deductions for permanent and temporary differences between accounting and tax treatments ($5.9 million), partially offset by lower earnings before taxes ($5.4 million).

Quarterly Results of Operations

The table below presents unaudited quarterly consolidated financial information of the Corporation for the eight quarters including and immediately preceding June 30, 2012.

Quarterly Results of Operations (in thousands of Canadian dollars, unaudited)	June 30 2012 $	March 31 2012 $	December 31 2011 $	September 30 2011 $
Revenues	709,700	699,660	694,284	738,352
Costs	649,831	666,040	653,374	687,280
Net income (loss)	41,538	(12,826)	17,228	28,982
	June 30 2011 $	**March 31 2011 $**	**December 31 2010 $**	**September 30 2010 $**
Revenues	686,646	704,188	659,043	683,376
Costs	648,685	660,466	623,573	634,679
Net income	24,270	25,452	10,048	27,687

The Corporation's quarterly results are impacted by changes in revenues resulting from variations in seasonal weather conditions, the fluctuations in electricity prices, and the timing and recognition of regulatory decisions. The Corporation's revenues tend to be higher in the first and third quarters of a year as a result of higher energy consumption for winter heating in the first quarter and air conditioning and cooling in the third quarter.

Financial Position

The following table outlines the significant changes in the consolidated balance sheets between June 30, 2012 and December 31, 2011.

Interim Consolidated Balance Sheets Data
As at June 30, 2012 compared to December 31, 2011
(in thousands of Canadian dollars, unaudited)

Balance Sheet Account	Increase (Decrease) $	Explanation of Significant Change
Assets		
Cash and cash equivalents	(33,425)	See "Liquidity and Capital Resources" below.
Investments	(34,002)	The decrease in investments is due to the sale and maturity of two floating rate notes in the amounts of $25.0 million and $9.0 million, the first was sold on February 15, 2012 and the second matured on February 17, 2012.
Accounts receivable, net of allowance for doubtful accounts	9,111	The increase in accounts receivable is primarily due to the timing of billing and collection activities.
Unbilled revenue	10,791	The increase in unbilled revenue is primarily due to higher energy prices compared to the previous period and higher consumption in June 2012 compared to December 2011.

Interim Consolidated Balance Sheets Data As at June 30, 2012 compared to December 31, 2011 (in thousands of Canadian dollars, unaudited)		
Balance Sheet Account	**Increase (Decrease) $**	**Explanation of Significant Change**
Income tax receivable	7,741	The increase in income tax receivable is primarily due to instalment payments during the period in excess of the income tax provision.
PP&E and intangible assets, net	44,308	The increase in PP&E and intangible assets is primarily due to capital expenditures ($115.3 million), partially offset by depreciation during the period ($70.6 million).
Liabilities and Shareholder's Equity		
Accounts payable and accrued liabilities	(15,522)	The decrease in accounts payable and accrued liabilities is mainly due to timing differences in the settlement of trade payables, partially offset by higher harmonized sales tax payable and higher electricity payable to the Independent Electricity System Operator ("IESO") due to higher consumption and energy prices.
Restructuring accrual	19,264	The restructuring accrual is primarily due to the workforce restructuring program initiated by the Corporation in the first quarter of 2012 (see "Results of Operations – Restructuring Costs" above).
Deferred revenue	5,900	The increase in deferred revenue is primarily due to advances from the Ontario Power Authority ("OPA") relating to CDM programs.
Regulatory liabilities	(10,139)	The decrease in regulatory liabilities is primarily due to the net disposition of retail settlement balances to customers approved by the OEB and a reduction of deferred income tax assets payable to customers.
Retained earnings	(6,254)	The decrease in retained earnings is due to dividends paid ($35.0 million), partially offset by net income during the period ($28.7 million).

Liquidity and Capital Resources

Sources of Liquidity and Capital Resources

The Corporation's primary sources of liquidity and capital resources are cash provided by operating activities, bank financing, interest income and borrowings from debt capital markets. The Corporation's liquidity and capital resource requirements are mainly for capital expenditures to maintain and improve the electricity distribution system of LDC, to purchase power, to meet financing charges and for prudential requirements.

The Corporation does not believe that equity contributions from the City, its sole shareholder, will constitute a source of capital.

Interim Consolidated Statement of Cash Flows (in thousands of Canadian dollars, unaudited)				
	Three months Ended June 30		Six months Ended June 30	
	2012 $	2011 $	2012 $	2011 $
Cash and cash equivalents, beginning of period ...	133,132	196,095	154,256	330,151
Net cash provided by operating activities	28,451	38,090	84,385	83,419
Net cash used in investing activities	(35,709)	(103,554)	(84,447)	(262,070)
Net cash used in financing activities	(5,043)	(10,893)	(33,363)	(31,762)
Cash and cash equivalents, end of period	120,831	119,738	120,831	119,738

Net Cash Provided by Operating Activities

Net cash provided by operating activities for the three months and six months ended June 30, 2012 was $28.5 million and $84.4 million compared to $38.1 million and $83.4 million for the comparable periods in 2011.

The decrease in net cash provided by operating activities for the three months ended June 30, 2012 was primarily due to a variance in the aggregate amount of accounts receivable and unbilled revenue due to the timing of billing and collection activities ($15.4 million), a decrease in deferred revenue primarily relating to cash received in advance from the OPA for CDM programs in 2011 ($9.0 million), a decrease in post-employment benefits ($8.9 million) and the recognition of a restructuring accrual in 2012 (see "Results of Operations – Restructuring Costs" above) ($5.4 million). These variances were partially offset by an increase in net income ($17.3 million), an increase in accounts payable and accrued liabilities primarily due to timing of payments to suppliers ($6.6 million), a decrease in income tax receivables ($3.2 million) and a decrease in gain on disposals of PP&E ($1.8 million).

The increase in net cash provided by operating activities for the six months ended June 30, 2012 was primarily due to a variance in the aggregate amount of accounts receivable and unbilled revenue due to the timing of billing and collection activities ($28.4 million), the recognition of a restructuring accrual in 2012 (see "Results of Operations – Restructuring Costs" above) ($19.3 million), the decrease in gain on disposals of PP&E ($4.7 million) and an increase in depreciation expense ($1.7 million). These variances were partially offset by a decrease in net income ($21.0 million), a decrease in post-employment benefits ($17.7 million) and a decrease in accounts payable and accrued liabilities primarily due to timing of payments to suppliers ($15.5 million).

Net Cash Used in Investing Activities

Net cash used in investing activities for the three months and six months ended June 30, 2012 was $35.7 million and $84.4 million compared to $103.6 million and $262.1 million for the comparable periods in 2011.

The decrease in net cash used in investing activities for the three months ended June 30, 2012 was primarily due to lower capital expenditures in 2012 ($55.0 million) and a higher change in net regulatory assets and liabilities ($30.7 million) primarily related to a higher variance in 2012 of retail settlement balances regulated by the OEB. These variances were partially offset by the net effect related to short-term investment activities of excess cash ($16.0 million).

The decrease in net cash used in investing activities for the six months ended June 30, 2012 was primarily due to lower capital expenditures in 2012 ($89.9 million), a variance related to short-term investment activities of excess cash ($68.0 million) and a higher change in net regulatory assets and liabilities ($23.1 million) primarily related to a higher variance in 2012 of retail settlement balances regulated by the OEB.

The following table summarizes the Corporation's capital expenditures for the periods indicated.

Capital Expenditures (in thousands of Canadian dollars, unaudited)				
	Three months Ended June 30		**Six months Ended June 30**	
	2012 $	**2011 $**	**2012 $**	**2011 $**
LDC				
Distribution system	41,817	90,789	101,408	177,668
Technology assets	5,731	8,791	9,873	14,662
Other [(1)]	2,284	3,921	3,611	9,703
	49,832	103,501	114,892	202,033
Other [(2)]	60	1,346	378	3,162
Total Capital Expenditures	49,892	104,847	115,270	205,195

Notes:

(1) Consists of leasehold improvements, vehicles, other work-related equipment, furniture and office equipment.

(2) Includes unregulated capital expenditures primarily related to TH Energy.

Under the current electricity distribution rates of LDC, the OEB-approved regulated capital expenditures amounted to approximately $140.0 million for 2012. For 2011, the OEB approved $378.8 million in regulated capital expenditures for LDC. On May 10, 2012, LDC filed an electricity distribution application for 2012, 2013 and 2014 using the IRM framework and including an ICM application. The application is seeking funding for total regulated capital expenditures of $448.7 million in 2012, $534.5 million in 2013 and $439.5 million in 2014 (see "Corporate Developments – Distribution Rates for LDC" below).

The decrease in regulated capital expenditures at LDC for the six months ended June 30, 2012 amounted to $87.1 million and was primarily due to the uncertainty surrounding LDC's capital work program as a result of the OEB's decision to impose the IRM framework for 2012. This decrease was primarily related to distribution lines ($51.3 million), metering ($6.3 million), switchgears ($5.6 million), feeders ($5.1 million), standardization assets ($4.1 million), and technology assets ($3.9 million).

The most significant areas for regulated capital expenditures incurred by LDC in the first six months of 2012 were related to maintaining the reliability of the electricity distribution system, primarily by replacing aging assets ($28.4 million), expenditures related to customer connections ($22.2 million), expenditures related to the standardization and improvement of the electricity distribution system ($17.9 million), and upgrades to stations ($16.9 million).

Net Cash Used in Financing Activities

Net cash used in financing activities for the three months and six months ended June 30, 2012 was $5.0 million and $33.4 million compared to $10.9 million and $31.8 million for the comparable periods in 2011.

The decrease in net cash used in financing activities for the three months ended June 30, 2012 compared to the same period in 2011 was primarily due to an increase in customer deposits in 2012 in compliance with OEB rules and regulations ($5.9 million).

The increase in net cash used in financing activities for the six months ended June 30, 2012 compared to the same period in 2011 was primarily due to a higher dividend paid with respect to net income for the year ended December 31, 2011, which was paid to the City on March 12, 2012 ($14.9 million), partially offset by an increase in customer deposits in 2012 in compliance with OEB rules and regulations ($13.3 million).

Summary of Contractual Obligations and Other Commitments

The following table presents a summary of the Corporation's debentures, major contractual obligations and other commitments.

Summary of Contractual Obligations and Other Commitments
As at June 30, 2012
(in thousands of Canadian dollars, unaudited)

	Total $	2012[1] $	2013/2014 $	2015/2016 $	After 2016 $
Debentures – principal repayment...	1,470,057	-	470,057	-	1,000,000
Debentures – interest payments.......	593,042	37,261	105,960	91,600	358,221
Operating lease obligations and future commitments.........................	50,545	3,276	30,642	13,149	3,478
Capital lease obligations ….............	14,290	1,204	4,799	4,740	3,547
Asset retirement obligations............	5,767	1,331	438	243	3,755
Total contractual obligations and other commitments….....................	2,133,701	43,072	611,896	109,732	1,369,001

Note:

(1) The amounts disclosed represent the balances due over the period July 1, 2012 to December 31, 2012.

Revolving Credit Facility

The Corporation is a party to a revolving credit facility expiring on May 3, 2013, pursuant to which the Corporation may borrow up to $400.0 million, of which up to $140.0 million is available in the form of letters of credit. Additionally, the Corporation is a party to a bilateral facility for $50.0 million for the purpose of issuing letters of credit mainly to support LDC's prudential requirements with the IESO.

As at June 30, 2012, no amounts had been drawn under the Corporation's revolving credit facility and $45.6 million had been drawn on the bilateral facility.

Prudential Requirements and Third Party Credit Support

The City has authorized the Corporation to provide financial assistance to its subsidiaries, and LDC to provide financial assistance to other subsidiaries of the Corporation, in the form of letters of credit and guarantees, for the purpose of enabling them to carry on their businesses up to an aggregate amount of $500.0 million.

Dividends

On March 2, 2012, the Board of Directors of the Corporation declared dividends in the amount of $29.0 million. The dividends were comprised of $23.0 million with respect to net income for the year ended December 31, 2011, which was paid to the City on March 12, 2012, and $6.0 million with respect to the first quarter of 2012, which was paid to the City on March 30, 2012.

On May 17, 2012, the Board of Directors of the Corporation declared a dividend in the amount of $6.0 million with respect to the second quarter of 2012, which was paid to the City on June 29, 2012.

On August 17, 2012, the Board of Directors of the Corporation declared a dividend in the amount of $6.0 million with respect to the third quarter of 2012. The dividend is payable on September 28, 2012.

Credit Ratings

The Corporation and the debentures issued under its medium-term note program were rated as follows:

Credit Ratings As at June 30, 2012		
	Rating	**Outlook**
DBRS Limited	A (high)	Stable
Standard & Poor's	A	Stable

Corporate Developments

Appointment

On July 13, 2012, the City, as sole shareholder of the Corporation, appointed Vincent Brescia on the Board of Directors of the Corporation. This appointment was effective immediately for a term ending November 12, 2012, or until a successor is appointed.

Distribution Rates for LDC

Regulatory developments in Ontario's electricity industry, including current and possible future consultations between the OEB and interested stakeholders, may affect LDC's electricity distribution rates and other permitted recoveries in the future.

LDC's electricity distribution rates for 2011 were determined through an application under the COS framework. The COS framework sets electricity distribution rates using a detailed examination of evidence and an assessment of the costs incurred by an electricity distributor to provide services to its customers.

On July 7, 2011, the OEB issued its decision regarding LDC's electricity distribution rates for 2011. The decision provided for a distribution revenue requirement and rate base of $522.0 million and $2,298.2 million, respectively. In addition, the decision provided for capital program spending levels and operating, maintenance and administration spending levels of $378.8 million and $238.0 million, respectively.

On August 26, 2011, LDC filed a rate application, following the COS framework, with the OEB seeking approval of separate and successive revenue requirements and corresponding electricity distribution rates for 2012, 2013 and 2014. The requested distribution revenue requirements for these years were $571.4 million, $639.5 million, and $712.8 million, respectively, and the expected rate bases for these years were $2,636.3 million, $3,053.5 million, and $3,503.2 million, respectively.

Pursuant to the IRM framework, the OEB established, as a preliminary issue in the above application, that it would consider the question of whether the application filed by LDC under the COS framework was acceptable or whether it should be dismissed. The IRM framework provides for an adjustment to an electricity distributor's rates based on a formulaic calculation with the possibility to request an ICM to address specific capital expenditure needs not covered by the formulaic calculation. The review of an ICM application is done by the OEB following defined criteria, such as materiality, causation and prudence.

LDC filed evidence supporting its position for electricity distribution rates to be set under the COS framework for 2012, 2013 and 2014. The OEB established a process by which a portion of LDC's evidence was tested during an oral hearing held in November 2011.

On January 5, 2012, the OEB rendered its decision on the preliminary issue and dismissed LDC's COS framework application for 2012, 2013 and 2014. In its decision, the OEB found that LDC was not permitted to deviate from the standard IRM framework cycle. Accordingly, LDC was required to file its request for electricity distribution rates for 2012, 2013 and 2014 pursuant to the IRM framework and to use the ICM to request the capital needed for infrastructure renewal.

On January 25, 2012, LDC filed a motion with the OEB to review the OEB's January 5, 2012 decision.

On February 6, 2012, LDC filed a notice of appeal with the Ontario Divisional Court regarding the OEB's January 5, 2012 decision.

On May 10, 2012, LDC filed an application for electricity distribution rates for 2012, 2013 and 2014 using the IRM framework, including the filing of an ICM application. The formulaic adjustment, requested by LDC, follows the guidelines provided by the OEB and seeks to increase the current revenue requirement by 0.68% to $525.5 million for 2012, $529.1 million for 2013 and $532.7 million for 2014. The 2013 and 2014 formulaic adjustment may be subject to change depending on future inflation and market data.

The ICM proposed by LDC establishes rate riders allowing for the recovery of capital spending of $275.7 million for 2012, $361.5 million for 2013 and $266.5 million for 2014 in excess of the OEB's threshold amounts. The calculation of the related requested rate riders was derived using guidelines provided by the OEB. Accordingly, when factoring in the amount of capital currently included in LDC's electricity distribution rates, the total amount of capital requested amounts to $448.7 million for 2012, $534.5 million for 2013 and $439.5 million for 2014.

The current application is expected to be subject to an in-depth review by the OEB over the next few months. There can be no assurance that the OEB will allow for the total or partial recovery of the capital expenditure balances requested in the current application. The outcome of the current application could have a material impact on the Corporation's consolidated financial statements in the future.

CDM Activities

On March 31, 2010, the Minister of Energy and Infrastructure of Ontario, under the guidance of sections 27.1 and 27.2 of the *Ontario Energy Board Act, 1998* (Ontario), directed the OEB to establish CDM targets to be met by electricity distributors. Accordingly, on November 12, 2010, the OEB amended LDC's distribution licence to require LDC, as a condition of its licence, to achieve 1,304 GWh of energy savings and 286 Megawatts of summer peak demand savings, over the period beginning January 1, 2011 through December 31, 2014.

Effective January 1, 2011, LDC entered into an agreement with the OPA to deliver CDM programs in the amount of approximately $50.0 million extending from January 1, 2011 to December 31, 2014 (the "Master CDM Program Agreement"). As at June 30, 2012, LDC received approximately $27.6 million from the OPA for the delivery of CDM programs under the Master CDM Program Agreement. All programs to be delivered under the Master CDM Program Agreement are fully funded and paid in advance by the OPA. Upon expiration of the agreement, LDC is required to repay to the OPA any excess funding received for program administration less any cost efficiency incentives. These programs are expected to support the achievement of the mandatory CDM targets described above.

OEB PILs Proceeding

The OEB conducted a review of the Payments In Lieu of Corporate Taxes ("PILs") variances accumulated in regulatory variance accounts for the period from October 1, 2001 to April 30, 2006 for certain Municipal Electricity Utilities ("MEUs"). On June 24, 2011, the OEB issued its decision for these MEUs and provided guidelines for the calculation and further disposition of the balances accumulated in the PILs regulatory variance accounts. The OEB has issued interrogatories and decisions for other MEUs subsequent to its previous decision.

LDC has reviewed the balances of its PILs regulatory variance accounts and applied the guidelines provided by the OEB. As at June 30, 2012, LDC estimated its liability at approximately $6.6 million. This balance has been recorded in the Corporation's Interim Consolidated Financial Statements. LDC has applied for disposition of the balance as part of its pending IRM application filed on May 10, 2012. The amount to be approved by the OEB will be based on the OEB's interpretation and application of its guidelines and the final balance which is yet to be approved by the OEB could differ materially from LDC's estimation of its liability.

Payments in Lieu of Additional Municipal and School Taxes

The Ministry of Finance had issued assessments in respect of payments in lieu of additional municipal and school taxes under section 92 of the *Electricity Act, 1998* (Ontario) that were in excess of the amounts LDC believed were payable. The dispute arose as a result of inaccurate information incorporated into Ontario Regulation 224/00.

The Corporation worked with the Ministry of Finance to resolve this issue, and as a result the Ministry of Finance issued Ontario Regulation 423/11 on August 31, 2011. The new regulation revoked Ontario Regulation 224/00 and corrected inaccurate information retroactively to 1999.

In May 2012, the Ministry of Finance completed its reassessment as a consequence of the change in regulation. The impact of the reassessment issued was favourable to the Corporation.

Legal Proceedings

In the ordinary course of business, the Corporation is subject to various litigation and claims with customers, suppliers, former employees and other parties. On an ongoing basis, the Corporation assesses the likelihood of any adverse judgments or outcomes as well as potential ranges of probable costs and losses. A determination of the provision required, if any, for these contingencies is made after an analysis of each individual issue. The provision may change in the future due to new developments in each matter or changes in approach, such as a change in settlement strategy.

Christian Helm Class Action

On December 6, 2010, a statement of claim in a proposed class action was issued against LDC. The claim sought general and special damages in the amount of $100.0 million for disgorgement of unjust gains allegedly resulting from the receipt of interest on overdue accounts in contravention of the *Interest Act* (Canada). On April 30, 2012, a settlement reached by the parties was approved by Order of the Ontario Superior Court of Justice. Pursuant to the terms of the Order, LDC was required to pay the amount of $5.8 million plus costs in settlement of all claims, substantially all of which has been paid as at June 30, 2012. The Corporation accrued a liability to cover the expected settlement in 2010. The action has been dismissed, and the claims by all class members have been released.

2 Secord Avenue

An action was commenced against LDC in September 2008 in the Ontario Superior Court of Justice under the *Class Proceedings Act, 1992* (Ontario) ("Class Proceedings Act") seeking damages in the amount of $30.0 million as compensation for damages allegedly suffered as a result of a fire and explosion in an underground vault at 2 Secord Avenue on July 20, 2008. This action is at a preliminary stage. The statement of claim has been served on LDC, a statement of defence and third party claim have been served by LDC and a third party defence and counterclaim against LDC seeking damages in the amount of $51.0 million have been filed. A certification order has been issued. Affidavits of documents have been produced by LDC to the other parties and examinations for discovery have commenced and are continuing. Given the preliminary status of this action, it is not possible to reasonably quantify the effect, if any, of this action on the financial performance of the Corporation. If damages were awarded, LDC would make a claim under its liability insurance which the Corporation believes would cover any damages which may become payable by LDC in connection with the action.

On December 20, 2010, LDC was served with a statement of claim by the City seeking damages in the amount of $2.0 million as a result of the fire at 2 Secord Avenue. A statement of defence and a third party claim have been served. Given the preliminary status of this action, it is not possible to reasonably quantify the effect, if any, of this action on the financial performance of the Corporation. If damages were awarded, LDC would make a claim under its liability insurance which the Corporation believes would cover any damages which may become payable by LDC in connection with the action.

On January 24, 2012, by order of the court the above actions and a smaller non-class action commenced in April 2009 involving the same incident will be tried at the same time or consecutively.

2369 Lakeshore Boulevard West

A third party action was commenced against LDC in October 2009 in the Ontario Superior Court of Justice under the Class Proceedings Act seeking damages in the amount of $30.0 million as compensation for damages allegedly suffered as a result of a fire in the electrical room at 2369 Lakeshore Boulevard West on March 19, 2009. Subsequently, in March 2010, the plaintiff in the main action amended its statement of claim to add LDC as a defendant. The plaintiff in the main action seeks damages in the amount of $10.0 million from LDC. Both actions

are at a preliminary stage and the certification hearing is scheduled for September 2012. Statements of defence to the main action and to the third party claim have not been filed. Accordingly, given the preliminary status of these actions, it is not possible at this time to reasonably quantify the effect, if any, of these actions on the financial performance of the Corporation. If damages were awarded, LDC would make a claim under its liability insurance which the Corporation believes would cover any damages which may become payable by LDC in connection with these actions.

Another third party action was commenced against LDC in October 2009 in the Ontario Superior Court of Justice seeking damages in the amount of $30.0 million as compensation for damages allegedly suffered as a result of the fire at 2369 Lakeshore Boulevard West. Subsequently, in March 2010, the plaintiff in the main action amended its statement of claim to add LDC as a defendant. The plaintiff in the main action seeks damages in the amount of $0.4 million from LDC. LDC has filed a statement of defence, crossclaim and counterclaim. Examinations for discovery have not taken place, notwithstanding a court ordered timetable to have them completed by February 29, 2012. Accordingly, given the preliminary status of these actions, it is not possible at this time to reasonably quantify the effect, if any, of these actions on the financial performance of the Corporation. If damages were awarded, LDC would make a claim under its liability insurance which the Corporation believes would cover any damages which may become payable by LDC in connection with these actions.

On August 29, 2011, LDC was served with a statement of claim by the owner of the building and the property management company for the building seeking damages in the amount of $2.0 million as a result of the fire at 2369 Lakeshore Boulevard West. LDC has filed a statement of defence and counterclaim. Given the preliminary status of this action, it is not possible to reasonably quantify the effect, if any, of this action on the financial performance of the Corporation. If damages were awarded, LDC would make a claim under its liability insurance which the Corporation believes would cover any damages which may become payable by LDC in connection with the action.

Share Capital

The authorized share capital of the Corporation consists of an unlimited number of common shares of which 1,000 common shares are issued and outstanding as at the date hereof.

Transactions with Related Parties

The City is the sole shareholder of the Corporation. Subsidiaries of the Corporation provide certain services to the City at commercial and regulated rates, including electricity, street lighting and other energy related services. All transactions with the City are conducted at prevailing market prices and normal trade terms. Additional information with respect to related party transactions between the Corporation and its subsidiaries, as applicable, and the City is set out below.

Transactions with Related Parties Summary
(in thousands of Canadian dollars, unaudited)

	Three months Ended June 30		Six months Ended June 30	
	2012 $	2011 $	2012 $	2011 $
Revenues	37,812	36,825	78,227	75,152
Operating expenses and capital expenditures	6,993	5,024	12,042	9,336
Dividends	6,000	6,000	34,966	20,063

Transactions with Related Parties Summary
(in thousands of Canadian dollars, unaudited)

	As at June 30 2012 $	As at December 31 2011 $
Accounts receivable	8,273	8,412
Unbilled revenue	9,006	8,692
Other assets	7,430	7,279
Accounts payable and accrued liabilities	26,101	25,085
Advance deposits	8,754	8,714

Revenues represent amounts charged to the City primarily for electricity and street lighting services. Operating expenses and capital expenditures represent amounts charged by the City for purchased road cut repairs, property taxes and other services. Dividends represent dividends paid to the City.

Accounts receivable represent receivables from the City primarily for street lighting, electricity and other services. Unbilled revenue represents receivables from the City related to the provision of electricity and other services provided and not yet billed. Other assets represent amounts for prepaid land leases from the City. Accounts payable and accrued liabilities represent amounts payable to the City relating to road cut repairs, property taxes and other services, as well as funds received from the City for the construction of electricity distribution assets. Advance deposits represent funds received from the City for future expansion projects.

See note 20 to the Interim Consolidated Financial Statements.

Non-GAAP Financial Measures

The Corporation's MD&A includes "net revenue" which is a non-GAAP financial measure. The definition of net revenues is revenue minus the cost of purchased power. This measure does not have any standard meaning prescribed by US GAAP and is not necessarily comparable to similarly titled measures of other companies. The Corporation uses this measure to assess its performance and to further make operating decisions.

Significant Accounting Policies

The Interim Consolidated Financial Statements of the Corporation have been prepared in accordance with US GAAP, including accounting principles prescribed by the OEB in the AP Handbook, and are presented in Canadian dollars. In preparing the Interim Consolidated Financial Statements, management makes estimates and assumptions which affect the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities at the date of the Interim Consolidated Financial Statements and the reported amounts of revenues and expenses for the period. Actual results could differ from those estimates, including changes as a result of future decisions made by the OEB, the Ministry of Energy, or the Ministry of Finance. The significant accounting policies of the Corporation are summarized in note 4 to the Interim Consolidated Financial Statements.

Future Accounting Pronouncements

A number of new standards and interpretations are not yet effective for the period ended June 30, 2012. The Corporation continues to analyze these standards and has initially determined that the following could have a significant effect on the consolidated financial statements.

In December 2011, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") No. 2011-11, "Balance Sheet (Topic 210): *Disclosures about Offsetting Assets and Liabilities*" ("ASU 2011-11"). The amendments require an entity to disclose both gross and net information about financial instruments and transactions eligible for offset in the consolidated balance sheets. ASU 2011-11 is effective for fiscal years, and interim periods within those years, beginning on or after January 1, 2013. Retrospective application is required. The adoption of this amendment is expected to increase disclosures related to offsetting assets and liabilities and is not expected to have an impact to the Corporation's consolidated balance sheets.

US GAAP Transition

Publicly accountable enterprises in Canada were required to adopt IFRS for interim and annual reporting purposes for fiscal years beginning on or after January 1, 2011. On September 10, 2010, the Accounting Standards Board ("AcSB") granted an optional one-year deferral for IFRS adoption for entities subject to rate regulation due to the uncertainty created by the International Accounting Standards Board ("IASB") in regard to rate-regulated accounting. The Corporation elected to take the optional one-year deferral of its adoption of IFRS, and accordingly, continued to prepare its Consolidated Financial Statements in accordance with Canadian GAAP for 2011. In the absence of a definitive plan to consider the issuance of a rate-regulated accounting standard by the IASB, the Corporation decided to evaluate the option of adopting US GAAP effective January 1, 2012 as an alternative to IFRS. On August 26, 2011, the Board of Directors of the Corporation approved the adoption of US GAAP for financial reporting purposes for the year beginning on January 1, 2012.

The accounting policies set out in note 4 to the Interim Consolidated Financial Statements have been applied consistently in preparing the Interim Consolidated Financial Statements and the comparative periods. The Corporation's first US GAAP annual consolidated financial statements will be dated December 31, 2012.

The quantification and reconciliation of the Corporation's consolidated balance sheet as at December 31, 2011, prepared in accordance with US GAAP as compared to Canadian GAAP is an increase to both total assets and total liabilities of approximately $71.7 million. The increase is primarily due to the recognition of unamortized actuarial losses and prior service costs and the reclassification of debt issuance costs in accordance with US GAAP. With respect to the consolidated statement of income and comprehensive income for the period ended December 31, 2011, net income was not impacted due to the Corporation's continued ability to apply rate-regulated accounting policies. Based on the detailed assessment of the key accounting areas for which significant Canadian GAAP and US GAAP differences were identified, there was no impact to equity and net earnings from that previously reported in the Interim and Annual Consolidated Financial Statements.

The Corporation has adjusted amounts reported previously in its Interim and Annual Consolidated Financial Statements prepared in accordance with Canadian GAAP. For reporting purposes, the transition date to US GAAP is January 1, 2011, which is the commencement of the 2011 interim comparative period to the Corporation's 2012 Interim Consolidated Financial Statements. A reconciliation of the transition from Canadian GAAP to US GAAP from January 1, 2011 and December 31, 2011 is provided in note 24 to the Interim Consolidated Financial Statements.

As a result of the transition to US GAAP, there was no significant impact on the Corporation's internal controls, information technology systems and financial reporting expertise requirements. The Corporation has completed topic-specific and relevant training to affected finance and operational teams on all key differences between Canadian GAAP and US GAAP, including management, the Board of Directors, and relevant committees thereof, including the audit committee. During the remainder of 2012, the Corporation will continue to focus on training for any key developments in US GAAP and the potential impacts to the Corporation's consolidated financial statements. Due to the limited differences between Canadian GAAP and US GAAP, the Corporation's debt covenants were not impacted by the conversion to US GAAP.

On February 28, 2012, LDC submitted a letter to the OEB requesting an accounting order establishing a deferral account to record the accounting differences between Canadian GAAP and US GAAP. The OEB's approval to establish this deferral account would allow the Corporation to record the financial impacts associated with the accounting framework transition for regulatory reporting purposes. The OEB's decision on this accounting order application will not constitute a decision with respect to the Corporation's use of US GAAP for regulatory reporting purposes. LDC will seek the OEB's approval to use US GAAP for regulatory reporting purposes in its next COS application. On June 7, 2012, the OEB approved the establishment of the accounting policy changes account to record the expected electricity distribution charges to customers arising from timing differences in the recognition of actuarial gains and losses and prior service costs related to other post-retirement benefits.

Selected Financial Highlights

The following table sets forth selected financial information of the Corporation for the three months and six months ended June 30, 2012 and for the comparable periods in 2011. This information has been derived from the Interim Consolidated Financial Statements.

Selected Financial Highlights
(in thousands of Canadian dollars, unaudited)

	Three months Ended June 30		Six months Ended June 30	
	2012 $	**2011 $**	**2012 $**	**2011 $**
Net revenues [1]	144,647	138,986	281,877	282,355
Operating expenses [1]	49,646	65,611	117,828	131,786
Net income [1]	41,538	24,270	28,712	49,722
Capital expenditures [2]	49,892	104,847	115,270	205,195

Notes:

(1) See "Results of Operations" for further details on net revenues, operating expenses and net income.
(2) See "Liquidity and Capital Resources" for further details on capital expenditures.

Additional Information

Additional information with respect to the Corporation (including its annual information form) is available at www.sedar.com.

Toronto, Canada

August 17, 2012

Insight beyond the rating.

Rating Report

Report Date:
January 20, 2012

Previous Report:
February 10, 2011

Toronto Hydro Corporation

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The Company

Toronto Hydro Corporation is a holding company with the following subsidiaries: Toronto Hydro-Electric System Ltd., which distributes electricity, and Toronto Hydro Energy Services Inc., which provides street lighting and expressway lighting services, as well as energy-efficient products and services. Toronto Hydro's sole shareholder is the City of Toronto (the City), rated AA by DBRS.

Rating

Debt	Rating	Rating Action	Trend
Short-Term Issuer Rating	R-1 (low)	Confirmed	Stable
Senior Unsecured Debentures & Medium Term Notes	A (high)	Confirmed	Stable

Rating Update

DBRS has confirmed the Senior Unsecured Debentures & Medium Term Notes and Short-Term Issuer ratings of Toronto Hydro Corporation (THC or the Company) at A (high) and R-1 (low), respectively. The trends are both Stable. The rating confirmations reflect relatively stable earnings contributions from THC's regulated distribution business and a strong credit profile.

DBRS notes that on January 5, 2011, the Ontario Energy Board (OEB) announced that it had turned down THC's electricity distribution rate increase application under the cost-of-service framework for the May 2012 to May 2014 period. DBRS expects the Company to proceed with a follow-up filing under the Incentive Regulation Mechanism (IRM) framework, as recommended by the OEB.

Under the IRM framework, the Company's actual rate of return on equity in the next rate period will likely weaken from the current allowed level of 9.58%, due to challenges associated with operating efficiency improvements and potential restructuring charges. In addition, the Company will be required to manage its capital program effectively within its regulatory limits. This could be a challenge in the medium term due to THC's aging regulated electricity distribution infrastructure, which could require a costly and extensive refurbishment to improve reliability. However, in the near term, key financial ratios – including interest coverage, leverage and cash flow ratios – are expected to be stronger under IRM than under the cost-of-service framework as THC should reduce capital spending to around its approved depreciation level.

Rating Considerations

Strengths

(1) Reasonable regulatory environment
(2) Strong franchise area
(3) Strong financial profile

Challenges

(1) Aging infrastructure
(2) Earnings sensitive to volume of electricity sold
(3) Low electricity consumption growth

Financial Information

	9 mos.ending Sept. 30		12 mos.	For the year ended December 31				
($ thousands- CAD, where applicable)	2011	2010	Sept. 30	2010	2009	2008	2007	2006
Net income before extras.	73,684	50,984	82,638	59,938	42,169	68,029	65,463	116,552
Cash flow (before working cap. changes)	183,959	185,413	251,566	253,020	221,804	232,720	199,837	257,484
Return on equity	9.2%	6.7%	7.8%	5.9%	4.3%	7.1%	7.2%	13.4%
Net debt in capital structure	53.5%	50.5%	53.5%	51.0%	50.0%	46.9%	51.6%	49.6%
Total debt in capital structure	56.4%	58.0%	56.4%	57.6%	54.8%	55.2%	56.5%	57.5%
Cash flow (times)/Total debt	17.4%	17.3%	17.8%	17.9%	18.3%	19.3%	16.6%	21.4%
EBIT interest coverage (times)	2.31	2.12	2.20	2.05	1.73	1.77	2.07	2.66

Toronto Hydro Corporation

Report Date:
January 20, 2012

Rating Considerations Details

Strengths

(1) **Low business risk profile in a regulated market:** THC is predominantly a regulated electric distribution company that operates in a reasonable regulatory environment. The Company's regulated business model provides a high degree of stability to earnings and cash flow over the longer term.

(2) **Strong franchise area:** THC is one of the largest municipally owned local distribution companies (LDCs) in Canada, serving a customer base of 700,000 users. Approximately 91% of THC's electricity throughput is to residential and general service customers. Demand from these customers is relatively stable year over year, as they are less sensitive to economic cycles when compared to large users (9% of demand).

(3) **Solid financial profile and credit metrics:** The Company continues to maintain strong and stable credit metrics and a healthy balance sheet. DBRS expects cash flow, leverage and coverage metrics to improve under IRM, largely due to expected lower capital spending.

Challenges

(1) **Aging infrastructure:** Some of THC's assets date back to the 1950s. It is expected over the next five to nine years that about 30% of the Company's assets will be nearing the end of their serviceable life, with some assets in operation beyond this point. Historically, the Company has been in line with industry standards as measured by their System Average Interruption Duration Index (SAIDI) and System Average Interruption Frequency Index (SAIFI); however, approximately 40% of the downtime represented in these indicators is from defective equipment. Given the likelihood of moving to IRM and the probability of a reduced capital expenditure budget, THC will have to be very strategic on how they allocate their capex programs going forward.

(2) **Earnings sensitivities due to volumes sold:** Earnings and cash flow for electricity distribution companies are partially dependent on the volume of electricity sold, given that rates typically include a variable charge component. Seasonality, economic cyclicality and weather variability have a direct impact on the volume of electricity sold and, therefore, on revenue earned from electricity sales.

(3) **Low electricity volume growth:** THC has been experiencing low distribution volume growth, partly due to energy conservation initiatives and the negative impacts of the recent economic recession. The average load growth was less than 1% over the past five years.

Toronto Hydro Corporation

Report Date:
January 20, 2012

Earnings and Outlook

	9 mos.ending Sept. 30		12 mos.	For the year ended December 31				
($ millions, CAD, where applicable)	2011	2010	Sept. 30	2010	2009	2008	2007	2006
Net operating revenues	424.1	410.2	563.3	549.4	504.3	495.8	497.6	541.1
Operating Expenses*	288.8	289.0	392.6	392.7	371.8	359.6	334.4	331.5
EBITDA	242.3	242.5	325.9	326.1	295.4	292.4	307.2	346.9
EBIT	135.28	121.20	170.75	156.67	132.46	136.20	163.23	209.60
Gross interest expense	58.61	57.22	77.74	76.36	76.51	76.77	78.76	78.80
Payments in lieu of income tax	5.78	17.54	13.81	25.58	19.74	5.75	37.80	58.40
Net income before extraordinary items	74	51	83	60	42	68	65	117
Reported net income	79	56	89	66	42	169	83	92
Return on equity*	9.2%	6.7%	7.8%	5.9%	4.3%	7.1%	7.2%	13.4%
Operating Margin	6.4%	6.2%	6.2%	6.0%	5.4%	5.7%	6.9%	9.3%
*DBRS adjusted numbers								

2010 versus 2009

- Revenue increased in 2010 versus 2009 due to the OEB approved distribution rate increases of $31.3 million and marginal increases in electricity consumption.
- Net income before extraordinary items was higher year over year as a result of a growing regulated rate base, partially offset by higher operating expenses.

9M 2011 versus 9M 2010

- Net income before extraordinary items increased by $23 million in 9M 2011 versus 9M 2010 mainly due to an increase in distribution revenues ($18.7 million) and a lower provision for payments in lieu of income taxes ($11.8 million).
- The OEB approved the distribution rate increases to help fund THC's regulated electricity distribution infrastructure upgrade initiatives as well as its workforce renewal program.

Electricity Throughputs (million GWh)	%	2010	2009	2008	2007	2006
Residential	21%	5,209	5,037	5,216	5,332	5,352
General service	70%	17,318	16,855	17,415	17,837	17,583
Large users	9%	2,219	2,462	2,508	2,591	2,592
Total (million GWh)	100%	24,746	24,354	25,139	25,760	25,527
Growth in electricity throughputs		1.6%	-3.1%	-2.4%	0.9%	-3.2%
Customers	%	2010	2009	2008	2007	2006
Residential	89%	620,501	611,357	605,509	601,515	599,080
General service	11%	79,836	78,840	78,589	78,349	78,978
Large users	0%	50	47	47	49	49
Total	100%	700,387	690,244	684,145	679,913	678,107
Growth in customer base		1.5%	0.9%	0.6%	0.3%	0.2%

Outlook

- Under the IRM framework, the Company's actual rate of return on equity in the next rate period will likely weaken from the current allowed level of 9.58% due to challenges associated with operating efficiency improvements and potential restructuring charges.

Toronto Hydro Corporation

Report Date:
January 20, 2012

Financial Profile and Outlook

	9 mos.ending Sept. 30		12 mos.	For the year ended December 31				
($ thousands)	2011	2010	Sept. 30	2010	2009	2008	2007	2006
Net income before extraordinary items	73,684	50,984	82,638	59,938	42,169	68,029	65,463	116,552
Depreciation, depletion & amortization	107,038	121,267	155,179	169,408	162,970	156,159	143,983	137,344
Deferred income taxes and other	3,237	13,162	13,749	23,674	16,665	8,532	(9,609)	3,588
Cash flow (before working cap. changes)	183,959	185,413	251,566	253,020	221,804	232,720	199,837	257,484
Dividends paid	(26,063)	(18,000)	(33,063)	(25,000)	(25,170)	(116,416)	(46,200)	(46,200)
Capital expenditures	(306,796)	(244,863)	(452,717)	(390,784)	(249,305)	(214,581)	(289,502)	(185,307)
Free Cash Flow (bef. work. cap. changes)	(148,900)	(77,450)	(234,214)	(162,764)	(52,671)	(98,277)	(135,865)	25,977
Changes in non-cash work. cap. items	25,578	30,865	22,011	27,298	(31,047)	33,746	14,317	(144,756)
Net Free Cash Flow	(123,322)	(46,585)	(212,203)	(135,466)	(83,718)	(64,531)	(121,548)	(118,779)
Acquisitions & Long-term Investments	(59,041)	0	(59,041)	0	0	0	(88,000)	0
Short-term Investments	0	0	0	0	7	0	0	0
Proceeds on asset sales	29,277	8,787	79,701	59,211	1,056	0	1,845	938
Net equity change	0	0	0	0	0	0	0	0
Net debt change	0	198,493	0	198,493	3,341	0	4,608	(1,182)
Other	(23,112)	(561)	(26,008)	(3,457)	(49,801)	189,021	91,573	(2,398)
Change in cash	(176,198)	160,134	(217,551)	118,781	(129,115)	124,490	(111,522)	(121,421)
Total debt	1,410,405	1,429,416	1,410,405	1,409,837	1,210,590	1,206,694	1,206,188	1,205,231
Cash and equivalents	153,953	371,504	153,953	330,151	211,370	340,492	216,002	327,524
Net debt in capital structure	53.5%	50.5%	53.5%	51.0%	50.0%	46.9%	51.6%	49.6%
Total debt in capital structure	56.4%	58.0%	56.4%	57.6%	54.8%	55.2%	56.5%	57.5%
Adjusted total debt in capital structure*	56.6%	58.1%	56.6%	58.5%	55.4%	55.8%	57.2%	58.0%
Net debt/cash flow (times)	5.12	4.28	4.99	4.27	4.50	3.72	4.95	3.41
Total debt/cash flow (times)	5.75	5.78	5.61	5.57	5.46	5.19	6.04	4.68
Adjusted total debt/cash flow (times)*	5.80	5.81	5.65	5.79	5.58	5.32	6.21	4.79
EBIT interest coverage (times)	2.31	2.12	2.20	2.05	1.73	1.77	2.07	2.66
Adjusted EBIT interest coverage (times)*	2.31	2.12	2.20	2.09	1.76	1.80	2.09	2.67
*Including operating leases.								

Summary

- THC's financial profile remained strong and key financial ratios were reasonable for the assigned rating category.
- Free cash flow deficits continued in 2010 and 9M 2011, primarily due to increased levels of capital spending to modernize THC's aging regulated electricity distribution infrastructure.
- The cash flow deficits in 2010 were financed primarily with debt and in part through the sale of all their asset-backed commercial paper (ABCP) notes (restructured after the liquidity crisis in 2007).
- Dividends remained steady over the past two years as per the shareholders' direction adopted by the City of Toronto, which states that the Company will pay $25 million (in segments throughout the year) per year and, if applicable, 50% of any consolidated net income surpassing this amount.

Outlook

- The Company will be required to manage its capital program effectively and within it regulatory limits. This could be a challenge in the medium term due to its aging regulated electricity distribution infrastructure, which could require a costly and extensive refurbishment of the distribution network to improve reliability.
- However, in the near term, key financial ratios – including interest coverage, leverage and cash flow ratios – are expected to be stronger under IRM than under the cost-of-service framework as THC should reduce its capital spending to around its approved depreciation level.

Long-Term Debt Maturities and Bank Lines

- THC's liquidity profile remains strong and sufficient to cover all near to medium-term obligations. Prior to the quarter ending September 30, 2011, THC consistently maintained cash balances of more than $210 million.

($ millions - As at Sep. 30, 2011)	Amount	Draw/LOCs	Available	Expiry
Cash & Cash Equivalents	154	-	154	-
Credit Facility*	400	0	400	3-May-13
Bilateral facility	50	45.1	4.9	Demand
		Total:	**559**	

- THC remains fairly flexible, with the ability to scale down or postpone dividends. Dividend payments to the City of Toronto require the board of director's approval and have consistently remained around $25 million as per the shareholders' direction.

Debt - As at Dec 31. 2011		
($ millions)	**Maturity**	**Outstanding**
Series 1 - 6.11%	7-May-13	224.2
Series 2 - 5.15%	14-Nov-17	248.9
Series 3 - 4.49%	12-Nov-19	248.6
Series 5 - 6.11%	6-May-13	245.1
Series 6 - 5.54%	21-May-40	198.7
Series 7 - 3.54%	18-Nov-21	300.0
	Total:	**1,465.4**

Long-term Debt Maturities						
($ millions - As at Dec. 31, 2011)	**2012**	**2013**	**2014**	**2015**	**2016+**	**Total**
Amount	0	469	0	0	996	1465
% of Total	0.0%	32.0%	0.0%	0.0%	68.0%	100.0%

- While 32% of the long-term debt is maturing in 2013, DBRS does not believe re-financing will pose a problem for the Company given its recent successes:
  - The Series 4 debenture with $254.1 million outstanding was re-financed in November 2011, with a 3.54% $300 million unsecured debenture (Series 7) maturing in November 2021 (rated A (high)).
  - The City of Toronto's promissory note of $490 million was converted into THC issued Series 4 and Series 5 debentures (maturing Dec 30, 2011, and May 6, 2013, respectively) and sold in the secondary market (no proceeds to THC).
- The Company has access to a shelf prospectus initiated December 9, 2010, for the issuance of $1 billion active for 25 months following this prospectus date.
- DBRS notes that THC does not currently have a commercial paper program.

Regulation

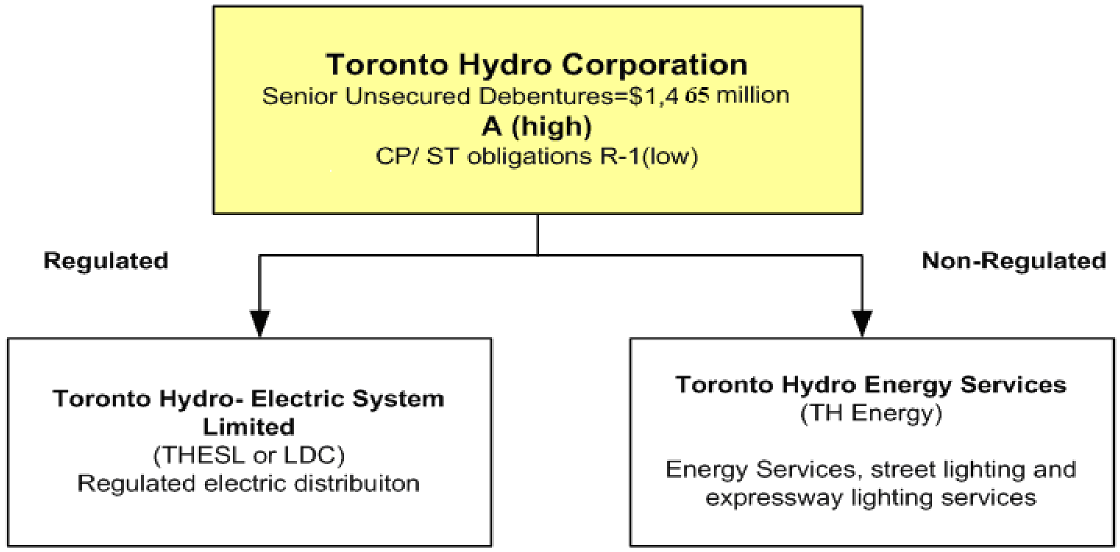
Provincial Regulation

- THC's regulated electricity distribution business operates within the bounds of the OEB, whose mandate is to approve and set rates for the distribution and transmission of electricity as set out by the *Electricity Act*, 1998.
- THC operates with a deemed capital structure of 60% debt (divided into 56% long term and 4% short term) and 40% equity.
- In December 2009, the OEB changed its methodology for calculating return on equity (ROE), resulting in a decrease in ROE to 9.58% for 2011, down from 9.85% in 2010.
- The new calculation is composed of a base ROE of 9.75% plus 50% of the change in the long Canada Bond forecast from base year, and 50% of the change in the spread of an "A"-rated bond index over the 30-year Canada bond yield.
- In August 2011, a rate application was filed with the OEB for permission to increase THC's regulated electricity distribution rates for three separate, consecutive years effective May 2012, 2013 and 2014.
- This application sought approval for distribution rates to be derived from a cost-of-service framework as the Company felt that large capital spending toward regulated infrastructure would be required for system upgrades.
- On January 5, 2012, the OEB ruled against the Company's application, stating that the evidences submitted failed to meet the Preliminary Issue test. As a result, the Company is expected to operate under the IRM framework for the May 2012 to May 2014 period as suggested by the OEB.

Financial Reporting

- The Canadian Accounting Standards Board (CASB) ruled in February 2008 that all public Canadian companies would be required to adopt International Financial Reporting Standards (IFRS) starting January 1, 2011.
- The International Account Standards Board (IASB) received a number of opinions which differed from their own on a variety of regulations imposed under this impending IFRS implementation.
- Due to the continued uncertainty surrounding IFRS in 2011, permission was granted from the applicable Canadian securities regulators as well as the Company's board of directors to begin looking at transitioning to U.S. GAAP.
- THC has indicated that the first report under U.S. GAAP will be in March 2012. DBRS expects that this standards change will be generally consistent with Canadian GAAP (currently used), and the Company will experience no material changes to operations or credit metrics as a result.

Description of Operations



As of December 31, 2011

- Toronto Hydro Corporation is a holding company with the following two subsidiaries operating exclusively in the Toronto area:
  - Toronto Hydro-Electric System Limited, one of the largest municipal distribution utilities in Canada, is responsible for regulated electricity distribution (99% of revenue).
  - Toronto Hydro Energy Services Inc. (which has a contractual relationship with the City of Toronto) owns and operates street lighting services (1% or revenue).
- Energy is generated by Ontario Power Generation Inc. (rated A (low)) and then transmitted to Toronto Hydro Corporation's networks by Hydro One Inc. (rated A (high)). From here, THC distributes the power to its customers via overhead and underground lines.
- The Company employs approximately 1,800 people, has a peak load of 5,000 megawatts and distributes electricity to over 700,000 customers (approximately 19% of the market in Ontario (rated AA (low)).
- The customer mix is heavily weighted toward residential consumers (89%), followed by general service (11%) and large users (less than 1%).

Toronto Hydro Corporation

Report Date:
January 20, 2012

Toronto Hydro Corporation

Balance Sheet ($ thousands - CAD)	Sept. 30	Dec. 31	Dec. 31		Sept. 30	Dec. 31	Dec. 31
Assets	**2011**	**2010**	**2009**	**Liabilities & Equity**	**2011**	**2010**	**2009**
Cash & equivalents	153,953	330,151	211,370	S.T. borrowings	0	0	0
Accounts receivable	220,968	168,988	150,795	Accounts payable	389,776	373,543	318,317
Inventories	7,365	7,501	6,224	Current portion L.T.D.	245,057	245,057	0
Prepaid expenses & other	290,890	298,670	314,910	Deferred tax	0	0	0
Total Current Assets	**673,176**	**805,310**	**683,299**	Other current liab.	38,540	21,785	19,895
				Total Current Liab.	**673,373**	**640,385**	**338,212**
Net fixed assets	2,321,436	2,128,777	1,919,954	Long-term debt	1,165,348	1,164,780	1,210,590
Future income tax assets	207,491	256,147	253,149	Deferred income taxes	0	0	0
Goodwill & intangibles	106,008	85,996	73,829	Other L.T. liab.	457,237	524,317	512,171
Investments & others	79,867	92,631	128,996	Shareholders equity	1,092,020	1,039,379	998,254
Total Assets	**3,387,978**	**3,368,861**	**3,059,227**	**Total Liab. & SE**	**3,387,978**	**3,368,861**	**3,059,227**

Balance Sheet &	9 mos.ending Sept. 30		12 mos.	For the year ended December 31				
Liquidity & Capital Ratios (1)	**2011**	**2010**	**Sept. 30**	**2010**	**2009**	**2008**	**2007**	**2006**
Current ratio	1.00	2.33	1.00	1.26	2.02	1.37	2.12	1.44
Net debt in capital structure	53.5%	50.5%	53.5%	51.0%	50.0%	46.9%	51.6%	49.6%
Total debt in capital structure	56.4%	58.0%	56.4%	57.6%	54.8%	55.2%	56.5%	57.5%
Adj. total debt in capital structure*	56.6%	58.1%	56.6%	58.5%	55.4%	55.8%	57.2%	58.0%
Cash flow/total debt	17.4%	17.3%	17.8%	17.9%	18.3%	19.3%	16.6%	21.4%
Cash flow/adj. total debt	17.2%	17.2%	17.7%	17.3%	17.9%	18.8%	16.1%	20.9%
(Cash flow - dividends)/capex (2)	0.51	0.68	0.48	0.58	0.79	0.54	0.53	1.14
Dividend payout ratio	35.4%	35.3%	40.0%	41.7%	59.7%	171.1%	70.6%	39.6%
Coverage Ratios (times) (3)								
EBIT interest coverage	2.31	2.12	2.20	2.05	1.73	1.77	2.07	2.66
EBITDA interest coverage	4.13	4.24	4.19	4.27	3.86	3.81	3.90	4.40
Fixed-charge coverage	2.31	2.15	2.21	2.10	1.77	1.93	2.27	3.22
Adjusted EBIT interest coverage*	2.31	2.12	2.20	2.09	1.76	1.80	2.09	2.67
Profitability Ratios								
EBITDA margin	11.4%	12.4%	11.7%	12.5%	12.0%	12.3%	13.1%	15.4%
EBIT margin	6.4%	6.2%	6.2%	6.0%	5.4%	5.7%	6.9%	9.3%
Profit margin	3.5%	2.6%	3.0%	2.3%	1.7%	2.9%	2.8%	5.2%
Return on equity	9.2%	6.7%	7.8%	5.9%	4.3%	7.1%	7.2%	13.4%
Return on capital	5.8%	4.9%	5.3%	4.6%	4.0%	5.3%	5.3%	8.0%

(1) Minority interests treated as equity equivalents. (2) Capital expenditures excluding acquisitions and equity investments.
(3) Before capitalized interest is deducted.
*Including operating leases.

Toronto Hydro Corporation

Report Date:
January 20, 2012

Rating

Debt	Rating	Rating Action	Trend
Short-Term Issuer Rating	R-1 (low)	Confirmed	Stable
Senior Unsecured Debentures & Medium Term Notes	A (high)	Confirmed	Stable

Rating History

	Current	2011	2010	2009	2008
Short-Term Issuer Rating	R-1 (low)	R-1 (low)	R-1 (low)	R-1 (low)	R-1 (low)
Senior Unsecured Debentures & Medium Term Notes	A (high)	A (high)	A (high)	A (high)	A

Note:
All figures are in Canadian dollars unless otherwise noted.

Rating Report

Report Date:
September 7, 2012

Previous Report:
June 19, 2012

Insight beyond the rating.

Toronto Hydro Corporation

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The Company

Toronto Hydro Corporation is a holding company with the following subsidiaries: Toronto Hydro-Electric System Ltd., which distributes electricity; and Toronto Hydro Energy Services Inc., which provides street lighting, expressway lighting services, and energy-efficient products and services. Toronto Hydro's sole shareholder is the City of Toronto (rated AA).

Recent Actions

January 20, 2012
Confirmed

Rating

Debt	Rating	Rating Action	Trend
Short-Term Issuer Rating	R-1 (low)	Confirmed	Stable
Senior Unsecured Debentures & MTNs	A (high)	Confirmed	Stable

Rating Update

DBRS has confirmed the rating of the Senior Unsecured Debentures & MTNs and Short-Term Issuer Rating of Toronto Hydro Corporation (THC or the Company) at A (high) and R-1 (low), respectively. The trends are both Stable. The rating confirmations reflect the continued stable earnings contribution from THC's regulated distribution business and its reasonable credit profile.

On May 10, 2012, THC filed its application to set electricity distribution rates for the 2012, 2013 and 2014 rate years under the Incentive Regulation Mechanism (IRM) framework. Under the IRM framework, the Company's actual rate of return on equity (ROE) in the next rate period is expected to weaken from the current allowed level of 9.58%, due to challenges associated with restructuring charges.

As the Company continues to refurbish its electricity distribution infrastructure to improve reliability, capital expenditures are expected to be well over the Company's current depreciation level. In light of the IRM framework, the Company will be required to manage its capital program effectively within its regulatory limits, which could be challenging given THC's aging infrastructure. The Company filed an incremental capital module (ICM) application in which it sought funding for capex of approximately $450 million to $500 million annually for the 2012 to 2014 period in order to maintain system reliability.

The confirmation incorporates DBRS's expectation that the Company remains committed to maintaining its debt-to-capital ratio in line with the regulatory 60% debt-to-40% equity structure. This capital structure is expected to allow THC to spend approximately $300 million to $350 million annually on capex with reasonable rate increases. DBRS notes that THC's leverage has increased over the years from approximately 55% in 2009 to 60% in the second quarter of 2012. Any additional significant increase in leverage or weakening of key credit metrics could cause THC's credit risk profile to deteriorate to a level that is no longer commensurate with the current A (high) rating.

Rating Considerations

Strengths

(1) Reasonable regulatory environment
(2) Strong franchise area
(3) Reasonable financial profile

Challenges

(1) Aging infrastructure
(2) Earnings sensitive to volume
(3) Low electricity consumption growth
(4) Limited access to equity markets

Financial Information

	USGAAP	USGAAP	Mix	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP
Toronto Hydro Corporation	**6 mos. June. 30**		**12 mos. June. 30**	**For the year ended December 31**				
(CA$ millions where applicable)	**2012**	**2011**	**2012**	**2011**	**2010**	**2009**	**2008**	**2007**
EBIT gross interest coverage	2.46	2.07	2.38	2.19	2.10	1.73	1.77	2.07
Total debt in capital structure (1)	59.9%	57.8%	59.9%	59.7%	58.5%	55.4%	55.8%	57.2%
Cash flow/Total debt	14.7%	19.2%	14.9%	16.8%	17.9%	18.3%	19.3%	16.6%
(Cash flow-dividends)/Capex (times)	0.64	0.56	0.49	0.49	0.58	0.79	0.54	0.53
Net income before non-recurring items	47	47	94	93	61	43	68	66
Cash flow from operations	108	135	219	246	253	222	233	200

(1) Including operating leases.

Toronto Hydro Corporation

Report Date:
September 7, 2012

Rating Considerations

Strengths

(1) **Reasonable regulatory environment.** THC is predominantly a regulated electric distribution company that operates in a reasonable regulatory environment. The Company's regulated business model provides a high degree of stability to earnings and cash flow over the long term.

(2) **Strong franchise area.** THC is one of the largest municipally-owned local distribution companies (LDCs) in Canada, serving a customer base of approximately 712,000 users. Approximately 90% of THC's electricity throughput is to residential and general service customers. Demand from these customers is relatively stable year over year, as they are less sensitive to economic cycles than large users (10% of demand).

(3) **Reasonable financial profile.** The Company's key credit metrics remain reasonable for its rating category. The confirmation incorporates DBRS's expectations that the Company remains committed to maintaining its debt-to-capital ratio in line with the regulatory 60% debt-to-40% equity structure, and that in the event that debt leverage rises above the regulated capital structure, the Company will take necessary measures to restore its structure to the 60% debt level in a timely manner.

Challenges

(1) **Aging infrastructure.** It is expected that over the next five to nine years, approximately 30% of the Company's assets will be nearing the end of their serviceable life, with some assets in operation beyond this point. Although the Company has been in line with industry standards, as measured by their System Average Interruption Duration Index (SAIDI) and System Average Interruption Frequency Index (SAIFI), approximately 40% of the downtime represented in these indicators is from defective equipment. Given the likelihood of moving to IRM and the probability of a reduced capex budget, THC will have to be very strategic on how it allocates its capex programs going forward.

(2) **Earnings sensitive to volume.** Earnings and cash flow for electricity distribution companies are partially dependent on the volume of electricity sold, given that rates typically include a variable charge component. Seasonality, economic cyclicality and weather variability have a direct impact on the volume of electricity sold and, therefore, on revenue earned from electricity sales.

(3) **Low electricity consumption growth.** THC has been experiencing low distribution volume growth, partly due to energy conservation initiatives and the negative impacts of the recent economic recession. The average load growth has been less than 1% over the past five years.

(4) **Limited access to equity markets.** THC's ownership structure (100% owned by the City of Toronto) limits its ability to access the equity markets directly. As a result, THC's additional cash flow needs are being financed largely through its retained earnings and debt issuances.

Toronto Hydro Corporation

Report Date:
September 7, 2012

Earnings and Outlook

(CA$ millions where applicable)	USGAAP 6 mos. June. 30 2012	USGAAP 6 mos. June. 30 2011	Mix 12 mos. June. 30 2012	CGAAP For the year ended December 31 2011	CGAAP 2010	CGAAP 2009	CGAAP 2008	CGAAP 2007
Net Sales	282	282	570	571	549	504	496	498
EBITDA	164	151	341	327	326	295	292	307
EBIT	93	82	188	176	157	132	136	163
Gross interest expense	38	39	79	81	75	77	77	79
Earning before taxes	57	45	113	101	86	62	74	103
Net income before non-recurring items	47	47	94	93	61	43	68	66
Reported net income	29	50	75	96	66	42	169	83
Return on equity	8.5%	8.9%	8.6%	8.7%	6.0%	4.3%	7.1%	7.3%

2011 Summary

- Net income before extraordinary items was higher year over year as a result of (1) a growing regulated rate base and (2) lower depreciation and amortization charges of $18.4 million, mainly due to the extension of the useful life of property, plant and equipment. This was partially offset by higher operating expenses (operating labour costs due to accounting changes).

Electricity Throughputs (million GWh)	%	2011	2010	2009	2008	2007
Residential	21%	5,204	5,209	5,037	5,216	5,332
General service	69%	17,148	17,318	16,855	17,415	17,837
Large users	10%	2,355	2,219	2,462	2,508	2,591
Total (million kWh)	100%	24,708	24,746	24,354	25,139	25,760
Growth in electricity throughputs		(0.2%)	1.6%	(3.1%)	(2.4%)	0.9%

Customers	%	2011	2010	2009	2008	2007
Residential	89%	629,049	620,501	611,357	605,509	601,515
General service	11%	80,222	79,836	78,840	78,589	78,349
Large users	0%	52	50	47	47	49
Total (million kWh)	100%	709,323	700,387	690,244	684,145	679,913
Growth in customer base		1.3%	1.5%	0.9%	0.6%	0.3%

As of December 31, 2011

2012 Outlook

- Net income before extraordinary items remained constant for the six months ended June 30, 2012 (H1 2012) compared to H1 2011. This was mainly due to lower operating expenses (as a result of cost reduction initiatives), which were offset by lower revenues, higher depreciation and higher income taxes.
- Under the IRM framework, the Company's actual rate of ROE in the next rate period will likely weaken from the current allowed level of 9.58%, due to challenges associated with the workforce restructuring program.
- THC spent $27.8 million for restructuring costs, of which $19.3 million remains unpaid as at June 30, 2012.

Toronto Hydro Corporation

Report Date:
September 7, 2012

Financial Profile and Outlook

	USGAAP	USGAAP	Mix	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP
	6 mos. June. 30		12 mos. June. 30	For the year ended December 31				
(CA$ millions where applicable)	**2012**	**2011**	**2012**	**2011**	**2010**	**2009**	**2008**	**2007**
Net income before non-recurring items	47	47	94	93	61	43	68	66
Depreciation & amortization	71	69	153	151	169	163	156	144
Deferred income taxes and other	(9)	20	(27)	2	22	16	9	(10)
Cash flow from operations	108	135	219	246	253	222	233	200
Dividends paid	(35)	(20)	(48)	(33)	(25)	(25)	(116)	(46)
Capital expenditures	(115)	(205)	(347)	(437)	(391)	(249)	(215)	(290)
Free cash flow (bef. working cap. changes)	(42)	(90)	(176)	(224)	(163)	(53)	(98)	(136)
Changes in non-cash work. cap. items	(24)	(52)	92	64	27	(31)	34	14
Net Free Cash Flow	(66)	(142)	(84)	(160)	(135)	(84)	(65)	(122)
Acquisitions & long-term investments	0	0	0	0	0	0	0	(88)
Short-term investments	34	(34)	34	(34)	50	0	0	0
Proceeds on asset sales	1	4	1	5	9	1	0	2
Net equity change	0	0	0	0	0	0	0	0
Net debt change	0	0	53	53	198	3	0	5
Other	(2)	(39)	(4)	(40)	(3)	(50)	189	92
Change in cash	(33)	(210)	1	(176)	119	(129)	124	(112)
Total debt	1,470	1,410	1,470	1,464	1,410	1,211	1,207	1,206
Cash and equivalents	121	120	121	154	330	211	340	216
Total debt in capital structure	57.3%	56.9%	57.3%	57.0%	57.6%	54.8%	55.2%	56.5%
Total debt in capital structure (1)	59.9%	57.8%	59.9%	59.7%	58.5%	55.4%	55.8%	57.2%
Cash flow/Total debt	14.7%	19.2%	14.9%	16.8%	17.9%	18.3%	19.3%	16.6%
Cash flow/Total debt (1)	13.2%	18.5%	13.4%	15.1%	17.3%	17.9%	18.8%	16.1%
EBIT gross interest coverage (times)	2.46	2.07	2.38	2.19	2.10	1.73	1.77	2.07
EBIT gross interest coverage (times) (1)	2.52	2.10	2.44	2.27	2.13	1.76	1.80	2.09
Dividend payout ratio	74.7%	43.0%	51.3%	35.4%	40.8%	59.2%	171.1%	69.9%

(1) Including operating leases.

2011 Summary

- THC's financial profile and key financial ratios remained reasonable for the assigned rating category.
- Dividends increased in 2011 as per the Company's shareholder direction adopted by the City of Toronto (the City), which states that the Company will pay the greater of $25 million per year (in segments throughout the year), or if applicable, 50% of any consolidated net income surpassing this amount.
- Free cash flow deficits continued in 2011, primarily due to increased levels of capex to modernize THC's aging electricity distribution infrastructure. This was financed with cash on hand and debt.

2012 Outlook

- THC's key credit metrics remained relatively stable in H1 2012. Capex was lower in H1 2012 than in H1 2011, primarily due to the uncertainty regarding electricity distribution rates for 2012.
- Dividends increased in H1 2012, following the City's direction. Out of the $35 million paid, $23 million was attributable to 2011 and $12 million was attributable to H1 2012. On August 17, 2012, the Company declared a dividend of $6 million for the third quarter of 2012.
- The free cash flow deficit was lower in H1 2012 than H1 2011, mainly due to lower capex. The deficit was funded by cash on hand.
- The Company will be required to manage its capital program effectively and within its regulatory limits. This could be a challenge in the medium term, due to its aging regulated electricity distribution infrastructure, which could require a costly and extensive refurbishment of the distribution network to maintain reliability.
- DBRS expects the Company to continue to maintain its leverage at 60%, in line with the OEB-approved deemed capital structure. If leverage rises above the OEB deemed capital structure (60% debt-to-40% equity) or if key credit metrics weaken significantly, THC's financial profile could deteriorate to a level that is no longer commensurate with the current A (high) rating.

Long-Term Debt Maturities and Bank Lines

(CA$ millions)	Amount	Draw/LOCs	Available	Expiry
Cash & Cash Equivalents	120.8	-	120.8	-
Revolving Credit Facility	400.0	-	400.0	May 3, 2013
Bilateral facility	50.0	45.6	4.4	Demand
		Total	**525.2**	

As at June 30, 2012

- The Company's liquidity profile remained strong and sufficient to cover all near- to medium-term obligations, with approximately $525.2 million of available funds.
- DBRS notes that THC does not currently have a commercial paper program.

Debentures

(CA$ millions)	Maturity	Outstanding
Series 1 - 6.11%	May 7, 2013	225.0
Series 2 - 5.15%	Nov 14, 2017	249.8
Series 3 - 4.49%	Nov 12, 2019	250.0
Series 5 - 6.11%	May 6, 2013	245.1
Series 6 - 5.54%	May 21, 2040	199.9
Series 7 - 3.54%	Nov 18, 2021	299.9
Total debentures		**1,469.6**
Less: Current portion of debentures		(470.0)
Long-term portion of debentures		**999.5**

As at June 30, 2012

Long-term Debt Maturities

(CA$ millions)	2012	2013	2014	2015	2016+	Total
Amount	-	470.0	-	-	999.5	1469.6
% of Total	0.0%	32.0%	0.0%	0.0%	68.0%	100.0%

As at June 30, 2012

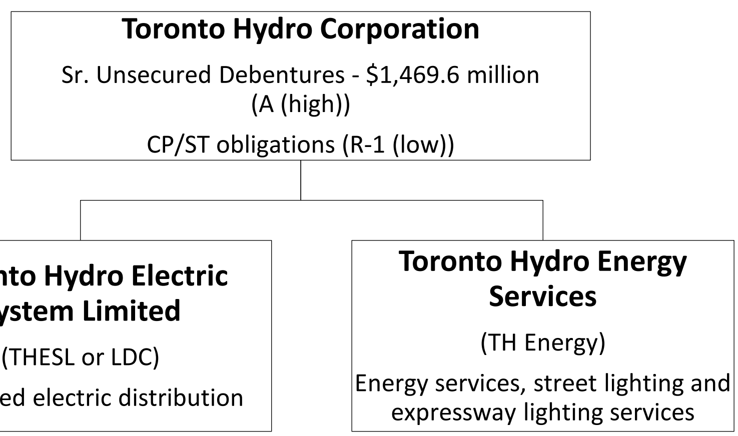
- While 32% of the long-term debt is maturing in 2013, DBRS does not believe refinancing will pose a problem for the Company, given its recent successes.
  – The Series 4 debenture with $254.1 million outstanding was refinanced in November 2011, with a 3.54% $300 million unsecured debenture (Series 7) maturing in November 2021.
- The Company has access to a shelf prospectus initiated on December 9, 2010, for the issuance of up to $1 billion, active for 25 months following this prospectus date.

Regulation

Provincial Regulation

- THC's regulated electricity distribution business is regulated by the OEB, whose mandate is to approve and set rates for the distribution and transmission of electricity as set out by the *Electricity Act, 1998*.
- THC operates with a deemed capital structure of 60% debt (divided into 56% long-term and 4% short-term) and 40% equity.
- In December 2009, the OEB changed its methodology for calculating ROE. The new formula adopted by the OEB provided for an allowed ROE of 9.58% for 2011, down from 9.85% in 2010.
- The new calculation is composed of a base ROE of 9.75% plus 50% of the change in the long-term Government of Canada Bond forecast from the base year, and 50% of the change in the spread of an A-rated bond index over the 30-year Canada bond yield.
- In August 2011, a rate application was filed with the OEB for permission to increase THC's regulated electricity distribution rates for three separate consecutive years, effective May of 2012, 2013 and 2014. The application sought approval for distribution rates to be derived from a cost-of-service framework, as the Company felt that large capex toward regulated infrastructure would be required for system upgrades.
- On January 5, 2012, the OEB ruled against the Company's application, stating that the evidence submitted failed to meet the Preliminary Issue test.
- On May 10, 2012, THC filed its application to set electricity distribution rates for the 2012, 2013 and 2014 rate years under the IRM framework. In the ICM, the Company sought funding for its total regulated capex of approximately $448.7 million in 2012, $534.5 million in 2013 and $439.5 million in 2014. The OEB decision is expected in the fourth quarter of 2012 or the first quarter of 2013.

Corporate Structure



- THC is a holding company with the following two subsidiaries operating exclusively in the Toronto area:
  - Toronto Hydro-Electric System Limited, one of the largest municipal distribution utilities in Canada, is responsible for regulated electricity distribution (99% of revenue).
  - Toronto Hydro Energy Services Inc. (which has a contractual relationship with the City) owns and operates street lighting services (1% of revenue).
- Energy is generated by Ontario Power Generation Inc. (rated A (low)) and then transmitted to THC's networks by Hydro One Inc. (rated A (high)). From here, THC distributes the power to its customers via overhead and underground lines.
- The Company currently employs approximately 1,600 people, has a peak load of approximately 5,000 megawatts and distributes electricity to over 712,000 customers (approximately 18% of the market in Ontario (rated AA (low)).
- The customer mix is heavily weighted toward residential consumers (89%), followed by general service (11%) and large users (less than 1%).

Toronto Hydro Corporation

Report Date:
September 7, 2012

Toronto Hydro Corporation

Balance Sheet	USGAAP	CGAAP	CGAAP		USGAAP	CGAAP	CGAAP
(CA$ millions)	**Jun. 30**	**Dec. 31**	**Dec. 31**		**Jun. 30**	**Dec. 31**	**Dec. 31**
Assets	**2012**	**2011**	**2010**	**Liabilities & Equity**	**2012**	**2011**	**2010**
Cash & equivalents	121	154	330	Accounts payable	397	412	374
Accounts receivable	192	183	169	Current portion L.T.D.	470	0	245
Inventories	6	7	8	Customer advanced deposits	44	20	19
Unbilled revenue	273	262	288	Deferred revenue	19	13	1
Prepaid expenses & other	30	50	11	Other current liab.	25	2	1
Total Current Assets	622	656	805	**Total Current Liab.**	956	448	640
Net fixed assets	2,428	2,399	2,129	Long-term debt	1,000	1,464	1,165
Future income tax assets	199	202	226	Deferred income taxes	198	200	225
Goodwill & intangibles	128	113	86	Provisions	245	184	175
Regulatory assets	136	77	85	Regulatory liabilities	4	10	49
Investments & others	12	7	8	Other L.T. liab.	28	47	46
				Shareholders' equity	1,096	1,102	1,039
Total Assets	3,526	3,456	3,339	**Total Liab. & SE**	3,526	3,456	3,339

	USGAAP	USGAAP	Mix	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP
Balance Sheet &	**6 mos. June. 30**		**12 mos. June. 30**		**For the year ended December 31**			
Liquidity & Capital Ratios	**2012**	**2011**	**2012**	**2011**	**2010**	**2009**	**2008**	**2007**
Current ratio	0.65	1.06	0.65	1.46	1.26	2.02	1.37	2.12
Total debt in capital structure	57.3%	56.9%	57.3%	57.0%	57.6%	54.8%	55.2%	56.5%
Total debt in capital structure (1)	59.9%	57.8%	59.9%	59.7%	58.5%	55.4%	55.8%	57.2%
Cash flow/Total debt	14.7%	19.2%	14.9%	16.8%	17.9%	18.3%	19.3%	16.6%
Cash flow/Total debt (1)	13.2%	18.5%	13.4%	15.1%	17.3%	17.9%	18.8%	16.1%
(Cash flow-dividends)/Capex (times)	0.64	0.56	0.49	0.49	0.58	0.79	0.54	0.53
Dividend payout ratio	74.7%	43.0%	51.3%	35.4%	40.8%	59.2%	171.1%	69.9%
Coverage Ratios (times)								
EBIT gross interest coverage	2.46	2.07	2.38	2.19	2.10	1.73	1.77	2.07
EBITDA gross interest coverage	4.32	3.82	4.31	4.06	4.37	3.86	3.81	3.90
Fixed-charges coverage	2.46	2.07	2.38	2.19	2.10	1.77	1.93	2.27
EBIT gross interest coverage (1)	2.52	2.10	2.44	2.27	2.13	1.76	1.80	2.09
Profitability Ratios								
EBITDA margin	58.2%	53.3%	59.7%	57.3%	59.4%	58.6%	59.0%	61.7%
EBIT margin	33.2%	28.9%	33.0%	30.9%	28.5%	26.3%	27.5%	32.8%
Profit margin	16.6%	16.5%	16.4%	16.4%	11.1%	8.4%	13.7%	13.3%
Return on equity	8.5%	8.9%	8.6%	8.7%	6.0%	4.3%	7.1%	7.3%
Return on capital	5.2%	5.6%	5.4%	5.4%	4.5%	4.1%	5.3%	5.4%

(1) Including operating leases.

Toronto Hydro Corporation

Report Date:
September 7, 2012

Rating

Debt	Rating	Rating Action	Trend
Short-Term Issuer Rating	R-1 (low)	Confirmed	Stable
Senior Unsecured Debentures & MTNs	A (high)	Confirmed	Stable

Rating History

	Current	2011	2010	2009	2008
Short-Term Issuer Rating	R-1 (low)	R-1 (low)	R-1 (low)	R-1 (low)	R-1 (low)
Senior Unsecured Debentures & MTNs	A (high)	A (high)	A (high)	A (high)	A

Note:
All figures are in Canadian dollars unless otherwise noted.

Toronto Hydro-Electric System Limited
EB-2012-0064
Tab 6C
Schedule 10-1
Appendix H
Filed: 2012 Oct 5
(4 pages)

STANDARD & POOR'S

Global Credit Portal®
RatingsDirect®

March 22, 2012

Summary:
Toronto Hydro Corp.

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Rationale

Outlook

Related Criteria And Research

Summary:
Toronto Hydro Corp.

Credit Rating: A/Stable/--

Rationale

The ratings on Toronto Hydro Corp., an Ontario-based utility holding company, largely reflect Standard & Poor's Ratings Services' view of the credit risk profile of the company's key subsidiary, Toronto Hydro-Electric System Ltd. (THESL; generating 97% of Toronto Hydro's consolidated net revenue). We believe THESL's excellent business risk profile reflects its monopoly, low-risk, regulated electricity distribution business and solid customer base. Offsetting these strengths is our view of Toronto Hydro's significant financial risk profile. Total reported debt outstanding at Toronto Hydro as of Dec. 31, 2011, was about C$1.46 billion. We expect that the company will focus on its core regulated local electricity distribution company (LDC) business without any material investment in nonregulated renewable generation in the medium term.

In our view, THESL's monopoly position and the asset-intensive nature of electricity distribution limit competitive risk. The electricity distribution business carries relatively low operating risk. Operational efficiency and reliability are within provincial industry norms, avoiding regulatory risk linked to poor performance. Toronto Hydro is one of Ontario's largest LDCs, with about C$2.4 billion in capital assets and delivering almost 20% of the electricity used in the province.

We believe the Ontario Energy Board's (OEB) regulatory framework supports THESL's cash-flow stability. The framework allows for the recovery of prudent costs and the opportunity to earn a modest return. Electricity market design and a regulated and timely commodity cost pass-through mechanism limit the company's exposure to commodity risk. Since the obligation to ensure an adequate electricity supply for its customers lies with the OPA, THESL's balance sheet is not burdened with power purchase contractual obligations. On Jan. 5, 2012, the OEB declined to hear THESL's cost-of-service application for 2012 in advance of 2015, and instead directed the company to file for a 2012 rate increase based on the OEB's incentive regulatory mechanism formula. The formula allows for inflation but also expects some offsetting productivity improvements in each year of a three-year cycle; THESL is in year 2. We believe the decision is rating neutral; it was not unexpected and we still expect the company to meet our credit metric targets for the rating. THESL has taken action to slow its planned capital program, and we expect spending will remain in line with OEB-approved levels for cost recovery.

Further supporting cash flow stability are THESL's solid customer base and the essential nature of the service provided. In our opinion, the Greater Toronto Area's economy is deep and well-diversified, although not immune to economic downturns. Finance, manufacturing, and business and professional services are the foundations of the city's economy. Exposure to large users, with a monthly peak demand of more than 5 megawatts, represents less than 10% of gross revenue. Further protecting its customer base is the provision of an essential service and that the cost to residential customers of producing their own power remains economically inaccessible to most. Toronto is Canada's largest city and our long-term view is that it will weather economic slowdowns. New time-of-use rates facilitated by recently installed smart meters encourage customers to shift the time of consumption to reduce their commodity costs, but we don't expect these to materially affect THESL's net distribution revenues.

In our view, the stable and predictable, but highly-leveraged, asset-intensive business supports a significant financial risk profile. The company has had favorable access to debt capital markets. Its key financial metrics in 2011 were very similar to the historical range, in our view. We expect Toronto Hydro to continue to achieve about 14%-15% of AFFO-to-total debt in 2012 and 2013 and that management will maintain its balance sheet consistent with the regulatory deemed structure.

We base our 'A' rating on Toronto Hydro's stand-alone credit risk profile and our opinion that there is "low" likelihood that its owner, the City of Toronto (AA/Stable/A-1+), would provide timely and sufficient extraordinary support in the event of financial distress. We assess the company's stand-alone credit profile at 'a'. In accordance with our criteria, we view its role as of "limited importance" and the link between the utility and its owner as "limited."

Liquidity

We believe Toronto Hydro's liquidity is adequate, as per our criteria, to cover its needs in the near term, even in the event of an unforeseen earnings decline. In our assessment, we incorporate the following assumptions:

- The company's liquidity sources, including cash, our estimated FFO, and its revolving credit facility, will likely exceed uses 1.2x or more in the next 12 months.
- We expect net sources to remain positive, even in the event of a highly unlikely EBITDA decline of more than 15%.
- Liquidity sources include our expectation of C$240 million-C$250 million of annual FFO and its access to a fully available C$400 million revolving credit facility (expiring May 2013) as of Dec. 31, 2011.
- Liquidity uses include our estimated annual capital expenditure of about C$300 million-C$400 million and typical dividend payment of 50% of net income (C$35 million-$40 million). There is no maturing debt until May 2013.

The utility is well within the financial covenants applicable to its credit facility.

Outlook

The stable outlook reflects our expectation that Toronto Hydro will maintain its capital structure in line with the regulatory deemed capital structure, manage its capital expenditure in line with OEB-approved levels for cost recovery, and remain focused on its regulated electricity distribution business. A material adverse energy policy change or an expectation of sustained financial deterioration (12% of AFFO-to-debt or less and 60% of reported total debt–to-total capital or higher) will likely lead to a negative rating action. An upgrade is unlikely without a demonstrated, long-term, expectation of deeper cash flow interest and debt coverage (greater than 30% of AFFO-to-total debt), which we believe would likely require a material change in financial policy.

Related Criteria And Research

- Methodology And Assumptions: Liquidity Descriptors For Global Corporate Issuers, Sept. 28, 2011
- Rating Government-Related Entities: Methodology And Assumptions, Dec. 9, 2010
- Criteria Methodology: Business Risk/Financial Risk Matrix Expanded, May 27, 2009
- Key Credit Factors: Business And Financial Risks In The Investor-Owned Utilities Industry, Nov. 26, 2008
- 2008 Corporate Criteria: Analytical Methodology, April 15, 2008

STANDARD & POOR'S RATINGS SERVICES

RatingsDirect®

Toronto Hydro Corp.

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Toronto Hydro Corp.

Major Rating Factors

Corporate Credit Rating
A/Stable/--

Strengths:

- Monopoly position that limits competitive risk
- Stable cash flows from a low-risk, regulated electricity distribution business
- Favorable service territory

Weaknesses:

- Significant financial risk profile
- Sizable capital expenditures pressure related to aging infrastructure

Rationale

The ratings on Toronto Hydro Corp., an Ontario-based utility holding company, reflect Standard & Poor's Ratings Services' view of the credit risk profile of the company's key subsidiary, Toronto Hydro-Electric System Ltd. (THESL; it generates 97% of Toronto Hydro's consolidated net revenue). We believe THESL's excellent business risk profile reflects its monopoly, low-risk, regulated local electricity distribution business and solid customer base. Offsetting these strengths is our view of Toronto Hydro's significant financial risk profile and sizable capital expenditures pressure related to aging infrastructure. Total reported debt outstanding at the company as of June 30, 2012, was about C$1.47 billion.

We base our 'A' rating on Toronto Hydro's stand-alone credit risk profile of 'a' and our opinion that there is a "low" likelihood that its owner, the City of Toronto (AA/Stable/A-1+), would provide timely and sufficient extraordinary support in the event of financial distress. In accordance with our criteria, we view the utility's role as of "limited importance" and the link between the utility and its owner as "limited."

In our view, THESL's monopoly position and the asset-intensive nature of electricity distribution limit competitive risk. The electricity distribution business carries relatively low operating risk. We expect operational efficiency and reliability to remain within provincial industry norms, avoiding regulatory risk linked to poor sustained performance.

We believe the Ontario Energy Board's (OEB) regulatory framework will continue to support THESL's cash-flow stability. Under the framework we expect the utility to recover prudent costs (including costs of debt) and earn a modest return on capital invested. Electricity market design and a regulated and timely commodity cost pass-through mechanism limit the company's exposure to commodity risk, in our view. Since the obligation to ensure an adequate electricity supply for its customers lies with the government agency, the Ontario Power Authority, THESL's balance sheet is not burdened with power purchase contractual obligations. In our view, the OEB has exhibited increased scrutiny of requested cost increases in the distribution sector and the associated rate pressure on customers. While we expect tempering rate increases will remain an important regulatory consideration, we believe the OEB will continue to honor its mandate to balance the ability of the utilities to earn a modest return with the needs of customers. The fact that distribution costs typically represent about 25% of the total energy bill supports this view.

Further supporting cash flow stability are THESL's solid customer base, which is largely residential, and the service's essential nature. In our view, distribution revenues (net of commodity pass through) are subject to modest volumetric risk, largely due to weather and, to a less extent, economic conditions, given its limited exposure to large cyclical industrial customers. For example, volatility of distribution revenues (net of commodity pass through) has been modest historically, including the recession, at approximately plus or minus 5%. In our opinion, the Greater Toronto Area's economy is deep and well-diversified, although not immune to economic downturns. Finance, manufacturing, and business and professional services are the foundations of the city's economy. Further protecting the customer base is the provision of an essential service and that the cost to residential customers of producing their own power remains economically inaccessible to most. New time-of-use rates facilitated by recently installed smart meters encourage customers to shift the time of consumption to reduce their commodity costs, but we don't expect these to materially affect THESL's distribution revenues (net of commodity pass through).

In our view, the stable and predictable, but highly-leveraged, asset-intensive business will continue to support a significant financial risk profile. Our forecasts assume that the company will maintain its capital structure in line with the regulatory deemed capital structure of a 60% debt layer, manage its capital expenditures in line with OEB-approved levels, and remain focused on its core regulated local electricity distribution company business. Based on these assumptions, we expect Toronto Hydro will achieve 14%-16% of adjusted funds from operations (AFFO)-to-total debt and remain in line with our downgrade threshold of 12% of AFFO-to-total debt and reported total debt-to-total capital of 60% in 2013 and 2014.

Liquidity

In accordance with our criteria, we consider Toronto Hydro's liquidity as adequate. Standard & Poor's assessment of the company's liquidity profile incorporates the following expectations and assumptions.

- Toronto Hydro's liquidity sources will likely exceed its uses by 1.2x or more in the next six months.
- Liquidity sources include our expectation of about C$240 million to C$250 million of annual FFO, its access to C$400 million revolving credit facility (expiring May 2013; fully available as of June 30, 2012) and C$121million cash on hand as of June 30, 2012.
- Liquidity uses include an annual capital expenditure of about C$140 million (the OEB's currently approved capital expenditure amount). We did not include maturing debt of C$470 million (due May 2013) since their maturity dates are beyond our six-month horizon. Nevertheless, we understand that the company will take active steps to secure sources to refinance its maturing debt in a timely manner.

As of June 30, 2012, Toronto Hydro was within the financial covenants. Historically, the Canadian debt market has demonstrated strong demand for regulated utilities. Therefore, we do not have any meaningful rating concern about the utility's ability to access the debt market and complete refinancing in a timely manner. In our view, the company has sound relationships with banks.

Outlook

The stable outlook reflects our assessment of stable cash flows from Toronto Hydro's low-risk regulated monopoly electricity distribution business and our expectation that the company will manage its capital expenditure in line with OEB-approved levels. A material adverse energy or regulatory policy change or an expectation of sustained financial deterioration (12% of AFFO-to-debt or less and 60% of reported total debt–to-total capital or higher) would likely lead to a downgrade. An upgrade is unlikely without a demonstrated, long-term expectation of deeper cash flow debt coverage (greater than 30% of AFFO-to-total debt), which we believe would likely require a material change in financial policy.

Business Description

Toronto Hydro is a utility holding company. Its primary operation is THESL's monopoly electricity distribution business, which delivers electricity throughout Toronto. THESL represents about 97% of Toronto Hydro's fixed assets and distribution revenues (net of commodity pass-through) in 2011. It is one of Ontario's largest local distribution companies (LDCs), with about C$2.4 billion in fixed assets and delivering almost 20% of the electricity used in the province.

Government Support And Government-Related Entities Methodology: No Impact On The Ratings

In accordance with our criteria for government-related entities (GREs), we base our view of a "low" likelihood of extraordinary government support on the following assessment.

Within the context of our GRE methodology and scale for assessing the importance of a GRE's role to its government owner, we view Toronto Hydro's role as of "limited importance" to the city. Although the utility provides an essential and monopolistic service, we believe a default is not likely to pose a material risk to its own continuing physical operations or to the city's economy or government processes. Furthermore, electricity policy is set at the provincial level.

Within the context of our GRE methodology and scale for assessing strength and durability, we view the link between Toronto Hydro and the city as "limited." In our view, Toronto does not interfere with the company's day-to-day operations. The city has limited financial capacity and no formal policy to provide financial support to the company in a timely manner. Its current consideration of a potential sale of its 10% interest in Toronto Hydro also might indicate less likelihood of its financial support and capacity to the company.

Excellent Business Risk Profile

Regulatory framework supports a stable and predictable cash flow

We believe the Ontario regulatory framework governing the LDC's electricity distribution pricing is relatively independent, transparent and consistent, providing cash flow stability to Toronto Hydro. Regulated rates are based on an OEB-approved revenue requirement and the company's load forecast. The revenue requirement is based on cost-of-service (CoS) and rate-of-return methodology that generally allows THESL to recover all prudent costs and to earn a return on capital invested. In setting rates, the regulator reviews the company's forecast costs, and allows for a return based on a deemed capital structure of 60% debt and 40% equity. The allowed economic return is based on a formula linked to long-term Government of Canada (AAA/Stable/A 1+) bonds and utility bond spreads. The actual cost of debt is included in forecast costs.

Since 2006, the company's strategy has been to rebase its rate base every year through a CoS application, more frequently than a usual four-year cycle, in view of its heavy capital expenditure needs to address an aging infrastructure issue. This strategy was to mitigate the potential time lag between its capital expenditure spending and cost recovery through rate-base adjustments. The OEB accepted this approach until January 2012, when it declined to hear the company's CoS application in advance to 2015. We view the OEB decision as rating neutral; it was not unexpected and we do not consider it as an indication of an unsupportive regulatory regime. Rather, this is about disagreement between Toronto Hydro and the OEB on the pace of replacing aging infrastructure, not on needs of replacing aging infrastructure, in our view. In May 2012, the company submitted another rate application requesting capital expenditures of next two years higher than depreciation but lower than those under its initial CoS application. It is waiting for the OEB decision. From a credit perspective, we believe the impact of the OEB's upcoming decision on Toronto Hydro's key financial measures should be neutral since we expect the company will spend capital expenditures in line with the OEB pre-approved levels with associated cost recovery and continue to manage its capital structure within the regulatory deemed capital structure of a 60% debt layer.

A mature and primarily residential customer base adds to credit stability

Supporting Toronto Hydro's excellent business risk profile is the stable service franchise of its regulated electricity distribution business. The company distributes electricity in Toronto, the Canada's largest city which has a well-diversified economy base. The LDC's customer base is predominantly residential and not heavily influenced by cyclical energy consumers, which we view as supporting credit. The utility provides electricity to about 720,000 customers, of which about 630,000 are residential, in a small geographic area. Toronto Hydro's large industrial users (with monthly peak demand of greater than 5 megawatts [MW]) segment accounts for less than 10% of distribution revenues (net of commodity pass-through).

Low-risk operation

We view electricity distribution business has relatively low operating risk compared to generation. Despite the company has an aging infrastructure issue, the operational performance of its electricity distribution assets remains relatively steady and in line with that of its Canadian utilities peers. The regulator tracks performance metrics but has not yet imposed generic industry standards or penalties for substandard service, which eliminates the negative impact on key financial measures driven by potential substandard service.

Minimal competitive risk exposure

Toronto Hydro's natural monopoly electricity distribution business largely shields it from direct competition. The company's cost-competitive network pricing mitigates the incentive for bypass of the distribution network. Competitive risk is minimal, in our opinion, given the large capital cost involved in duplicating the asset-intensive distribution system.

Other activities are not material to the ratings

We expect that THESL's regulated electricity distribution business will continue to dominate Toronto Hydro's operations and cash flows. Its other activities include the unregulated provision of street lighting and energy engineering solutions primarily to its government shareholder; these account for 5% or less of cash flow.

Although the LDC is allowed to participate in developing and operating contracted renewable electricity generation aligned with the Green Energy Act, we understand that the company has no known commitments related to renewable electricity generation to date. We believe two small potential cogeneration projects, Ashbridges Bay (10 MW) and Green Lane (10 MW), are on hold due to transmission connection issues. Our rating assumes that Toronto Hydro's investments in nonregulated renewable generation, if any, will remain small, at less than 10% of its consolidated FFO, EBITDA, or total asset value in the long term.

Significant Financial Risk Profile

Accounting

Toronto Hydro prepared consolidated financial statements in accordance with Canadian generally accepted accounting principles (GAAP) until 2011. The Canadian Accounting Standards Board has called for a convergence to International Financial Reporting Standards (IFRS) by 2013 (effective Jan. 1, 2013). Similar to Hydro One and other large regulated utilities, the company decided to adopt U.S. GAAP, effective Jan 1, 2012 to avoid reporting volatile earnings as IFRS does not allow the recognition of regulatory assets and liabilities on the balance sheet statement. The change in accounting practice itself should not affect Standard & Poor's credit analysis.

Pension obligations fall to a third party. THESL recovers annual payments to OMERS Administration Corp., its pension provider, through regulated cost-of-service determinations. Therefore, we do not adjust the company's pension obligation. However, we have adjusted the balance sheet related to other postretirement benefit obligations, which account for approximately 10% of total adjusted debt.

Financial policies comparable with those of peers

Regulatory practice, including a 40% deemed equity component for THESL, guide the level of leverage at the key subsidiary. Toronto Hydro's dividend policy, which it adopted in 2004, is to distribute the greater of 50% of its consolidated net income or C$25 million. The city relies on the company's board of directors to assess Toronto Hydro's ability to pay dividends, including assessing how any dividend payment might affect its financial risk profile and our ratings. The shareholder direction indicates that management should target a rating of 'A-' or better.

The regulatory compact largely constrains profitability

The utility's profitability largely reflects the OEB's decisions on its rate applications, including rate base, revenue requirement, return on equity and deemed equity. Other factors (of which influence is not as material as the OEB rate case decisions) include the company's cost management and customer electricity consumption driven by weather, conservation efforts, economic conditions and customer growth. We believe the impact of reduced consumption will not affect profitability on a sustained basis, given the LDC's ability to update its load forecast in CoS applications.

Although Toronto Hydro's key financial measures fall in an aggressive category, we view the company's financial risk profile as significant because, in our view, regulatory support continues to provide secure and predictable cash flows. Variability in AFFO-to-debt has been historically very low at less than plus or minus 2%. Assuming that the OEB will approve Toronto Hydro's recent rate application without material disallowances, we forecast that its AFFO-to-debt will remain above our downgrade threshold of 12%, at 14%-16% in 2013 and 2014. We also expect to see modest increases in its cash flows driven by rate-riders (in other words, additional charges in existing rates) associated with capital expenditures during this period. We believe the company will spend only the OEB preapproved capital expenditures in 2013 and 2014 because there is no economic incentive to spend capital expenditures without associated cost recovery or earning returns.

The capital structure at THESL is likely remain in line with the regulatory deemed capital structure

We expect its leverage to remain within the regulatory deemed capital structure of a 40% equity layer on a reported basis in the foreseeable future. In its tariff determinations for THESL, the OEB imputes an equity layer of 40%. There is little financial incentive for Toronto Hydro to materially vary from this level, because any additional equity at the subsidiary level would generate a lower return (equal to the cost of debt) than the allowed return on equity. Given that THESL accounts for 97% of Toronto Hydro's capital assets, we expect Toronto Hydro's capital structure will be very similar to that of THESL.

No interest rate or foreign exchange exposure

The nature of the company's debt and its long-lived assets and the ability to recover interest expense through regulated rates limit the company's financial risk exposure. All long-term debt is at a fixed rate and we believe upcoming maturities should be manageable. The OEB will generally allow THESL to recoup the market cost of debt. Furthermore, as all issues are in domestic currency, the company faces no meaningful foreign exchange exposure.

Table 1

Toronto Hydro Corp.--Peer Comparison

Industry Sector: Electric Utility

	--Fiscal year ended Dec. 31, 2011--				
(Mil. C$)	**Toronto Hydro Corp.**	**Hydro One Inc.**	**PowerStream Inc**	**Hydro Ottawa Holding Inc.**	**Enersource Corp.**
Rating as of Sept. 20, 2012	A/Stable/--	A+/Negative/A-1	A/Stable/--	A/Stable/--	A/Stable/--
Revenues	2,809.3	5,471.0	922.4	840.1	816.6
EBITDA	336.8	1,893.3	107.5	92.6	68.1
Net income from continuing operations	95.9	641.0	30.3	26.2	22.7
Funds from operations (FFO)	252.6	1,124.6	85.3	73.3	57.3
Capital expenditures	432.1	1,398.9	90.7	77.2	43.5
Free operating cash flow	(115.4)	(78.3)	(22.0)	(0.8)	23.6
Dividends paid	33.1	168.0	13.9	17.5	10.6
Cash and short-term investments	154.3	228.0	0.0	2.9	107.1
Debt	1,711.7	9,591.0	459.5	260.4	321.8
Preferred stock	0.0	323.0	0.0	0.0	0.0
Equity	1,055.8	5,472.5	300.7	350.2	249.1
Debt and equity	2,767.5	15,063.4	760.2	610.5	570.9
Adjusted ratios					
FFO interest coverage (x)	3.5	3.2	4.1	6.5	4.0
FFO/debt (%)	14.8	11.7	18.6	28.2	17.8
Debt/EBITDA (x)	5.1	5.1	4.3	2.8	4.7
Total debt/debt plus equity (%)	61.9	63.7	60.4	42.6	56.4

Table 1

Toronto Hydro Corp.--Peer Comparison (cont.)					
Common dividend payout ratio (unadjusted; %)	34.5	24.1	45.7	66.8	46.7

Table 2

Toronto Hydro Corp.--Financial Summary

Industry Sector: Electric Utility

	--Fiscal year ended Dec. 31--				
(Mil. C$)	**2011**	**2010**	**2009**	**2008**	**2007**
Rating history	A/Stable/--	A/Stable/--	A/Stable/--	A/Stable/--	A-/Positive/--
Revenues	2,809.3	2,611.7	2,461.7	2,382.5	2,389.2
EBITDA	336.8	332.3	301.8	298.4	329.0
Net income from continuing operations	95.9	66.1	42.8	46.3	58.6
Funds from operations (FFO)	252.6	253.1	218.7	229.5	229.0
Capital expenditures	432.1	388.5	215.4	186.8	272.7
Free operating cash flow	(115.4)	(108.1)	(27.2)	76.8	(60.5)
Dividends paid	33.1	25.0	25.2	116.4	46.2
Cash and short-term investments	154.3	330.2	211.4	340.5	216.0
Debt	1,711.7	1,583.0	1,344.3	1,311.4	1,338.6
Equity	1,055.8	1,018.6	987.7	997.2	915.1
Debt and equity	2,767.5	2,601.6	2,332.0	2,308.6	2,253.7
Adjusted ratios					
FFO interest coverage (x)	3.5	3.6	3.3	3.4	3.4
FFO/debt (%)	14.8	16.0	16.3	17.5	17.1
Debt/EBITDA (x)	5.1	4.8	4.5	4.4	4.1
Debt/debt and equity (%)	61.9	60.8	57.6	56.8	59.4
Common dividend payout ratio (unadjusted; %)	34.5	37.8	58.8	251.5	78.8

Table 3

Reconciliation Of Toronto Hydro Corp. Reported Amounts With Standard & Poor's Adjusted Amounts (Mil. C$)

	--Fiscal year ended Dec. 31, 2011--									
Toronto Hydro Corp. reported amounts	**Debt**	**Shareholders' equity**	**Revenues**	**EBITDA**	**Operating income**	**Interest expense**	**Cash flow from operations**	**Cash flow from operations**	**Dividends paid**	**Capital expenditures**
Reported	1,465.4	1,102.2	2,809.3	327.2	176.2	75.3	310.3	310.3	33.1	384.3
Standard & Poor's adjustments										
Operating leases	67.9	N/A	N/A	2.9	2.9	2.9	15.5	15.5	N/A	51.7
Postretirement benefit obligations	175.3	(46.5)	N/A	6.5	6.5	11.5	(5.7)	(5.7)	N/A	N/A
Capitalized interest	N/A	N/A	N/A	N/A	N/A	3.8	(3.8)	(3.8)	N/A	(3.8)

Table 3

Reconciliation Of Toronto Hydro Corp. Reported Amounts With Standard & Poor's Adjusted Amounts (Mil. C$) (cont.)										
Asset retirement obligations	3.2	N/A	N/A	0.2	0.2	0.2	0.3	0.3	N/A	N/A
Reclassification of working-capital cash flow changes	N/A	N/A	N/A	N/A	N/A	N/A	N/A	(64.1)	N/A	N/A
Total adjustments	246.3	(46.5)	0.0	9.5	9.5	18.4	6.3	(57.8)	0.0	47.9
Standard & Poor's adjusted amounts	**Debt**	**Equity**	**Revenues**	**EBITDA**	**EBIT**	**Interest expense**	**Cash flow from operations**	**Funds from operations**	**Dividends paid**	**Capital expenditures**
Adjusted	1,711.7	1,055.8	2,809.3	336.8	185.7	93.7	316.7	252.6	33.1	432.1

N/A--Not applicable.

Related Criteria And Research

- Methodology: Business Risk/Financial Risk Matrix Expanded, Sept. 18, 2012
- Implications Of The Canadian Regulated Utility Sector's Mixed Bag Of Accounting Standards, Aug. 31, 2012
- Methodology And Assumptions: Liquidity Descriptors For Global Corporate Issuers, Sept. 28, 2011
- Rating Government-Related Entities: Methodology And Assumptions, Dec. 9, 2010
- Key Credit Factors: Business And Financial Risks In The Investor-Owned Utilities Industry, Nov. 26, 2008
- 2008 Corporate Criteria: Analytical Methodology, April 15, 2008

Ratings Detail (As Of September 20, 2012)	
Toronto Hydro Corp.	
Corporate Credit Rating	A/Stable/--
Senior Unsecured	A
Corporate Credit Ratings History	
03-Jun-2008	A/Stable/--
26-Mar-2007	A-/Positive/--
20-Apr-2004	A-/Stable/--
Business Risk Profile	Excellent
Financial Risk Profile	Significant

*Unless otherwise noted, all ratings in this report are global scale ratings. Standard & Poor's credit ratings on the global scale are comparable across countries. Standard & Poor's credit ratings on a national scale are relative to obligors or obligations within that specific country.

RESPONSES TO SCHOOL ENERGY COALITION INTERROGATORIES ON ISSUE 1.3

INTERROGATORY 2:

Reference(s): none provided

Please provide Fixed Asset Continuity Schedules for 2010 and 2011.

RESPONSE:

Please see the attached Appendix A.

Fixed Asset Continuity Schedule

Table 1: Historical 2010

				Cost				**Accumulated Depreciation**				
CCA Class	OEB	Description	Depreciation Rate	Opening Balance	Additions	Disposals and Transfers	Closing Balance	Opening Balance	Additions	Disposals and Transfers	Closing Balance	Net Book Value
N/A	1805	Land	NA	2.1	5.6	(0.0)	7.7	-	-	-	-	7.7
CEC	1806	Land Rights	2.0%	-	-	-	-	-	-	-	-	-
47	1808	Buildings	2.0%	43.8	2.1	(0.0)	45.9	16.6	0.9	(0.0)	17.4	28.4
13	1810	Leasehold Improvements	10.0%	-	-	-	-	-	-	-	-	-
47	1815	Transformer Station Equipment >50 kV	2.5%	11.9	-	-	11.9	4.1	0.3	-	4.5	7.4
47	1820	Substation Equipment	3.3%	201.8	10.3	(5.9)	206.2	83.6	6.2	(0.3)	89.6	116.6
47	1825	Storage Battery Equipment	NA	-	-	-	-	-	-	-	-	-
47	1830	Poles, Towers & Fixtures	4.0%	337.0	13.1	-	350.1	158.3	12.7	-	171.0	179.1
47	1835	OH Conductors & Devices	4.0%	350.5	27.6	-	378.1	227.4	13.2	-	240.6	137.5
47	1840	UG Conduit	4.0%	1,101.1	77.7	-	1,178.8	547.5	41.3	-	588.7	590.1
47	1845	UG Conductors & Devices	4.0%	680.6	41.9	-	722.4	351.4	26.3	-	377.7	344.7
47	1850	Line Transformers	4.0%	639.0	43.7	-	682.6	333.5	23.4	-	356.9	325.8
47	1855	Services (OH & UG)	4.0%	68.9	3.7	-	72.6	10.2	2.8	-	13.0	59.6
47	1860	Meters	4.0%	133.0	(5.8)	5.9	133.1	93.3	4.0	0.3	97.6	35.5
47	1861	Smart Meters	6.7%	60.2	17.8	(17.8)	60.2	12.0	4.0	-	16.0	44.2
47	1861	Suite Meters	6.7%	2.7	7.8	-	10.6	0.2	0.3	-	0.5	10.1
47	1861	Smart Meters/Communication Systems	6.7%	-	-	-	-	-	-	-	-	-
N/A	1905	Land	NA	1.9	-	(0.0)	1.9	-	-	-	-	1.9
CEC	1906	Land Rights	2.0%	-	-	-	-	-	-	-	-	-
47	1908	Buildings & Fixtures	2.0%	102.3	4.1	(0.7)	105.7	36.9	2.0	(0.7)	38.2	67.5
13	1910	Leasehold Improvements	20.0%	19.0	0.4	-	19.5	9.4	3.4	-	12.8	6.7
8	1915	Office Furniture & Equipment 10yr	10.0%	11.1	5.3	-	16.4	6.0	1.0	-	7.0	9.4
8	1915	Office Furniture & Equipment 5yr	10.0%	-	-	-	-	-	-	-	-	-
10	1920	Computer - Hardware	25.0%	33.1	7.6	(0.1)	40.6	27.4	3.8	-	31.2	9.4
45	1921	Computer - Hardware post Mar 22/04	25.0%	-	-	-	-	-	-	-	-	-
45.1	1921	Computer - Hardware post Mar 19/07	25.0%	-	-	-	-	-	-	-	-	-
12	1925	Computer Software	20.0%	145.1	29.3	(1.6)	172.7	113.2	16.1	-	129.3	43.4
10	1930	Transportation Equipment - Automobiles	25.0%	1.3	0.1	(0.2)	1.2	1.0	0.2	(0.3)	0.9	0.3
10	1930	Transportation Equipment - Trucks <3 tonnes	20.0%	10.2	1.6	(0.1)	11.6	7.2	1.1	(0.1)	8.1	3.5
10	1930	Transportation Equipment - Trucks >3 tonnes	12.5%	53.2	9.1	(4.2)	58.2	32.2	4.2	(4.2)	32.2	26.0
10	1930	Transportation Equipment - Work and Service	12.5%	2.5	0.3	-	2.8	1.9	0.1	-	2.0	0.8
8	1935	Stores Equipment	10.0%	5.5	-	-	5.5	5.5	0.0	-	5.5	0.0
8	1940	Tools, Shop & Garage Equipment	10.0%	32.5	4.3	-	36.7	23.8	1.6	-	25.4	11.3
8	1945	Measurement & Testing Equipment	10.0%	4.7	0.2	-	4.9	4.2	0.1	-	4.3	0.6
8	1950	Power operated Equipment	12.5%	-	-	-	-	-	-	-	-	-
8	1955	Communications Equipment	20.0%	23.9	3.0	-	26.8	19.0	2.0	-	21.0	5.8
8	1960	Miscellaneous Equipment	10.0%	0.1	0.2	(0.1)	0.2	0.1	0.0	(0.1)	0.0	0.2
47	1965	Water Heater Rental Units	10.0%	-	-	-	-	-	-	-	-	-
47	1970	Load Management Controls	10.0%	15.2	-	-	15.2	7.5	1.1	-	8.6	6.6
47	1975	Load Management Controls Utility Premises	10.0%	0.6	-	-	0.6	0.6	-	-	0.6	-
47	1980	System Supervisor Equipment	6.7%	52.5	3.9	-	56.4	33.9	2.3	-	36.2	20.3
47	1985	Miscellaneous Fixed Assets	10.0%	0.0	-	(0.0)	-	0.0	-	(0.0)	-	-
47	1996	Hydro One S/S Contribution		-	-	-	-	-	-	-	-	-
47	1995	Contributions & Grants	4.0%	(242.7)	(15.4)	-	(258.1)	(43.4)	(9.9)	-	(53.2)	(204.9)
10	2005	Property Under Capital Lease	25%	0.8	0.4	(0.3)	0.9	0.4	0.2	(0.2)	0.4	0.5
		Total		3,905.4	299.5	(25.2)	4,179.7	2,124.6	165.0	(5.7)	2,283.9	1,895.8

Less: Fully Allocated Depreciation	
Transportation	(2.1)
Net Depreciation	162.9

Note: Components may not add up exactly to Total due to rounding.

Note: Depreciation for "2005 - Property under Capital Lease" is now shown separately instead of included in "1930 - transportation Equipment - Automobiles"

Fixed Asset Continuity Schedule

Table 2: Historical 2011

			Cost					**Accumulated Depreciation**				
CCA Class	OEB	Description	Depreciation Rate	Opening Balance	Additions	Disposals and Transfers	Closing Balance	Opening Balance	Additions	Disposals and Transfers	Closing Balance	Net Book Value
N/A	1805	Land	0.02	7.7	(0.0)	(0.1)	7.6	-	-	-	-	7.6
CEC	1806	Land Rights	2.0%	-	-	-	-	-	-	-	-	-
47	1808	Buildings	10.0%	45.9	2.5	(3.8)	44.6	17.4	1.6	(1.2)	17.8	26.7
13	1810	Leasehold Improvements	2.5%	-	-	-	-	-	-	-	-	-
47	1815	Transformer Station Equipment >50 kV	3.3%	11.9	12.6	-	24.6	4.5	1.3	-	5.8	18.8
47	1820	Substation Equipment	NA	206.2	23.2	(0.0)	229.4	89.6	7.2	(0.0)	96.9	132.5
47	1825	Storage Battery Equipment	4.00%	-	-	-	-	-	-	-	-	-
47	1830	Poles, Towers & Fixtures	4.0%	350.1	29.0	-	379.1	171.0	5.8	-	176.8	202.2
47	1835	OH Conductors & Devices	4.0%	378.1	34.9	-	413.0	240.6	4.3	-	244.9	168.0
47	1840	UG Conduit	4.0%	1,178.8	134.1	-	1,312.9	588.7	31.9	-	620.7	692.2
47	1845	UG Conductors & Devices	4.0%	722.4	66.2	-	788.6	377.7	13.8	-	391.6	397.1
47	1850	Line Transformers	4.0%	682.6	49.0	-	731.7	356.9	21.4	-	378.3	353.4
47	1855	Services (OH & UG)	4.0%	72.6	2.9	-	75.5	13.0	1.4	-	14.5	61.0
47	1860	Meters	6.7%	133.1	4.7	0.0	137.8	97.6	4.0	0.0	101.6	36.2
47	1861	Smart Meters	6.7%	60.2	10.0	-	70.2	16.0	4.4	-	20.4	49.8
47	1861	Suite Meters	6.7%	10.6	2.9	-	13.4	0.5	0.5	-	1.0	12.4
47	1861	Smart Meters/Communication Systems	NA	-	-	-	-	-	-	-	-	-
N/A	1905	Land	0.02	1.9	7.3	-	9.2	-	-	-	-	9.2
CEC	1906	Land Rights	2.0%	-	-	-	-	-	-	-	-	-
47	1908	Buildings & Fixtures	20.0%	105.7	4.6	0.0	110.3	38.2	6.4	0.0	44.6	65.8
13	1910	Leasehold Improvements	10.0%	19.5	0.3	-	19.8	12.8	6.0	-	18.8	1.0
8	1915	Office Furniture & Equipment 10yr	10.0%	16.4	4.1	-	20.5	7.0	1.5	-	8.5	12.0
8	1915	Office Furniture & Equipment 5yr	25.0%	-	-	-	-	-	-	-	-	-
10	1920	Computer - Hardware	25.0%	40.6	4.0	-	44.6	31.2	4.4	-	35.6	9.0
45	1921	Computer - Hardware post Mar 22/04	25.0%	-	-	-	-	-	-	-	-	-
45.1	1921	Computer - Hardware post Mar 19/07	20.0%	-	-	-	-	-	-	-	-	-
12	1925	Computer Software	25.0%	172.7	53.1	(3.2)	222.6	129.3	24.9	-	154.2	68.4
10	1930	Transportation Equipment - Automobiles	20.0%	1.2	0.3	(0.2)	1.2	0.9	0.2	(0.3)	0.8	0.3
10	1930	Transportation Equipment - Trucks <3 tonnes	12.5%	11.6	3.3	(3.0)	11.9	8.1	1.4	(3.0)	6.6	5.3
10	1930	Transportation Equipment - Trucks >3 tonnes	12.5%	58.2	7.5	(3.5)	62.2	32.2	5.0	(3.5)	33.8	28.4
10	1930	Transportation Equipment - Work and Service	10.0%	2.8	0.2	(0.2)	2.7	2.0	0.2	(0.2)	2.0	0.8
8	1935	Stores Equipment	10.0%	5.5	-	-	5.5	5.5	0.0	-	5.5	0.0
8	1940	Tools, Shop & Garage Equipment	10.0%	36.7	2.6	(0.2)	39.2	25.4	1.9	-	27.4	11.8
8	1945	Measurement & Testing Equipment	12.5%	4.9	13.6	-	18.4	4.3	1.1	-	5.4	13.0
8	1950	Power operated Equipment	20.0%	-	-	-	-	-	-	-	-	-
8	1955	Communications Equipment	10.0%	26.8	1.4	3.4	31.5	21.0	2.9	-	23.9	7.6
8	1960	Miscellaneous Equipment	10.0%	0.2	0.2	-	0.4	0.0	0.0	-	0.0	0.3
47	1965	Water Heater Rental Units	10.0%	-	-	-	-	-	-	-	-	-
47	1970	Load Management Controls	10.0%	15.2	(0.3)	-	14.8	8.6	1.0	-	9.7	5.2
47	1975	Load Management Controls Utility Premises	6.7%	0.6	-	-	0.6	0.6	-	-	0.6	-
47	1980	System Supervisor Equipment	10.0%	56.4	1.2	-	57.6	36.2	1.8	-	37.9	19.6
47	1985	Miscellaneous Fixed Assets		-	-	-	-	-	-	-	-	-
47	1996	Hydro One S/S Contribution	4.00%	-	-	-	-	-	-	-	-	-
47	1995	Contributions & Grants	25.0%	(258.1)	(36.4)	-	(294.5)	(53.2)	(8.2)	-	(61.4)	(233.0)
10	2005	Property Under Capital Lease		0.9	0.3	(0.3)	0.9	0.4	0.2	(0.2)	0.3	0.6
		Total		4,179.7	439.1	(11.1)	4,607.8	2,283.9	148.6	(8.3)	2,424.2	2,183.5

Less: Fully Allocated Depreciation	
Transportation	(2.2)
Net Depreciation	146.4

Note: Components may not add up exactly to Total due to rounding.

Note: Depreciation for "2005 - Property under Capital Lease" is now shown separately instead of included in "1930 - transportation Equipment - Automobiles"

RESPONSES TO SCHOOL ENERGY COALITION INTERROGATORIES ON ISSUE 1.3

INTERROGATORY 3:

Reference(s): none provided

Please provide a variance analysis between the closing rate base derived from the Settlement Agreement in EB-2010-0142 and 2011 actuals.

RESPONSE:

The 2011 closing balance of net fixed assets underpinning the OEB-approved rate base in the EB-2010-0142 Settlement Agreement is $2,001.5 million. The actual 2011 closing balance of net fixed assets is $2,039.7 million as shown in the table below. The difference between these two balances of $38.2 million reflects the higher energization levels due to higher actual 2011 spending. Actual 2011 spending was $66.7 million higher than the approved spending of $378.8M.

RESPONSES TO SCHOOL ENERGY COALITION INTERROGATORIES ON ISSUE 1.3

Gross Fixed Assets - 2011 Actuals	Opening Balance	Additions	Disposals	Ending Balance
Land_and_Buildings	55.4	9.8	- 3.9	61.3
TS_Primary Above 50	11.9	12.6	-	24.6
Distribution Stn Equip	206.2	23.2	- 0.0	229.4
Poles_Wires	2,629.4	264.2	-	2,893.6
Line_Transformers	682.6	49.0	-	731.7
Services_and_Meters	276.4	20.5	0.0	296.9
Asset - General Plant	125.1	4.9	0.0	130.1
Equipmnt	164.2	33.1	- 3.8	193.6
IT_Assets	213.3	57.1	- 3.2	267.2
Other_Distribution Assets	73.0	1.1	- 0.3	73.8
Contributions and Grants - Credits	- 258.1	- 36.4	-	- 294.5
Non_Distribution Asset	-	-	-	-
Grand Total	4,179.7	439.1	- 11.1	4,607.8
Average				4,393.7

Accumulated Depreciation - 2011 Actuals	Opening Balance	Additions	Disposals	Ending Balance
Land_and_Buildings	17.4	1.6	- 1.2	17.8
TS_Primary Above 50	4.5	1.3	-	5.8
Distribution Stn Equip	89.6	7.2	- 0.0	96.9
Poles_Wires	1,378.1	56.0	-	1,434.0
Line_Transformers	356.9	21.4	-	378.3
Services_and_Meters	127.1	10.4	0.0	137.5
Asset - General Plant	50.9	12.4	0.0	63.3
Equipmnt	106.5	14.3	- 6.9	113.8
IT_Assets	160.5	29.3	-	189.8
Other_Distribution Assets	45.7	3.0	- 0.2	48.4
Contributions and Grants - Credits	- 53.2	- 8.2	-	- 61.4
Non_Distribution Asset	-	-	-	-
Grand Total	2,283.9	148.6	- 8.3	2,424.2
Average				2,354.1
Average NFA				2,039.7

RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORIES ON ISSUE 1.3

INTERROGATORY 7:

Reference(s): **Tab 2, pages 4-6**

a) Is THESL's proposal for a rate rider to recognize the 2011 year-end rate base separate (i.e. severable) from its ICM proposal?

RESPONSE:

a) Yes.

b) Is it THESL's contention that the Board was not aware of the ½ year rule impact on rate base issue when it approved the 3rd Generation IRM? If yes, what is the basis for this view?

RESPONSE:

b) THESL cannot comment on what the OEB was, or was not, aware of in this regard.

c) Please confirm that, under a price-capped based IRM approach (as adopted by the OEB), distribution rates for the test year are not based on the test year's costs as is the case under a cost of service approach.

RESPONSE:

c) THESL confirms its understanding that under IRM, rates for the years between rebasings are determined by adjusting the cost-based rates determined in the prior rebasing year by the annual PCI factor. Rates during the IRM period are derivative from cost-based rates and rates return to being directly cost based upon rebasing, usually every fourth year.

RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORIES ON ISSUE 1.3

d) If IRM rates are not cost-based, please explain the basis for THESL's contention that it is experiencing "an effective disallowance of $120 M of approved rate base".

RESPONSE:

d) Please refer to pages 4 to 6 of the revised Manager's Summary, where THESL specifically explains the basis of its statement.

e) Please explain why it is appropriate to select and adjust certain specific "contributors" to what would be the calculation of a cost of service-based revenue requirement determination in 2012-2014 (e.g., 2011 year-end rate base) while ignoring others.

RESPONSE:

e) THESL understands that the IRM framework adjusts cost-based rates determined at rebasing by a series of annual PCI factors which the OEB has determined serve as an appropriate proxy during the IRM years for what would otherwise be determined by direct rebasing. THESL does not challenge in this proceeding the use of the PCI factors as proxy determinants of the evolution of rates. However, due to the presence of a substantial amount of CEEDs for THESL during the rebasing year, a material portion of OEB-approved capital expenditures is systematically excluded from the PCI adjustment. Therefore it is incorrect to suggest that THESL is being 'selective' in adjusting some factors and not others; THESL is simply asserting that the PCI adjustment properly applies to the entire OEB-approved capital base that is being used in providing service to customers.

RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORIES ON ISSUE 1.3

INTERROGATORY 8:

Reference(s): Tab 2, Appendix 1, page 1

a) Please confirm that, based on the 1/2 year rule, $189.4 M of the $378.8 M in approved capital spending for 2011 would have been included in the approved rate base for 2011 and in the derivation of the 2011 rates. If not, how much of the $378.8 M was included in the approved rate base for 2011?

RESPONSE:

a) The half year rule provides that half of capital spending in a given year is one of the determinants of ratebase for that year. Other determinants include depreciation and changes in the CWIP balance. Apart from changes in the CWIP balance, half of depreciation in the year must be deducted from (half of) the capital spending to arrive at average ratebase, so in this case, average ratebase would be given by the expression:

(OPENING BALANCE + CAPEX/2 – DEPRECIATION/2) or
(OPENING BALANCE + 378.8/2 – 138.8/2)
= OPENING BALANCE + 189.4 – 69.4
= OPENING BALANCE + 120

b) How is this accounted for in the calculations set out in Appendix 1?

RESPONSE:

b) Please refer to THESL's response to a) above.

RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORIES ON ISSUE 1.3

INTERROGATORY 9:

Reference(s): **Tab 2, page 5**

a) How much of the actual capital spending for 2011 ($445.5 M) was related to facilities that were in-service and used & useful as of 2011 year end?

RESPONSE:

a) The total THESL actual capital spending for 2011 that was energized (used & useful) as at December 31, 2011 was $270M.

RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORIES ON ISSUE 1.3

INTERROGATORY 10:

Reference(s): **Tab 2. Appendix 1**

a) Please confirm that the allocation of the $12.9 M for 2012 to customer classes is based on each class' revenue contribution to the approved base distribution revenue requirement using 2011 rates and loads.

RESPONSE:

a) The allocation of the $12.9M for 2012 to customer classes is based on each class' revenue contribution to the approved base distribution revenue requirement using 2011 OEB-approved rates and loads.

b) If this is the case, please explain why the resulting rider for the Residential class is more than twice that for the Competitive Sector Multi-Unit Residential class ($0.44 vs. $0.17) when the monthly service charge is only 7.3% higher ($18.25 vs. $17).

RESPONSE:

b) The values for percentage of revenue used in the tables filed are incorrect. Please see the response to EP interrogatory 7a (Tab 6C, Schedule 7-7, part a).

c) Please provide the working excel spreadsheet that derives the fixed and variable revenues for each rate class based on approved rates and the resulting percentages set out in columns A-C of the tables on pages 2-4.

RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORIES ON ISSUE 1.3

RESPONSE:

c) The derivation of the fixed and variable revenues is contained in Tab 4, Schedule E1.1, page 8. The attached Appendix A recreates this sheet from the ICM model in Excel format.

THESL will provide revised version of Tab 4, Schedule E1.1, page 8 in its forthcoming evidentiary update.

Rate Class	Fixed Metric	Vol Metric	Current Base Service Charge	Current Base Distribution Volumetric Rate kWh	Current Base Distribution Volumetric Rate kW	Re-based Billed Customers or Connections	Re-based Billed kWh	Re-based Billed kW	Current Base Service Charge Revenue	Current Base Distribution Volumetric Rate kWh Revenue	Current Base Distribution Volumetric Rate kW Revenue	Total Current Base Revenue	Service Charge % Total Revenue	Distribution Volumetric Rate % Total Revenue	Distribution Volumetric Rate % Total Revenue	Total % Revenue
			A	B	C	D	E	F	G = A * D *12	H = B * E	I = C * F	J = G + H + I	L = G / $K	M = H / $K	N = I / $K	O = J / $K
Residential	Customer	kWh	18.25	0.01507		598,508	4,886,977,489	-	131,073,252	73,646,751	-	204,720,003	24.82%	13.95%	0.00%	38.77%
Residential Urban	Customer	kWh	17	0.02565		24,898	99,791,184	-	5,079,192	2,559,644	-	7,638,836	0.96%	0.48%	0.00%	1.45%
General Service Less Than 50 kW	Customer	kWh	24.3	0.02247		65,792	2,139,318,076	-	19,184,993	48,070,477	-	67,255,470	3.63%	9.10%	0.00%	12.74%
General Service 50 to 999 kW	Customer	kW	35.56		5.5956	13,067	10,116,374,153	26,935,191	5,575,758	-	150,718,556	156,294,314	1.06%	0.00%	28.54%	29.60%
General Service 1,000 to 4,999 kW	Customer	kW	686.46		4.4497	514	4,626,928,262	10,587,119	4,234,085	-	47,109,505	51,343,590	0.80%	0.00%	8.92%	9.72%
Large Use	Customer	kW	3009.11		4.7406	47	2,376,778,323	4,993,733	1,697,138	-	23,673,292	25,370,430	0.32%	0.00%	4.48%	4.80%
Street Lighting	Connectior	kW	1.3		28.7248	162,777	110,165,016	322,023	2,539,322	-	9,250,042	11,789,364	0.48%	0.00%	1.75%	2.23%
Unmetered Scattered Load	Connectior	kWh	4.84	0.0607		1,130	56,231,585	-	65,611	3,413,257	-	3,478,868	0.01%	0.65%	0.00%	0.66%
Unmetered Scattered Load	Connectior	kWh	0.49			21,729	-	-	127,767	-	-	127,767	0.02%	0.00%	0.00%	0.02%
									169,577,117	127,690,129	230,751,395	528,018,642	32.12%	24.18%	43.70%	100.00%

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES ON ISSUE 1.4

INTERROGATORY 12:

Reference(s): **T2/p.6**

It is stated that:

> "In this application THESL proposes a period of three years overall, with each distinct year (2012 through 2014) being severable, and with each year having distinct distribution rates."

Please state whether given the severability referenced above the Board could choose to approve only the first year of THESL's proposal and, if so, what the implications would be. If not, please explain, why not.

RESPONSE:

Yes, as it is within the jurisdiction of the OEB to approve all, part, or none of any relief sought in an application, the OEB could approve just the first year of the three year period of the application.

As to the implications of the OEB approving only the first year of THESL's application, please see THESL's response to OEB Staff interrogatory 10 (Tab 6A, Schedule 1-10). While a one year approval would somewhat mitigate these circumstances for THESL, years two and three of THESL's capital needs as proposed in this application would remain unaddressed.

THESL is unable to further speculate on the specific implications of an approval limited to 2012, without THESL knowing the OEB's specific findings.

RESPONSES TO ASSOCIATION OF MAJOR POWER CONSUMERS IN ONTARIO INTERROGATORIES ON ISSUE 1.4

INTERROGATORY 3:

Reference(s): Tab 2

a) Please describe THESL's plan to set rates in 2013 and 2014 if the Board does not approve its proposed IRM/ ICM applications at this time for 2013 and 2014?

RESPONSE:

a) Please see THESL's responses to OEB Staff interrogatory 10 and CCC interrogatory 11 (Tab 6A, Schedule 1-10 and Tab 6B, Schedule 6-11, respectively).

b) Please confirm THESL's next Cost of Service application is planned for 2015.

RESPONSE:

b) Confirmed.

RESPONSES TO CONSUMERS COUNCIL OF CANADA INTERROGATORIES ON ISSUE 1.4

INTERROGATORY 16:

Reference(s): Tab 2/p. 14

How does the Board's recent announcement regarding the Renewed Regulatory Framework for Electricity impact THESL's application? The evidence states that, "While the implementation of the new framework remains to be determined, it is THESL's view that nothing in this application would constrain the adoption of a new framework for THESL, even prior to 2015". Does this imply that if the Board approved 2014 rates, and a final rate order arising from this application, THESL would be free to re-apply for rates for 2014 under the new framework?

RESPONSE:

Please see response to SEC interrogatory 4 (Tab 6D, Schedule 10-4).

The OEB will determine what options are available to utilities under the RRFE. THESL must await the decision in this proceeding, as well as the options under RRFE and the timing of their availability, before determining its next steps.

RESPONSES TO SCHOOL ENERGY COALITION INTERROGATORIES ON ISSUE 1.4

INTERROGATORY 4:

Reference(s): none provided

How has the Applicant's plans for the filing of any applications for rates for 2013 and 2014 changed as a result of the pending release of the report on the Board's *Renewed Regulatory Framework for Electricity*? If so, does the Applicant believe it requires a change to this application?

RESPONSE:

At this time, THESL's plans for rate applications for 2013 and 2014 have not changed as a result of information currently available to THESL with respect to the RRFE.

RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORIES ON ISSUE 1.4

INTERROGATORY 11:

Reference(s): Tab 1, page 6, lines 8-11

a) Apart from ICM rate adders for 2013 and 2014 (as set out in paragraph 14), specifically what is THESL requesting the Board approval for (at this time) regarding the distribution rates to be effective May 1, 2013 and May 1, 2014?

RESPONSE:

a) THESL anticipates that the OEB will treat base distribution rates separately from the ICM rate adders. With respect to base distribution rates, THESL anticipates that the OEB will direct that the base rates determined for 2012 be adjusted by the then current PCI factors for 2013 and 2014, on the basis of THESL filing the appropriate applications for those adjustments. THESL does not propose that the OEB pre-determine those PCI adjustments to base rates at this time.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES ON ISSUE 2.1

INTERROGATORY 15:

Reference(s): **T2/p. 23, Table 3 and EB-2011-0144 Exh S1/T1/S1**

The first reference shows that for 2012 THESL's EB-2011-0144 rebasing application had total capital requests of $590.0 million in contrast to the $448.7 million of capital requests that THESL is making in the current application.

The second reference is to Undertaking No. J2.1 from the EB-2011-0144 proceeding in which THESL was asked to provide a full list of projects that would be eligible for the incremental capital module and their dollar values. THESL responded that for 2012 a total of $86.6 million of projects consisting of the Bremner Station and HONI Contributions would be eligible.

Please explain why THESL now believes that a much greater number of its projects would be eligible for the incremental capital module.

RESPONSE:

At the time of providing the response to Undertaking J2.1, THESL responded according to the best knowledge and belief it had at the time with a list of projects which THESL felt would certainly qualify for ICM treatment. Since then THESL's thinking has evolved.

It appears to THESL that the ICM itself has evolved. First, the criteria which at one time may have been considered rigid and inflexible have proven to be more analogous to factors than hard and fast rules. The ICM has been shown to be responsive to a variety of circumstances.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES ON ISSUE 2.1

Second, the fundamental rationale for the ICM has remained constant – it is intended to provide approval for capital spending, which can be shown to be non-discretionary, prudently executed and incremental to existing rate support. In other words, at its core, it is intended to provide funding for needed projects that have no other funding.

Given the outcome of THESL's EB-2011-0144 application, together with the continuing urgent need for capital renewal across THESL's distribution system, THESL had no alternative but to seek funding under ICM criteria for projects it considers to be essential to maintain system reliability and safety for both employees and the public.

As part of the process of constructing the present application, THESL sought to eliminate projects that had been proposed in EB-2011-0144, which, while necessary, have been determined not to meet the standard of urgency and priority that characterize the work included in this ICM application. THESL continues to believe that the work left out of this ICM application is nevertheless necessary and prudent and should still be undertaken by the utility over the medium to long term.

As a result, THESL has presented in this application a portfolio of projects which it believes qualify for ICM treatment under the ICM factors as discussed in the Manager's Summary at pages 14-21.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES ON ISSUE 2.1

INTERROGATORY 16:

Reference(s): T2/p.6 and T2/pp. 23-24

In the first reference, it is stated when discussing the capital projects that THESL is proposing for approval in the current application that:

> "The projects and annual amount of ICM funding sought in THESL's application represent the level of capital funding that THESL requires in order to conduct a capital program that is expected to maintain the current levels of safety and reliability of its distribution system in a predictable and cost-effective manner."

In the second reference, which is THESL's discussion of the comparison between its cost of service and IRM/ICM applications and the differences between the larger capital program for which approval was sought in that application and the smaller one in the present application, THESL states that:

> "Projects of this kind were proposed by THESL in the EB-2011-0144 proceeding. THESL believes that the projects proposed there were prudent, necessary for the long term management and sustainment of the distribution system, and in the public interest."

Please reconcile these two statements.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES ON ISSUE 2.1

RESPONSE:

THESL views these two statements as consistent. These two statements refer to two different work proposals put forward in fundamentally different regulatory contexts.

The first addresses the projects proposed in this IRM/ICM application. It reflects the view of Operational and Asset Management Staffs that execution of the work included in this application is critical to the maintenance of an appropriately safe and reliable system for THESL's customers and its employees. THESL notes that over short intervals, reliability statistics can fluctuate according to short term influences such as the severity of weather and changes in the amount of work being done on the system. It is also THESL's view that the current menu of reliability statistical models is a poor substitute for the considered opinion of THESL's expert engineering resources, the opinion of external experts, and better, still to be developed more meaningful statistical models.

The second statement refers to projects contained in the 2012 cost of service application as being necessary to maintain the health of the THESL system. The paragraph that preceded the second statement is as follows:

> "THESL does not plan to execute projects such as Paper Insulated Lead Covered Cable Replacement, Asbestos Insulated Lead Covered Cable Replacement, Stations Infrastructure, Nomenclature, Grounding Compliance, Electric Vehicles and Modernization Initiatives in the next three years. In addition, for continuing project areas such as underground infrastructure, THESL now proposes further reductions in capital spending for the purposes of the submitted ICM projects relative to previous proposals."

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That paragraph enumerated some of the projects that appeared in the EB-2011-0144 application but were removed for purposes of the ICM application. The second statement refers to those projects, and THESL stands by its statement.

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INTERROGATORY 17:

Reference(s): **T2/pp. 14-15, T4/Sch A/App 1, T2/p. 7 and *Chapter 3 of the Filing Requirements For Electricity Transmission and Distribution Applications*, p 10**

In the first reference, THESL states that it "has carefully reviewed the ICM Material and has sought to address and meet the Board's criteria for consideration and acceptability of projects."

The second reference entitled "Summary of Capital Program" shows that THESL has defined for the purposes of this application, three annual ICM 'projects,' one each for the years 2012, 2013 and 2014 respectively.

In the third reference, THESL states that:

> "To this end, THESL files with this application a separate standard ICM model and separate projects for each of the three years. As discussed in greater detail below, the specific projects set out in the application generally span the whole three year period and are generally constituted of individual jobs. While for each year, THESL proposes a slate of jobs comprising each project, the structure of THESL's capital plan is such that the character of the jobs and the projects remains constant over the aggregate three-year period."

The final reference which is the Board's IRM Filing Requirements related to ICM modules appears to take the view that a capital project is an individual project e.g. the requirement that applicants seeking an ICM approval provide "Calculation of the revenue

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requirement associated with each proposed incremental non-discretionary capital project."

a) Please explain why THESL believes that the portfolio approach to capital projects which it is using in this application is appropriate and consistent with Board's Filing Requirements

RESPONSE:

a) THESL uses the term "portfolio" in its evidence to describe the collection of its entire application: ten discrete projects spread throughout three years, with 22 segments and hundreds of jobs. The remainder of this answer explains why THESL has organized its application into projects/segments/jobs, and how this method of proceeding is consistent with the OEB's filing requirements.

As a result of the scope and magnitude of THESL's ICM request, it sought to organize hundreds of individual "jobs" into coherent categories of work that would be familiar to the OEB and intervenors – these are the 21 "segments". From there, THESL sought to further organize its application into a smaller number of categories to assist the OEB and intervenors in being able to navigate and digest a comparatively large ICM application – these are the ten "projects".

Generally, THESL proceeded on the basis that projects should be defined on the basis of characteristics that unify the work. These characteristics could include attributes such as asset category, electrical function, and others that go to the cost drivers of the projects, such as the skills and equipment needed to complete the project (which can vary significantly among projects). In THESL's view, these defining characteristics

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should serve to make different projects coherent within themselves and distinct as between projects.

THESL believes that it has proceeded in a way that is consistent with the filing requirements. Although the Filing Guidelines use the term 'project', that term is not defined or described in those Guidelines. In short, THESL believes that the application has been organized in a manner that is substantively consistent with the underlying rationale of the ICM, which is to enable funding for work that is found to be needed and which is otherwise unfunded.

Please also refer to the Revised Manager's Summary, pages 14-15.

b) Please provide a table illustrating the difference in revenue requirement impacts for the 2012 to 2017 period in the event that the 2012 proposed capital level of $448.74 million was approved under two different assumptions: (1) THESL's proposal that this amount be approved through the ICM mechanism and (2) the impacts that would have arisen had this amount been approved through a cost-of-service mechanism. Please include all necessary explanations.

RESPONSE:

b) The incremental Revenue Requirement associated with the 2012 Capex amount of $448.7M, under the Board's ICM standard methodology, is $26.8M, as calculated in Tab 4, Schedule E1.1, page 12. THESL has calculated rate riders which will collect this amount in each of 2012, 2013, and 2014. In 2015, at the time of rebasing, the capital amounts which have actually been spent and recorded in the ICM deferral accounts will be reconciled with the revenues received through the rate adders, and

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any variance will be returned to or collected from customers as a rate rider in 2015. This true-up is a crucial component of the ICM framework. It ensures that whatever flexibility may be needed throughout the execution of the work will not be at the risk of ratepayers or the shareholder. Work or the pace of work may shift from one period to another, according to the natural exigencies of the real world, but in all events the ratepayer is protected by the true-up, which will account for the execution of the work.

Had THESL applied for the 2012 capital amounts under a Cost of Service framework and under the assumption that THESL received approval for the entire capital program of $448.7M, base rates would be calculated to recover this amount in 2012. In the subsequent two years, under the assumption THESL continues to file cost of service applications, the amounts spent in 2012 (less depreciation) would form part of rate base in these subsequent years.

Under the assumption that the actual spending was equal to approved spending in each year until rebasing, in the 2015 rebasing year, ratebase would reflect the $448.7M spent in 2012, less depreciation.

Due to the true-up of actual spending under the ICM mechanism, the ratebase on rebasing in 2015 would be the same as the ratebase under Cost of Service under the assumption that actual spending equalled approved spending. As noted, under the ICM any variance will be returned or collected from customers through the true-up mechanism, leaving them fully protected. It is worth noting that under a Cost of Service application the capital budget, once approved, is embedded in rates, generally without any prospect of re-capture should the utility underspend. This proposal not

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only provides an extremely granular representation with respect to capital work, but offers a definitive true-up for the benefit of ratepayers and the shareholder. On the assumption that actual spending equals approved spending, the net financial impact would be identical under the COS and ICM models.

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INTERROGATORY 18:

Reference(s): **T2/p. 14 and *Chapter 3 of the Filing Requirements For Electricity Transmission and Distribution Applications*, p 8**

In the first reference, THESL states that it "has carefully reviewed the ICM Material and has sought to address and meet the Board's criteria for consideration and acceptability of projects."

In the second reference, it is stated that "A distributor applying for recovery of incremental capital should calculate the maximum allowable capital amount by taking the difference between the 2013 total non-discretionary capital expenditure and the materiality threshold." Please provide this calculation for each of the years 2012, 2013 and 2014.

RESPONSE:

The information requested can be found at Tab 4, Schedules E1.2, E2.2, and E3.3.

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INTERROGATORY 19:

Reference(s): **T2/pp. 16-17**

In its discussion of the "Need" criteria for the projects it is proposing, THESL states that "Generally, projects are essential and non-discretionary on the basis that they are required by one or more of the following:"

One of the listed criteria is described as "A material increase in cost (beyond the time value of money), if the project is necessary but undertaken at a later time." An example is cited of a project to install four ducts one at a time having a substantially larger cost than the current cost to install four ducts at one time.

It is concluded that: "In this light the project to install the ductwork for all four feeders at one time becomes non-discretionary because it would be imprudent to install the ductwork separately for each feeder."

Please describe the characteristics of a project that would not be considered non-discretionary under the outlined approach.

RESPONSE:

A project that does not exhibit similar economies of scale or scope would not be considered non-discretionary under the outlined approach. For example, if there are multiple feeders in different locations such that there were no savings from installing the duct work for them at the same time, the example cited above from the Manager's Summary would not support a conclusion that each feeder project was non-discretionary.

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THESL's basic point in this example is that THESL understands the OEB to be concerned with long term cost minimization such that an initially higher cost may be prudently incurred to yield a material savings overall. Simply put, THESL is seeking to make wise decisions about equipment replacement, not merely expedient decisions. In THESL's view, protection of the ratepayer includes protection from replacement decisions that are short-sighted and unreasonably limited or restricted.

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INTERROGATORY 20:

Reference(s): T2/p. 18

It is stated that:

> "For a number of projects for which THESL seeks ICM funding, need is supported by consideration of worker and/or public safety. For some projects, the current residual safety risk of certain equipment is a major driver for why the proposed project is needed."

a) Please state whether this criterion was quantified in THESL's determination of projects to be included in the ICM and if so, how. If not please explain how it was incorporated.

RESPONSE:

a) THESL has analyzed the claims that it has received for property damage and injury and incorporated this information on a probabilistic basis as part of the indirect costs used in THESL's quantified business case evaluation process. It has not attempted to quantify or incorporate the potential cost of severe injury or death.

b) Please state for which projects this consideration was a major driver.

RESPONSE:

b) Safety is a major driver for undertaking the following projects: PILC – Piece Outs and Leakers, Handwell Replacement, Box Construction, Rear Lot Construction, SMD-20 Switches, SCADA-Mate R1 Switches, Network Vaults & Roofs, Fibertop

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Network Units, and Automatic Transfer Switches & Reverse Power Breakers. It was also a material consideration in the Underground Infrastructure, Overhead Infrastructure, Stations Power Transformers, and Stations Circuit Breakers projects. The specific safety concerns for each project segment can be found in their respective write-ups within the application.

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INTERROGATORY 21:

Reference(s): T2/pp. 19-20

On these pages, prudence is defined as follows:

> "…the achievement of or approach to the lowest reasonable life cycle cost consistent with all other constraints, including for example safety of equipment, compliance with standards including accepted standards of good utility practice, public acceptability and the reliability and adequacy of the distribution system."

Please state how this definition was determined.

RESPONSE:

THESL's definition is THESL's understanding of the definition of prudence as contained in the OEB's filing guidelines, expanded to explain how THESL has sought to apply that definition. In THESL's view prudence requires wise decisions, not merely expedient decisions.

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INTERROGATORY 22:

Reference(s): **T2/p. 22**

It is stated that:

> "THESL also understands that the true-up process will account for the actual timing of jobs, and that a variance in job timing would not, by itself, cause any job to become ineligible for inclusion in the calculation of the actual revenue requirements associated with the ICM."

a) Please state the basis for this understanding.

RESPONSE:

a) THESL's understanding is based on Sections 2.2.6 and 2.2.7 of the OEB's IRM Filing Requirements dated June 22, 2011. Section 2.2.6 specifically provides that:

> "A distributor that receives rate relief through this module will be required to report to the Board annually on the actual amounts spent. At the time of the next rebasing, the distributor will file a calculation of the amounts to be incorporated in rate base. At that time the Board will make a determination on the treatment of any difference between forecast and actual capital spending during the IRM plan term. Any overspending or underspending will be reviewed at the time of rebasing."

The OEB generally indicates that at the time of rebasing it will determine the amounts to be included in ratebase prospectively and the treatment of any difference between forecast and actual capital spending. THESL understands on this basis that the OEB intends to follow the conventional approaches to the determination of allowable

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ratebase and the disposition of any variance between the imputed revenue requirement attributable to ICM projects and revenue actually derived through ICM rate adders. To the extent that the OEB intends to follow a different protocol or impose more specific requirements, THESL respectfully requests that the OEB articulate its direction to THESL by way of its decision in this proceeding.

b) Please state how THESL defines "a variance in job timing."

RESPONSE:

b) A 'variance in job timing' would arise if a particular job was proposed and approved for execution in, for example, 2013, but for a variety of practical reasons was advanced to 2012 or delayed to 2014.

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INTERROGATORY 4:

Reference(s): Tab 4, Schedule A, Appendix 1, page 1

a) Please identify the projects in Appendix 1 that were unanticipated in 2012, 2013 and 2014 in the context of THESL's long term capital plan.

RESPONSE:

a) Unanticipated capital work for 2012, 2013, and 2014 in the present ICM application includes any work that was not included in THESL's EB-2011-0144 application. For further information on specific segments, please refer to the response to VECC interrogatory 26b (Tab 6F, Schedule 11-26, part b).

b) Please discuss each capital segment in Appendix 1 in the context of the significant influence on the operation of the distributor.

RESPONSE:

b) THESL's evidence for each segment discusses how that segment affects the provision of distribution service.

c) Please confirm that none of the capital expenditures have previously been included in THESL's rate base.

RESPONSE:

c) None of the specific jobs for which THESL is requesting funding is included in ratebase.

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d) Please confirm that none of the projects included in the 2012, 2013 and 2014 forecasted capital are discretionary in nature.

RESPONSE:

d) Confirmed.

e) Please discuss the need for projects in the context of the actual capital spending in 2011.

RESPONSE:

e) The need for the proposed projects is extensively documented in THESL's evidence. THESL's 2011 capital spending addressed different assets than those included in the specific jobs presented in this application.

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INTERROGATORY 5:

Reference(s): none provided

Please provide a copy of all presentations and other documents provided to the Board of Directors and Senior Management supporting approval of this application and the associated budgets.

RESPONSE:

Please refer to THESL's response to CCC interrogatory 2 (Tab 6B, Schedule 6-2).

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INTERROGATORY 6:

Reference(s): none provided

Please detail the process in which the Applicant, subsequent to the release of the Board's decision in EB-2012-0144, determined which capital projects for 2012, 2013 and 2014, met the criteria for an incremental capital module.

RESPONSE:

As part of the process of constructing the present application, THESL sought to eliminate projects which, although necessary, THESL has determined do not meet the standard of urgency and priority that characterize the work included in this ICM application. THESL continues to believe that the work left out of this ICM application is nevertheless necessary and prudent and should still be undertaken by the utility over the medium to long term.

As a result, THESL has presented in this application a portfolio of projects which it believes qualify for ICM treatment under the ICM factors as discussed in the Manager's Summary at pages 14-21.

As described in the Revised Manager's Summary, the capital work included in this application was divided into ten discrete projects, some of which are divided into segments and each of which is composed of numerous jobs. THESL produced the projects and project segments by first identifying categories of necessary capital work as described above, and then populating those project segments with jobs that included such work. Necessarily, the jobs that comprise the capital projects and project segments were not carried forward wholesale from a previous application and are not grouped on the

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same basis as they would have been in prior applications. As a result, the capital portfolios used in previous applications are fundamentally incomparable with the projects and segments into which work is divided in this application.

THESL's approach to PILC capital work can be used as an example to illustrate the point above. In previous applications, the PILC portfolio focused mainly on replacing major portions of PILC cable with larger 500 MCM XLPE cables. These PILC cables were either at their end-of-life and failing, or were overloaded under first contingency conditions because they were undersized. In this application, THESL re-examined its PILC cable assets and identified only jobs that were essential (with regard to the ICM eligibility factors), and with a specific focus on those jobs that are necessary to maintain safety and system reliability, and to address possible environmental concerns. Instead of replacement, these PILC-related jobs target a specific damaged portion of leaking cable or cables requiring piecing out. In these jobs, only the smallest possible section of cable is to be replaced, usually only to a neighbouring cable chamber.

Please also see THESL's response to OEB Staff interrogatory 15 (Tab 6E, Schedule 1-15).

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INTERROGATORY 7:

Reference(s): none provided

Please explain how the ICM projects fit into the Applicant’s 10 Year Capital Plan.

RESPONSE:

The ICM projects identified and included as part of this filing represent a subset of the needed capital work across THESL’s system. Please refer to THESL’s response to SEC interrogatory 6 (Tab 6E, Schedule 10-6).

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INTERROGATORY 8:

Reference(s): none provided

For each project (and project segment), please detail how the Applicant believes the project meets the requirement for need, as defined in the *Report to the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors*, dated July 14, 2008.

RESPONSE:

The definition of need in the July 14th Report of the Board on 3rd Generation IRM contained two requirements:

1) "Amounts should be directly related to the claimed driver, which must clearly be non-discretionary."
2) "The amounts must be clearly outside of the base upon which rates were derived."

THESL submits that all its projects currently satisfy the need criterion as it was originally defined. All projects included in this application are outside of existing rates and are each linked to a claimed driver. The specific non-discretionary attribute(s) applicable to each project are presented in response to SEC interrogatory 9 (Tab 6E, Schedule 10-9).

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INTERROGATORY 9:

Reference(s): Tab 2/p.16-17

Please provide a chart that indicates, for each project category (and project segment), which categories of non-discretionary (a-e) need, the Applicant is relying on.

RESPONSE:

Please see chart on following page.

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		Statute, Code, or external requirement (a)	Public and Employee Safety (b)	Immenent Reliability Degradations (c)	Immenent Capacity Shortages (d)	Material Increase in Cost (e)
	Underground Infrastructure and Cable					
B1	Underground Infrastructure		x	x		
B2	Paper Insulated Lead Covered Cable - Piece Outs and Leakers		x	x		
B3	Handwell Replacement		x			
	Overhead Infrastructure and Equipment					
B4	Overhead Infrastructure		x	x		
B5	Box Construction		x	x	x	x
B6	Rear Lot Construction		x	x		x
B7	Polymer SMD-20 Switches		x	x		
B8	SCADA-Mate R1 Switches		x	x		
	Network Infrastructure and Equipment					
B9	Network Vault & Roofs		x	x		
B10	Fibertop Network Units		x	x		
B11	Automatic Transfer Switches (ATS) & Reverse Power Breakers (RPB)		x	x		
	Station Infrastructure and Equipment					
B12	Stations Power Transformers		x	x	x	
B13	Stations Switchgear - Muncipal and Transformer Stations			x		
B14	Stations Circuit Breakers		x	x		
B15	Stations Control & Communicaton Systems			x		
B16	Downtown Station Load Transfers			x		
B17	Bremner Transformer Station	x		x	x	x
B18	Hydro One Capital Contributions	x			x	
B19	Feeder Automation			x		
B20	Metering	x				
B21	Externally-Initiated Plant Relocations and Expansions	x				x

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INTERROGATORY 12:

Reference(s): **Tab 1, page 3, lines 24-26**
Tab 2, page 3, lines 8-9

a) Please indicate specifically which Board Decisions on other distributors' IRM applications that included a request for relief pursuant to the Board's Incremental Capital Module THESL has relied on.

RESPONSE:

a) In preparing its IRM/ICM application, THESL reviewed the applications, and corresponding decisions as available, of all utilities that had applied under the ICM module. These included:

1. Hydro One Networks Inc (EB-2008-0187)
2. Oshawa PUC Networks Inc (EB-2008-0205)
3. Oakville Hydro Electric Distribution Inc (EB-2010-0104)
4. Guelph Hydro Electric Systems Inc (EB-2010-0130)
5. Kingston Hydro Corporation (EB-2011-0178)
6. Centre Wellington Hydro Ltd (EB-2011-0160)

b) Are there any particular directions in these Decisions that guided THESL's preparation of the current Application? If yes, please indicate what they are.

RESPONSE:

b) THESL found that the above-noted decisions were of assistance in guiding its approach to its ICM application, including in its understanding of the ICM factors and their specific application. Such understanding is detailed in THESL's Revised

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Manager's Summary and applied in the context of its pre-filed ICM evidence at Tab 4 of the application. THESL also took direction from the way in which these decisions, viewed as a whole and in combination with the OEB's other guidelines and directions, illustrate how the OEB's approach to the ICM is evolving.

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INTERROGATORY 13:

Reference(s): **Tab 1, page 5, Footnote #1**
Tab 2, page 7, lines 23-24 and page 22, lines 9-21

a) The Application indicates that it is THESL's "understanding" that the Board's ICM includes a true-up of the actual revenue received under the ICM rate adders versus the ultimately approved amount and that any variance is refunded to/collected from customers in the next cost of service rate year. Please provide the Board Policy/Decision references that form the basis for this understanding.

RESPONSE:

a) Please refer to THESL's response to OEB Staff interrogatory 22 (Tab 6E, Schedule 1-22).

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INTERROGATORY 14:

Reference(s): Tab 2, page 14, lines 17-23

a) THESL states that it is addressing the criteria cited specifically by the Board in its EB-2011-0144 Decision in reference to a potential ICM application by THESL. Please indicate what specific criteria THESL is referring to.

RESPONSE:

a) With respect, this section of THESL's evidence does not state that THESL "is addressing the criteria cited specifically by the Board in its EB-2011-0144 Decision," although as stated in the Revised Manager's Summary, THESL has considered and sought to incorporate/address the OEB's reasons and commentary as contained in its decision in EB-2011-0144, including the specific ICM factors it noted in that decision. In this regard, THESL takes note of the following excerpt from the OEB's EB-2011-0144 Decision:

> "The Board's thinking in this area has evolved, and in the recent ICM decisions the Board has granted rate relief for discrete, material and non-discretionary projects which cannot be funded through the normal operation of the 3GIRM mechanism."

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INTERROGATORY 15:

Reference(s): **Tab 2, page 15, lines 8-10 and page 16, lines 20-21 & 27-30**

a) For each Project, please indicate whether it is new for 2012 or whether the approved 2011 revenue requirement included jobs related to the project. For example, with the respect to the project discussed in Tab 4, Schedule B1, did the 2011 approved revenue requirement and associated capital spending include jobs addressing the replacement of direct buried cable with cable in concrete-encased ducts?

RESPONSE:

a) The proposed ICM projects consist only of work that has not been previously undertaken. The projects and project segments proposed in this application consist of specific pieces of work (jobs) that THESL has not previously undertaken but which may be similar to the type of work that THESL has done before and for which funding has been approved in previous years. For example, THESL has had in the past and has now direct buried cable that serves many geographically dispersed areas in the city. Much of that failing cable has been replaced under previous approvals; much remains to be replaced.

b) If the 2011 approved revenue requirement included jobs associated with the project, please indicate the amount of spending for such jobs: i) included in THESL's 2011 Rate Application, ii) included in THESL's approved 2011 capital spending, and iii) included in THESL's actual 2011 capital spending. Also, for each such project, please indicate why it is considered "new and incremental to the rebasing year (2011) revenue requirement".

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RESPONSE:

b) Please see THESL's response to OEB Staff interrogatory 26 (e) (Tab 6F, Schedule 1-26).

c) For those Projects identified in response to part (a), please reconcile THESL's request for ICM treatment with the Board's EB-2008-0187 Decision (pages 7-9) which deemed that such projects were not eligible for ICM treatment.

RESPONSE:

c) The OEB's decision in Hydro One's EB-2008-0187 proceeding reflected the OEB's views at the time it was made. As stated in the EB-2011-0144 decision, the OEB's thinking with respect to the ICM criteria has evolved. THESL believes that the circumstances under which it must undertake the proposed capital expenditures are unusual and has explained the basis for this in evidence. Furthermore, in light of the EB-2011-0144 decision, this ICM application appears to be the only avenue currently available through which THESL can secure the funding which it requires in order to undertake this work. THESL has no other alternative under which to seek funding for this essential capital work.

d) Does the anticipated spending on any of the proposed ICM projects extend beyond 2014? If yes, please identify the project and provide the anticipated annual spending post-2014 through to completion.

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RESPONSE:

d) As stated in THESL's Revised Manager's Summary, THESL estimates that in any year approximately one third of the projects it undertakes may carry over into the following year.

e) If the response to part (d) is yes, please reconcile this with the statement on page 16 that "every project addresses a well-defined need that must be met in the short-term".

RESPONSE:

e) There is no contradiction between these statements requiring reconciliation. THESL believes that the work proposed in this application is essential and should be undertaken over the period covered by this application. Some of the work begun over that period may not be completed by December 31, 2014.

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INTERROGATORY 16:

Reference(s): Tab 2, page 16, lines 3-5 Tab 4, Schedule A, Appendix 1, page 1

a) How much of the capital spending for each year (as set out in Tab 4) is for facilities that will actually be in-service by the end of the year in which the capital is reported as being spent?

b) If all the capital spending set out in Tab 4 will not be in-service the same year in which the spend occurs, please provide a schedule that sets out for each of 2012 through 2014 year ends, the capital spending that is "in-service" versus "work-in-progress".

RESPONSE:

a) and b)

THESL has advised the OEB and intervenors that it will be filing an update to its pre-filed evidence. THESL believes that its pending update will fundamentally affect THESL's response to this interrogatory, such that providing a response now would not materially assist the OEB or intervenors. THESL accordingly defers its response to this interrogatory until after its forthcoming evidentiary update.

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INTERROGATORY 17:

Reference(s): Tab 2, page 23, lines 1-2

Preamble:

The Board's ICM filing requirements as set out on pages VI and VII of Appendix B in the Supplementary require the Applicant to provide a description of the actions the distributor will take in the event that the Board does not approve the application.

a) Is it THESL's position that it will not undertake the proposed capital spending if the ICM request is not approved (per the statement on page 23)?

RESPONSE:

a) On a planned basis, THESL will expect to operate within the resource envelope approved by the OEB in this proceeding. If unforeseen critical contingencies arise after the decision is released, THESL may be required to re-prioritize the deployment of its remaining resources to meet the most critical needs.

b) If yes, what actions will THESL take to address/manage the issues identified in the Application?

RESPONSE:

b) Please see THESL's response to OEB Staff interrogatory 10 (Tab 6A, Schedule 1-10).

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c) What is the current status of the ICM spending proposed for 2012? Please provide a schedule that sets out the actual 2012 spending to date for each project.

RESPONSE:

c) THESL has advised the OEB and intervenors that it will be filing an update to its pre-filed evidence. THESL believes that its pending update will fundamentally affect THESL's response to this interrogatory, such that providing a response now would not materially assist the OEB or intervenors. THESL accordingly defers its response to this part of the interrogatory until after its forthcoming evidentiary update.

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INTERROGATORY 18:

Reference(s): Tab 2, Appendix 2, page 1

a) Please provide a schedule that sets out THESL's actual 2010 distribution billing determinants by customer class, its approved 2011 distribution billing determinants by customer class and its actual 2011 distribution billing determinants by customer class.

b) Using the approved 2011 rates please provide the revenues by class and total revenues associated with each of the three sets of billing determinants.

RESPONSE:

a) and b)

Please see the attached Appendix A.

		Billing Units			Rates	Distribution Revenue @ 2011 Rates		
		2010 Actual	2011 Board-approved	2011 Actual	2011 Board-approved	2010 Actual	2011 Board-approved	2011 Actual
Residential								
Customer Charge	Cust	591,496	598,508	599,751	18.25	$129,537,624	$131,073,252	$131,345,469
Distribution Charge	kWh	5,105,974,275	4,886,977,489	5,072,793,809	0.01507	$76,947,032	$73,646,751	$76,447,003
Competitive Sector Multi-Unit Residential								
Customer Charge	Cust	24,898	24,898	24,898	17.00	$5,079,192	$5,079,192	$5,079,192
Distribution Charge	kWh	99,791,184	99,791,184	99,791,184	0.02565	$2,559,644	$2,559,644	$2,559,644
General Service <50 kW								
Customer Charge	Cust	65,799	65,792	66,681	24.30	$19,186,988	$19,184,993	$19,444,180
Distribution Charge	kWh	2,095,343,918	2,139,318,076	2,085,458,504	0.02247	$47,082,378	$48,070,477	$46,860,253
General Service 50-999 kW								
Customer Charge	Cust	12,873	13,067	12,845	35.56	$5,493,167	$5,575,758	$5,481,218
Distribution Charge	kVA	26,712,248	26,935,191	26,844,224	5.5956	$149,471,055	$150,718,556	$150,209,538
General Service 1000-4999 kW								
Customer Charge	Cust	509	514	503	686.46	$4,192,898	$4,234,085	$4,143,473
Distribution Charge	kVA	10,972,419	10,587,119	10,611,793	4.4497	$48,823,974	$47,109,505	$47,219,294
Large Users								
Customer Charge	Cust	47	47	50	3009.11	$1,697,138	$1,697,138	$1,805,466
Distribution Charge	kVA	5,267,224	4,993,733	5,441,751	4.7406	$24,969,801	$23,673,292	$25,797,165
Streetlighting								
Customer Charge	Conn	162,964	162,777	163,071	1.30	$2,542,238	$2,539,322	$2,543,908
Distribution Charge	kVA	321,995	322,023	322,481	28.7248	$9,249,232	$9,250,042	$9,263,211
Unmetered Scattered Load								
Customer Charge	Cust	1,107	1,130	1,113	4.84	$64,295	$65,611	$64,645
Distribution Charge	kWh	52,097,299	56,231,585	42,758,509	0.06070	$3,162,306	$3,413,257	$2,595,441
Connection Charge	Conn	12,159	21,729	12,499	0.49	$71,494	$127,767	$73,494
Total Distribution Revenue						$530,130,455	$528,018,642	$530,932,592

Notes:
1) Revenues not adjusted for days of service
2) Competitive Sector Multi-Unit Residential class biling units in 2010 assumed same as 2011
3) Does not include Transformer Allowance

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INTERROGATORY 19:

Reference(s): **Tab 4, Schedule E1.1, page 11**

a) Please provide fully accessible versions of the ICM models that allow parties to see the derivation of the Incremental Capital CAPEX (e.g. $275,754,831 for 2012).

RESPONSE:

a) THESL has advised the OEB and intervenors that it will be filing an update to its pre-filed evidence. THESL believes that its pending update will fundamentally affect THESL's response to this interrogatory, such that providing the excel versions of the requested evidence now would not materially assist the OEB or intervenors. THESL accordingly defers providing the requested workbooks until after its forthcoming evidentiary update.

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INTERROGATORY 23:

Reference(s): **T2/p. 2**

It is stated that:

> "The specific projects THESL includes within the ICM reflect the minimum amount of infrastructure renewal THESL must undertake over the next three years to maintain current overall levels of system safety and reliability."

Please comment on whether or not there have been any significant changes in THESL's service quality and reliability statistics in the time since the filing of the EB-2011-0144 application.

RESPONSE:

THESL has been able to maintain relatively stable reliability over the referenced period. 2011 year-end reliability was on par with what was expected, and the 2012 year to date (August-end) reliability indicators have been lower (i.e., better) than expectations. This can be attributed in part to reduced weather-related outages resulting from a mild winter and summer.

THESL does not consider its current reliability results to be "good". Average reliability statistics mask reliability degradations in specific locations that are essential to address. In addition, THESL notes that over short intervals, reliability statistics can fluctuate according to short-term influences such as the severity of weather and changes in the amount of work being done on the system.

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INTERROGATORY 24:

Reference(s): **T2/p. 2**

It is stated that "the specific projects set out in the application generally span the whole three year period and are generally constituted of individual jobs."

Subsequently in the same reference, it is stated that:

> "However, as explained below, the timing of each job within the different projects may vary from the forecast, in order to allow for contingencies that arise when undertaking such a large and widespread construction program. For example, a specific job within a project could be delayed due to unforeseeable external factors such as changes in the infrastructure plans of the City or other utilities, or permitting issues. In such cases, THESL would be required to advance another job in order to manage and optimize work flow and avoid a situation of underutilized resources."

Please state whether or not such delays could lead to additional projects rather than jobs within projects being substituted and, if so, what THESL would see the implications of incorporating additional projects as being.

RESPONSE:

THESL does not foresee any new projects arising as a result of timing variances at the job level within projects.

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INTERROGATORY 25:

Reference(s): T2/p. 10

It is stated that:

> "The costs of the ICM projects proposed in this Application are estimated based on the existing contracts between THESL and its contractors. However, the availability of this pricing may be contingent on both the level and predictability of the work that THESL can offer to those contractors."

a) Please expand on what is meant by "the level and predictability of the work" in the above statement.

RESPONSE:

a) The 'level' of work refers to the (dollar) volume of work THESL makes available to contractors. The 'predictability' of the work refers to whether the volume of work in a future period (e.g., next year) can be predicted with reasonable confidence sufficiently prior to the start of that period to enable contractors to assemble the resources necessary to accomplish the expected level of work.

b) Do THESL's arrangements with its contractors contain any 'out' clauses related to the referenced contingencies? If yes, please state what they are.

RESPONSE:

b) The contractors have no clauses related to termination of the contracts for the level or predictability of the work, as such contracts do not typically provide for a guaranteed minimum or maximum amount of work. The contractors will, however, have

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difficulty undertaking work if they lack available labour resources or specific required skill-sets. For example, labour resources with skills in PILC cable installation and jointing or in working on overhead box construction are typically difficult to obtain. THESL will necessarily have greater difficulty entering into contracts and face higher costs for contracts that it enters into should the level of the work be limited and if the predictability of the work is uncertain.

c) In the event THESL was unable to obtain from its contractors the pricing which it has assumed in this application, what actions would it envisage taking?

RESPONSE:

c) Since pricing is fixed by each contractor’s unit price bids, a reduction in the expected level of work could result in the inability of a contractor to attract resources to undertake the (reduced) level of work. In this situation, THESL would likely have to tender specific jobs, which would be bid on individually by the contractor firms and would likely include cost premiums to attract resources.

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INTERROGATORY 26:

Reference(s): **T4/S A/App. 1 and *Filing Requirements for Electricity Transmission and Distribution Applications*, June 28, 2012, Ch. 3**

On page 8 of Chapter 3 of the Filing Requirements, it is stated that:

> "A distributor applying for recovery of incremental capital should calculate the eligible incremental capital amount by taking the difference between the 2012 total non-discretionary capital expenditure and the materiality threshold." [emphasis added].

The first reference is to the "Summary of the Capital Program provided by THESL which is a table listing the various projects that make up THESL's requests in the present application:

a) Please state the definition of 'non-discretionary' that THESL is using for the purposes of this application. If the definition includes more than one factor, please provide at least one example for each factor from this application.

RESPONSE:

a) Please refer to the Revised Manager's Summary discussion of this issue under the headings 'Need' and 'Safety Considerations Pertinent to Need' at pages 16-19. Please also refer to THESL's responses to SEC interrogatories 8 and 9 (Tab 6E, Schedules 10-8 and 10-9).

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b) Please provide a priority ranking for each of the projects listed in this table from Schedule Number B1 to B22 from "1" for most important to "22" for least important.

RESPONSE:

b) THESL does not believe that the projects can be ranked in terms of priority. The projects in THESL's application have been identified and included because they meet the ICM eligibility factors, are essential to maintain the safety and reliability of the distribution system and THESL has no other options to fund them at this time. While THESL can only implement a limited number of jobs in a given year for a variety of reasons (including resource availability, project planning constraints, external factors such as availability and timing of permits, etc.), each aggregate project contains jobs that require more or less equally essential work.

c) For each of the years 2012 to 2014, please break down the amounts in this table into assets that will be in service in the year in question versus those which will be in service in subsequent years.

RESPONSE:

c) THESL has advised the OEB and intervenors that it will be filing an update to its pre-filed evidence. THESL believes that its pending update will fundamentally affect THESL's response to this interrogatory, such that providing a response now would not materially assist the OEB or intervenors. THESL accordingly defers its response to this part until after its forthcoming evidentiary update.

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d) Please state how much of the capital program outlined in this table was not included in the capital program proposed by THESL in the EB-2011-0144 application.

RESPONSE:

d) Of the jobs comprising the capital program outlined in the referenced table, $120.89M was not included in the capital program identified by THESL in the EB-2011-0144 application.

e) Please state how much of the capital program proposed in this application was not included in the capital program proposed by THESL in the EB-2010-0142 application.

RESPONSE:

e) Of the jobs comprising the capital program outlined in the referenced table, $1,371.33M was not included in the capital program as filed by THESL in its EB-2010-0142 application. As stated in the Revised Manager's Summary, the ICM projects and associated jobs are new and incremental to the rebasing year (2011) revenue requirement. The limited overlap between capital work that was originally proposed in THESL's 2011 application (EB-2010-0142) and this application consists of:

(i) continuing capital work that was begun in 2011 and scheduled to be completed in 2012 (see Tab 4, Schedule C1, pp. 7-9), and

(ii) non-discretionary jobs initially proposed for construction in 2011 that could not proceed due to the unique circumstances of each job. No capital work was previously undertaken (i.e., prior to 2012) in respect of jobs in this category.

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INTERROGATORY 27:

Reference(s): **T2/App. 4, T4/S B11/pp. 22-23 and T4/S B16/pp. 10-11**

The first reference explains in detail the theoretical constructs of the "Feeder Investment Model" ("FIM"), and the theoretical constructs of the Model for the "Cost of Ownership" ("COO").

The second reference discusses an outage cost based on $30 per customer per interruption and $15 per kWh interrupted.

The third reference discusses an outage cost based on $30/kW outage event cost and $15 per kWh outage duration cost.

a) Please explain the apparent differences between the basis of the two referenced customer interruption costs.

RESPONSE:

a) The two references use consistent customer interruption costs. In both cases the applied customer interruption costs (CICs) are as follows:

i. CIC = Event Cost + Duration Cost

ii. Event Cost = ($SAIFI_{EFFECT}$)(Total Load)
Where:
- $SAIFI_{EFEECT}$ ($30) represents the cost associated with the occurrence of the interruption.

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- Total Load represents the peak load in kVA that will be interrupted due to the outage event.

iii. Duration Cost = ($SAIDI_{EFFECT}$)(Total Load)(Outage Duration)
Where:
- $SAIDI_{EFEECT}$ ($15) represents the cost associated with the duration of the interruption.
- Total Load represents the peak load in kVA that will be interrupted due to the outage event.
- Outage Duration represents the average duration of the outage event in hours.

b) Please clarify whether or not a fixed set of referenced customer interruption costs are used for all customer interruptions in all the FIM and COO type business case evaluations, and if so please provide that fixed set.

RESPONSE:

b) As noted in (a), THESL has adopted the use of a $30/kVA (peak load) customer interruption cost value to represent the outage occurring (The “Event”) and a $15/kVA-hour (peak load) customer interruption cost value to represent the length of the outage (The “Duration”). These costs are adopted within every FIM and COO business case evaluation presented within the ICM filing.

c) Please provide supporting evidence/calculations justifying this cost.

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RESPONSE:

c) The customer interruption costs applied by THESL as part of every FIM and COO business case were developed with consultants, who have worked with other utilities in establishing similar parameters. Reliability valuation studies, such as those from Roy Billinton, were used to aid in the development of these parameters, which are applied consistently to quantify power interruptions to all types of customers.

Figure 1 and chart 1 illustrate how THESL's customer interruption costs compare to those established via reliability valuation studies. Figure 1 illustrates the total cost of a four-hour outage using these various customer interruption costs. Those employed by THESL are shown in red. Table 1 shows the Event Cost per Customer and Duration Cost per Customer-Hour using each of these customer interruption costs, including those employed by THESL. The chart also contains the source of the information shown in the blue bars in Figure 1, and in Table 1, THESL's customer interruption costs are within the range of the other sampled costs. In addition, THESL has also confirmed that the current customer duration cost employed by THESL is within the range of customer duration costs used by Hydro One Networks Inc.

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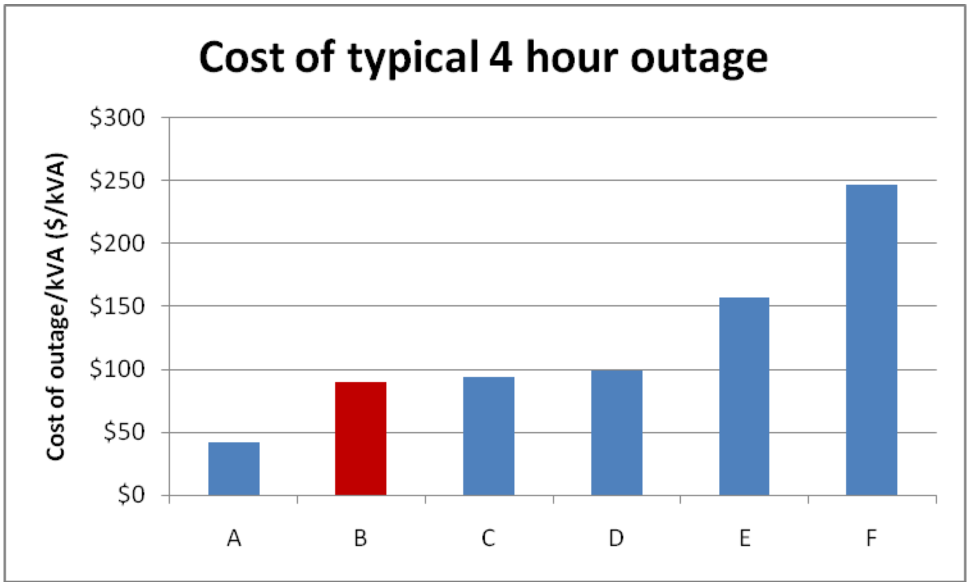

1 **Figure 1 – Cost of a Typical 4-Hour Outage**

2 **Table 1 – Customer Interruption Cost Breakdown**

	Study Name	Duration Cost ($/kVA)	Event Cost ($/kVA)	Reference	Page Number on PDF
A	Interruption Costs Netherlands	8.721	6.579	N/A	4
B	THESL	15	30	N/A	N/A
C	The Use of Customer Outage Cost Surveys in Policy Decision-Making	14.436	35.982	N/A	5
D	Consumer Expectations of DNOs and WTP for Improvements in Service	22.539	8.769	Table 29	35
E	Economic Valuation of Electrical Service Reliability	17.631	86.652	N/A	9
F	How to Estimate the Value of Service Reliability Improvements	50.94	42.93	Table 1	3

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INTERROGATORY 28:

Reference(s): T4/S B1/p. 197 and pp. 2-3

Table 1 of the first reference provides "Avoided Estimated Risk Cost for Underground Infrastructure Segment." and shows an "Avoided Estimated Risk Cost" of $230 million for this segment.

Table 1 of the second reference provides a list of jobs to be executed in 2012, 2013 and 2014.

In order to have an illustrative example of THESL's approach so that this methodology may be more clearly understood, please provide further detailed information, as suggested in the tables below for each of the projects in Table 1 of the second reference, related to the calculation of the "Avoided Estimated Risk Cost" using the Underground Infrastructure Segment.

Should THESL believe changes to these tables are necessary, please make any such changes and provide a detailed explanation of them. Please specify any discount rates used.

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(millions)

#	Job Title	Conditional probability of Failure ($ 000)	Direct Costs ($ 000)	Indirect Costs ($ 000)		Total Net Present Value in 2012 for Cost of Replacing Equipment in 2015 ($ 000)
				Cost of Customer Interruptions ($ 000)	Other Indirect Costs ($ 000)	
1	Underground Rehab. Of Feeder NY80M29					
2	Underground Rehab. Of Feeder SCNAR26M34					
Etc.						
Present Value of Project Net Cost in 2015						**$354**

#	Job Title	Value of Sacrificed Assets	Value of Excess Risk Assets	Concurrent Intervention Benefits	Net Project Benefit	Project Net Cost 2012
1	Underground Rehab. Of Feeder NY80M29					
2	Underground Rehab. Of Feeder SCNAR26M34					
Etc.						
Project Net Cost in 2012						**$124**

RESPONSE:

The tables below provide detailed information associated with the calculation of "Avoided Estimated Risk Cost." Please note that the Avoided Estimated Risk Cost and the "Project Net Costs" in the table below has been revised to correct an error in the evidence. In calculating the present value of the 2015 figure, THESL inadvertently

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applied both an annual discount rate to the years 2013, 2014 and 2015 and an overall rate to the 2015 figure. This response also corrects Table 1 on page 197 of Tab 4, Schedule B1.

The information is provided both at the job level as well as at the asset level, as certain portions of the calculation must be produced at the asset level, while other portions must be produced at the job level. Table 1 provides a summary of the Avoided Risk Cost result by job, while Table 2 provides the detailed calculations that must take place at the asset level in order to calculate this Avoided Risk Cost value.

Variables such as "Conditional Probability of Failure" (Failure Probability), "Direct Costs" & "Indirect Costs" are only calculated at the asset level (Table 2), while "Concurrent Intervention Benefits", "Net Project Benefit" and "Project Net Costs" are calculated at the job level in Table 1. Also, "the Cost of Deviating from Optimal Intervention" represents the total costs associated with the job, including both Excess Risk and Sacrificed Life. This is calculated on the asset level shown in Table 2, which can then be summed to obtain the project level Cost of Deviation from Optimal Intervention shown in Table 1. The discount rate used in both tables is THESL's corporate discount rate of 6.06%.

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1 **Table 1 – Avoided Risk Cost Results by Job**

Job #	Job Feeder Name	Job Cost ($M)	PV (2015 Cost of Deviating from Optimal Intervention) ($M)	2012 Cost of Deviating from Optimal Intervention ($M)	2012 Concurrent Intervention Benefit ($M)	PV (2015 Net Project Benefit) ($M)	2012 Net Project Benefit ($M)	PV (2015 Project Net Cost) ($M)	2012 Project Net Cost ($M)	Three Year Avoided Risk Cost ($M)
1	NY80M29	$2.90	$31.58	$26.56	$2.12	$26.71	$31.87	$4.87	-$5.31	$10.18
2	SCNAR26M34	$5.52	$28.06	$22.52	-$2.05	$26.11	$31.15	$1.95	-$8.63	$10.58
3	NY55M8	$2.49	$4.13	$5.17	-$0.46	$2.62	$3.13	$1.51	$2.05	-$0.54
4	NY35M10	$2.14	$7.30	$8.42	-$0.45	$5.99	$7.14	$1.31	$1.28	$0.03
5	SCNT63M4	$3.16	$15.01	$12.13	$5.31	$18.90	$22.54	-$3.89	-$10.41	$6.52
6	SCNA47M14	$4.43	$7.11	$8.93	-$0.33	$7.52	$8.98	-$0.41	-$0.05	-$0.36
7	NY51M6	$2.54	$9.53	$5.54	$1.65	$9.18	$10.95	$0.35	-$5.42	$5.77
8	NY80M8	$9.51	$5.01	$6.27	-$6.58	-$1.89	-$2.26	$6.90	$8.53	-$1.63
9	NY85M6	$2.01	$26.94	$20.80	-$0.18	$17.27	$20.61	$9.66	$0.19	$9.47
10	NY51M8	$1.58	$6.39	$7.69	-$0.46	$4.66	$5.56	$1.73	$2.12	-$0.39
11	SCNA502M22	$2.96	$14.41	$18.59	$2.01	$16.22	$19.35	-$1.80	-$0.76	-$1.05
12	SCNAH9M30	$3.56	$14.65	$17.06	-$0.86	$10.87	$12.97	$3.77	$4.08	-$0.31
13	NY85M4	$8.27	$45.85	$45.99	$0.37	$45.45	$54.23	$0.40	-$8.24	$8.64
14	SCNA47M13	$4.91	$13.41	$16.17	-$0.08	$11.69	$13.95	$1.72	$2.22	-$0.51
15	NY80M2	$1.63	$16.19	$18.73	$3.02	$22.29	$26.59	-$6.10	-$7.86	$1.77
16	NY51M7	$1.40	$2.02	$2.58	-$0.16	$1.08	$1.29	$0.94	$1.29	-$0.35
17	NY51M24	$5.64	$16.39	$11.98	$2.84	$21.52	$25.68	-$5.13	-$13.70	$8.57
18	NY80M30	$8.95	$20.59	$23.81	-$6.17	$26.26	$31.33	-$5.68	-$7.53	$1.85
19	NY55M23	$2.24	$6.73	$8.18	-$0.97	$4.53	$5.40	$2.21	$2.78	-$0.58
20	NY85M24	$2.03	$38.92	$45.63	$3.10	$40.76	$48.63	-$1.84	-$3.01	$1.17
21	SCNAE5-2M3	$1.51	$4.96	$4.29	-$0.34	$2.84	$3.38	$2.12	$0.90	$1.22
22	NY85M7	$13.83	$5.95	$7.83	-$5.73	$0.04	$0.04	$5.91	$7.78	-$1.87
23	SCNT63M12	$11.14	$67.17	$72.77	$9.28	$97.93	$116.83	-$30.76	-$44.06	$13.30
24	SCNT63M8	$7.59	$15.31	$11.76	$1.28	$21.69	$25.87	-$6.38	-$14.12	$7.74

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Job #	Job Feeder Name	Job Cost ($M)	PV (2015 Cost of Deviating from Optimal Intervention) ($M)	2012 Cost of Deviating from Optimal Intervention ($M)	2012 Concurrent Intervention Benefit ($M)	PV (2015 Net Project Benefit) ($M)	2012 Net Project Benefit ($M)	PV (2015 Project Net Cost) ($M)	2012 Project Net Cost ($M)	Three Year Avoided Risk Cost ($M)
25	SCNAE5-1M29	$3.91	$21.22	$21.57	$1.91	$21.26	$25.36	-$0.04	-$3.79	$3.75
26	NY53M25	$3.44	$11.36	$12.65	$0.30	$19.03	$22.71	-$7.67	-$10.06	$2.39
27	NY80M9	$2.21	$24.97	$30.82	-$0.10	$24.01	$28.64	$0.96	$2.17	-$1.22
28	SCNT47M3	$20.44	$98.58	$115.93	$3.80	$118.05	$140.83	-$19.46	-$24.90	$5.44
29	SCNAH9M23	$2.71	$18.85	$12.30	$0.28	$13.20	$15.74	$5.65	-$3.45	$9.10
30	NY51M3	$3.54	$11.04	$13.21	$1.02	$8.33	$9.93	$2.71	$3.28	-$0.56
31	SCNA47M17	$5.70	$29.39	$21.07	$1.14	$41.40	$49.39	-$12.01	-$28.32	$16.30
32	SCNA502M21	$3.44	$27.96	$26.80	$0.71	$38.59	$46.04	-$10.63	-$19.25	$8.62
33	SCNT47M1	$14.91	$180.12	$153.35	-$4.43	$276.61	$330.00	-$96.48	-$176.66	$80.17
34	NY85M1	$2.66	$9.52	$4.59	-$0.69	$2.81	$3.35	$6.71	$1.24	$5.47
Total		$174.90	$856.60	$841.65	$10.10	$1,003.52	$1,197.24	-$146.92	-$355.59	**$208.68**

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1 **Table 2 – Asset-Level Calculations**

Job #	Asset Identifier	Failure Probability	Direct Cost ($)	Indirect Cost ($)		PV (2015 Cost of Deviation from Optimal) ($)	2012 Cost of Deviation from Optimal ($)
				Customer Interruption Cost ($)	Other Indirect Cost ($)		
1	1220945	3.68%	$491	$0	$5,000	$435,078	$0
1	1220973	3.68%	$491	$0	$5,000	$435,078	$0
1	1220977	3.68%	$491	$0	$5,000	$435,078	$0
1	1663897	1.04%	$408	$0	$4,500	$52,679	$0
1	1663912	1.04%	$408	$0	$4,500	$52,679	$0
1	1663913	1.04%	$408	$0	$4,500	$52,679	$0
1	1663914	1.04%	$408	$0	$4,500	$52,679	$0
1	1663916	1.04%	$408	$0	$4,500	$52,679	$0
1	1663917	1.04%	$408	$0	$4,500	$52,679	$0
1	1664118	1.32%	$783	$0	$4,000	$1,576	$6,921
1	1664125	1.32%	$441	$0	$4,500	$163,836	$0
1	1664129	0.43%	$580	$18,720	$2,800	$19	$166
1	1664130	0.43%	$580	$3,900	$2,800	$337	$578
1	1664135	1.17%	$408	$0	$4,500	$2,083	$0
1	1664137	1.17%	$408	$0	$4,500	$2,083	$0
1	1664140	1.48%	$783	$0	$4,000	$2,644	$8,451
1	1668984	0.02%	$416	$4,032,737	$8,000	$1,431,005	$1,732,237
1	1669875	0.00%	$416	$4,032,737	$8,000	$1,521,660	$1,819,485
1	1669998	0.06%	$416	$4,032,737	$8,000	$1,364,303	$1,658,837
1	1670719	0.02%	$720	$180,000	$8,000	$46,204	$55,752
1	1671188	0.00%	$720	$180,000	$8,000	$48,648	$58,277
1	1674243	0.00%	$416	$4,032,737	$8,000	$1,521,756	$1,819,569
1	1677369	0.04%	$383	$79,688	$8,000	$32,625	$40,071
1	1677489	0.05%	$383	$79,688	$8,000	$32,032	$39,570

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES ON ISSUE 2.2

Job #	Asset Identifier	Failure Probability	Direct Cost ($)	Indirect Cost ($)		PV (2015 Cost of Deviation from Optimal) ($)	2012 Cost of Deviation from Optimal ($)
				Customer Interruption Cost ($)	Other Indirect Cost ($)		
1	1677719	0.00%	$383	$1,734,469	$8,000	$678,864	$818,153
1	1678294	70.11%	$1,795	$4,337,094	$0	$8,954,146	$0
1	1679831	0.07%	$383	$133,688	$8,000	$49,022	$61,002
1	1681035	0.07%	$720	$15,000	$8,000	$8,216	$10,240
1	1681091	0.42%	$416	$4,032,737	$8,000	$780,114	$1,053,342
1	1681625	0.03%	$383	$1,734,469	$8,000	$630,658	$769,813
1	1682884	1.64%	$1,746	$140,818	$0	$44,494	$71,878
1	1683264	0.01%	$383	$133,688	$8,000	$59,286	$71,197
1	1684124	0.10%	$383	$1,734,469	$8,000	$532,232	$674,560
1	1684299	1.68%	$1,746	$34,563	$0	$44,071	$61,018
1	1684514	4.40%	$1,746	$24,688	$0	$13,541	$21,320
1	1685237	2.10%	$1,746	$34,563	$0	$49,505	$69,168
1	1685395	12.77%	$1,746	$140,818	$0	$2,227	$9,808
1	1685429	0.03%	$383	$79,688	$8,000	$33,651	$40,954
1	1686536	0.04%	$383	$1,734,469	$8,000	$611,292	$751,168
1	1686654	0.00%	$383	$133,688	$8,000	$57,326	$68,584
1	1687572	0.12%	$383	$133,688	$8,000	$47,240	$60,253
1	1687896	0.04%	$383	$133,688	$8,000	$54,101	$66,390
1	1688276	1.19%	$1,746	$32,094	$0	$37,763	$51,216
1	1689030	2.15%	$1,746	$32,094	$0	$51,054	$70,845
1	1689756	8.43%	$1,746	$140,818	$0	$32,080	$83,234
1	1690012	0.00%	$383	$133,688	$8,000	$57,321	$68,580
1	1690803	1.65%	$1,746	$32,094	$0	$44,064	$60,552
1	1691454	3.83%	$1,746	$140,818	$0	$35,289	$70,387
1	1691700	7.01%	$1,746	$24,688	$0	$14,244	$23,983
1	1692530	0.03%	$383	$79,688	$8,000	$33,495	$40,818

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES ON ISSUE 2.2

Job #	Asset Identifier	Failure Probability	Direct Cost ($)	Indirect Cost ($)		PV (2015 Cost of Deviation from Optimal) ($)	2012 Cost of Deviation from Optimal ($)
				Customer Interruption Cost ($)	Other Indirect Cost ($)		
1	1693007	4.02%	$1,746	$34,563	$0	$75,355	$107,598
1	1694495	0.07%	$383	$1,734,469	$8,000	$568,386	$709,696
1	1696463	0.00%	$383	$79,688	$8,000	$36,042	$43,084
1	1696730	0.08%	$383	$1,734,469	$8,000	$556,621	$698,286
1	1696837	0.03%	$383	$1,734,469	$8,000	$630,457	$769,621
1	1696879	0.06%	$383	$133,688	$8,000	$52,814	$65,226
1	1697487	0.04%	$383	$1,734,469	$8,000	$624,377	$763,770
1	1697780	0.08%	$383	$1,734,469	$8,000	$561,867	$703,377
1	1698337	0.00%	$720	$22,500	$8,000	$12,553	$15,052
1	1698962	2.09%	$1,746	$32,094	$0	$50,114	$69,468
1	1699002	0.85%	$1,746	$34,563	$0	$33,742	$45,255
1	1699390	0.06%	$383	$79,688	$8,000	$31,895	$39,456
1	1699440	0.12%	$383	$1,734,469	$8,000	$504,717	$647,698
1	1701088	0.25%	$383	$1,734,469	$8,000	$402,475	$546,619
1	1702196	0.01%	$383	$133,688	$8,000	$59,313	$71,220
1	1703019	0.02%	$383	$79,688	$8,000	$34,116	$41,359
1	1703233	0.12%	$383	$133,688	$8,000	$47,244	$60,256
1	1704753	0.09%	$383	$1,734,469	$8,000	$539,001	$681,159
1	1705289	3.56%	$1,746	$140,818	$0	$35,477	$69,603
1	1707179	2.63%	$1,746	$83,938	$0	$43,708	$70,448
1	1707717	1.07%	$1,746	$34,563	$0	$36,319	$49,270
1	1707781	0.00%	$720	$15,000	$8,000	$8,040	$9,634
1	1707986	0.21%	$383	$1,734,469	$8,000	$428,641	$572,698
1	1708647	0.14%	$1,795	$4,337,094	$0	$1,001,519	$1,795,983
1	1708690	0.88%	$1,746	$140,818	$0	$54,576	$79,312
1	1711166	0.14%	$383	$1,734,469	$8,000	$484,796	$628,161

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES ON ISSUE 2.2

Job #	Asset Identifier	Failure Probability	Direct Cost ($)	Indirect Cost ($)		PV (2015 Cost of Deviation from Optimal) ($)	2012 Cost of Deviation from Optimal ($)
				Customer Interruption Cost ($)	Other Indirect Cost ($)		
1	1711521	8.57%	$1,746	$24,688	$0	$14,841	$25,755
1	1712331	9.10%	$1,746	$140,818	$0	$0	$13,910
1	1712609	0.48%	$416	$4,032,737	$8,000	$718,793	$987,814
1	1713025	0.99%	$1,746	$140,818	$0	$52,471	$77,600
1	1750232	0.35%	$540	$0	$4,000	$2,388	$5,565
1	1750323	0.05%	$540	$0	$4,000	$6,323	$10,516
1	1750324	4.03%	$540	$0	$4,000	$8,750	$0
1	1750383	3.74%	$540	$0	$4,000	$8,698	$0
1	1750392	3.46%	$540	$0	$4,000	$6,991	$0
1	1750393	3.46%	$540	$0	$4,000	$6,991	$0
1	1750394	3.46%	$540	$0	$4,000	$6,991	$0
1	1750395	3.46%	$540	$0	$4,000	$6,991	$0
1	1750396	3.46%	$540	$0	$4,000	$6,991	$0
1	1750397	0.09%	$540	$0	$4,000	$5,487	$9,540
1	1750398	0.35%	$540	$0	$4,000	$1,157	$4,165
1	1750399	0.35%	$540	$0	$4,000	$1,157	$4,165
1	1750400	3.46%	$540	$0	$4,000	$13,757	$0
1	1750401	12.21%	$540	$0	$4,000	$12,864	$0
1	1750402	4.03%	$540	$0	$4,000	$2,158	$0
1	1750429	3.14%	$540	$0	$2,000	$6,016	$9,296
1	1750430	2.44%	$540	$0	$4,000	$7,999	$0
1	1750453	4.03%	$540	$0	$4,000	$2,158	$0
1	1750464	4.03%	$540	$0	$4,000	$16,657	$0
1	1750465	4.33%	$540	$0	$4,000	$2,223	$0
1	1750466	4.03%	$540	$0	$4,000	$1,844	$0
1	1750467	4.03%	$540	$0	$4,000	$1,844	$0

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES ON ISSUE 2.2

Job #	Asset Identifier	Failure Probability	Direct Cost ($)	Indirect Cost ($)		PV (2015 Cost of Deviation from Optimal) ($)	2012 Cost of Deviation from Optimal ($)
				Customer Interruption Cost ($)	Other Indirect Cost ($)		
1	1750468	4.03%	$540	$0	$4,000	$16,657	$0
1	1750469	4.03%	$540	$0	$4,000	$2,158	$0
1	1750470	4.03%	$540	$0	$4,000	$1,844	$0
1	1750474	1.60%	$540	$0	$4,000	$1,207	$2,925
1	1750482	1.86%	$540	$0	$4,000	$34,535	$48,274
1	1750483	1.60%	$540	$0	$4,000	$1,957	$4,090
1	1750485	4.03%	$540	$0	$4,000	$16,657	$0
1	1750493	4.33%	$540	$0	$4,000	$18,184	$0
1	7771333	0.00%	$383	$133,688	$8,000	$57,595	$68,852
1	7774903	0.00%	$383	$133,688	$8,000	$57,290	$68,553
1	28044440	0.00%	$383	$1,734,469	$8,000	$666,760	$817,052
1	28135725	0.01%	$383	$79,688	$8,000	$34,843	$41,995
1	28135727	0.03%	$383	$79,688	$8,000	$33,306	$40,656
1	28732105	0.00%	$383	$133,688	$8,000	$59,673	$71,529
1	28732401	0.00%	$383	$133,688	$8,000	$57,362	$68,615
1	28732408	0.00%	$383	$133,688	$8,000	$57,308	$68,568
1	28732413	0.00%	$383	$133,688	$8,000	$57,362	$68,615
1	28732414	0.05%	$383	$133,688	$8,000	$50,695	$62,510
1	28732490	0.03%	$383	$133,688	$8,000	$52,434	$64,087
1	28732493	0.00%	$383	$133,688	$8,000	$57,371	$68,623
1	28825900	0.08%	$383	$1,734,469	$8,000	$560,804	$702,341
1	28826000	0.11%	$383	$1,734,469	$8,000	$523,793	$666,333
1	28826002	0.12%	$383	$1,734,469	$8,000	$507,108	$650,035
1	28839006	0.03%	$383	$79,688	$8,000	$33,807	$41,090
1	30378202	0.03%	$383	$79,688	$8,000	$33,825	$41,105
2	13619217	0.02%	$383	$79,688	$8,000	$34,537	$41,550

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES ON ISSUE 2.2

Job #	Asset Identifier	Failure Probability	Direct Cost ($)	Indirect Cost ($)		PV (2015 Cost of Deviation from Optimal) ($)	2012 Cost of Deviation from Optimal ($)
				Customer Interruption Cost ($)	Other Indirect Cost ($)		
2	13619799	0.01%	$383	$56,250	$8,000	$25,603	$30,796
2	13622537	0.05%	$416	$6,647,691	$8,000	$2,275,716	$2,758,865
2	13625495	0.01%	$383	$56,250	$8,000	$25,618	$30,811
2	13626091	1.23%	$416	$6,647,691	$8,000	$371,118	$683,652
2	13626905	0.02%	$416	$6,647,691	$8,000	$2,371,886	$2,860,563
2	13628313	0.67%	$416	$6,647,691	$8,000	$917,722	$1,326,951
2	13629801	0.01%	$383	$56,250	$8,000	$25,621	$30,815
2	13630915	1.32%	$416	$6,647,691	$8,000	$314,989	$612,421
2	13631609	0.02%	$383	$79,688	$8,000	$34,541	$41,554
2	13636286	0.01%	$383	$56,250	$8,000	$25,628	$30,821
2	13636788	0.02%	$383	$56,250	$8,000	$25,584	$30,777
2	13637466	0.02%	$416	$6,647,691	$8,000	$2,372,905	$2,861,592
2	13638094	0.02%	$416	$6,647,691	$8,000	$2,373,584	$2,862,279
2	13639035	9.87%	$416	$6,647,691	$8,000	$1,345,110	$0
2	13640736	0.02%	$383	$79,688	$8,000	$34,544	$41,557
2	13640779	0.05%	$416	$6,647,691	$8,000	$2,266,218	$2,749,035
2	13640807	19.41%	$1,746	$83,938	$0	$14,100	$0
2	13644333	0.73%	$416	$6,647,691	$8,000	$796,816	$1,214,363
2	13645848	0.01%	$383	$56,250	$8,000	$25,692	$30,885
2	13646975	3.77%	$416	$6,647,691	$8,000	$150,152	$0
2	13647689	0.02%	$383	$56,250	$8,000	$25,571	$30,764
2	13649336	0.01%	$383	$56,250	$8,000	$25,613	$30,806
2	13651831	0.01%	$383	$79,688	$8,000	$34,577	$41,590
2	13652354	0.01%	$383	$56,250	$8,000	$25,609	$30,802
2	14068834	6.75%	$491	$0	$5,000	$1,343,617	$0
2	14069018	6.75%	$491	$0	$5,000	$1,343,617	$0

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Job #	Asset Identifier	Failure Probability	Direct Cost ($)	Indirect Cost ($)		PV (2015 Cost of Deviation from Optimal) ($)	2012 Cost of Deviation from Optimal ($)
				Customer Interruption Cost ($)	Other Indirect Cost ($)		
2	14082841	0.06%	$408	$0	$4,500	$4,632	$8,304
2	14082842	0.06%	$408	$0	$4,500	$4,632	$8,304
2	14082847	0.29%	$408	$0	$4,500	$0	$1,448
2	14082849	0.17%	$408	$0	$4,500	$1,049	$3,586
2	14082851	0.29%	$408	$0	$4,500	$0	$1,448
2	14082852	0.29%	$408	$0	$4,500	$0	$1,448
2	14082886	0.29%	$408	$0	$4,500	$0	$1,448
2	14131030	8.41%	$540	$0	$4,000	$14,881	$0
2	14131031	8.41%	$540	$0	$4,000	$15,664	$0
2	14131032	8.41%	$540	$0	$4,000	$21,945	$0
2	14131033	8.41%	$540	$0	$4,000	$21,945	$0
2	14131034	8.41%	$540	$0	$4,000	$21,945	$0
2	14131035	0.20%	$540	$0	$4,000	$3,866	$7,544
2	14131036	8.41%	$540	$0	$4,000	$21,945	$0
2	14131037	0.20%	$540	$0	$4,000	$3,866	$7,544
2	14131052	7.57%	$540	$0	$4,000	$13,859	$0
2	14131066	8.41%	$540	$0	$4,000	$21,945	$0
2	14131067	8.41%	$540	$0	$4,000	$15,664	$0
2	14131068	8.41%	$540	$0	$4,000	$15,664	$0
2	14131078	8.41%	$540	$0	$4,000	$15,664	$0
2	14131079	8.41%	$540	$0	$4,000	$15,664	$0
2	14131080	7.57%	$540	$0	$4,000	$13,859	$0
2	14131081	8.85%	$540	$0	$4,000	$24,092	$0
2	14131139	8.41%	$540	$0	$4,000	$14,881	$0
2	14131140	8.41%	$540	$0	$4,000	$15,664	$0
2	14131180	1.08%	$540	$0	$4,000	$30	$787

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Job #	Asset Identifier	Failure Probability	Direct Cost ($)	Indirect Cost ($)		PV (2015 Cost of Deviation from Optimal) ($)	2012 Cost of Deviation from Optimal ($)
				Customer Interruption Cost ($)	Other Indirect Cost ($)		
2	28649084	6.75%	$416	$0	$5,000	$1,551,597	$0
2	28779179	6.75%	$491	$0	$5,000	$1,343,617	$0
2	28779278	0.29%	$408	$0	$4,500	$0	$1,448
2	28779279	0.29%	$408	$0	$4,500	$0	$1,448
2	28784704	0.01%	$383	$79,688	$8,000	$34,560	$41,573
2	28784706	5.80%	$1,746	$83,938	$0	$1,725	$8,040
2	28784713	4.27%	$1,746	$83,938	$0	$5,465	$13,608
2	28784848	0.01%	$383	$79,688	$8,000	$34,553	$41,565
2	28784852	1.53%	$1,746	$83,938	$0	$24,749	$36,150
2	28784867	6.06%	$1,746	$83,938	$0	$1,465	$7,474
2	28785234	0.02%	$383	$79,688	$8,000	$34,548	$41,561
2	28785238	2.17%	$1,746	$83,938	$0	$17,586	$28,233
2	28785242	0.02%	$383	$79,688	$8,000	$34,520	$41,532
2	28785246	4.27%	$1,746	$83,938	$0	$5,467	$13,611
2	28785248	0.01%	$383	$79,688	$8,000	$34,559	$41,572
2	28785254	7.05%	$1,746	$83,938	$0	$0	$4,826
2	28785258	0.01%	$383	$79,688	$8,000	$34,578	$41,591
2	28785264	5.54%	$1,746	$83,938	$0	$1,989	$8,613
2	28785271	4.53%	$1,746	$83,938	$0	$4,491	$12,317
2	28785280	7.68%	$1,746	$59,250	$0	$1,575	$7,436
2	28785285	0.01%	$383	$56,250	$8,000	$25,591	$30,784
2	28785287	9.46%	$1,746	$59,250	$0	$579	$5,582
2	28785291	0.01%	$383	$56,250	$8,000	$25,654	$30,847
2	28785293	5.60%	$1,746	$59,250	$0	$3,937	$10,805
2	28785300	0.01%	$383	$56,250	$8,000	$25,680	$30,873
2	28785304	10.92%	$1,746	$59,250	$0	$0	$4,296

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Job #	Asset Identifier	Failure Probability	Direct Cost ($)	Indirect Cost ($)		PV (2015 Cost of Deviation from Optimal) ($)	2012 Cost of Deviation from Optimal ($)
				Customer Interruption Cost ($)	Other Indirect Cost ($)		
2	28785316	0.02%	$383	$56,250	$8,000	$25,573	$30,766
2	28785318	8.42%	$1,746	$59,250	$0	$826	$6,329
2	28785324	0.01%	$383	$56,250	$8,000	$25,607	$30,801
2	28785326	10.55%	$1,746	$59,250	$0	$0	$4,477
2	28785329	0.51%	$1,746	$59,250	$0	$34,286	$43,616
2	28785331	5.92%	$1,746	$59,250	$0	$3,562	$10,274
2	28785354	0.01%	$383	$56,250	$8,000	$25,679	$30,872
2	28785357	3.05%	$1,746	$59,250	$0	$10,733	$18,832
2	28785359	0.01%	$383	$56,250	$8,000	$25,598	$30,791
2	28785361	1.71%	$1,746	$59,250	$0	$18,595	$27,345
2	28785368	0.01%	$383	$56,250	$8,000	$25,643	$30,837
2	28785370	10.61%	$1,746	$59,250	$0	$0	$4,447
2	30325136	5.63%	$783	$0	$4,000	$10,934	$0
2	30325283	0.01%	$383	$79,688	$8,000	$34,704	$41,719
2	30476892	0.10%	$408	$0	$4,500	$2,199	$5,682
2	30476901	0.10%	$408	$0	$4,500	$2,199	$5,682
2	30476924	0.10%	$408	$0	$4,500	$2,199	$5,682
2	30476925	0.10%	$408	$0	$4,500	$2,199	$5,682
2	30477075	0.10%	$408	$0	$4,500	$2,199	$5,682
2	30477078	0.10%	$408	$0	$4,500	$2,199	$5,682
2	30477108	0.10%	$408	$0	$4,500	$2,199	$5,682
2	30477110	0.10%	$408	$0	$4,500	$2,199	$5,682
2	30477275	0.10%	$408	$0	$4,500	$2,199	$5,682
2	30477280	0.10%	$408	$0	$4,500	$2,199	$5,682
2	30477358	0.10%	$408	$0	$4,500	$2,199	$5,682
2	30477363	0.10%	$408	$0	$4,500	$2,199	$5,682

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES ON ISSUE 2.2

Job #	Asset Identifier	Failure Probability	Direct Cost ($)	Indirect Cost ($)		PV (2015 Cost of Deviation from Optimal) ($)	2012 Cost of Deviation from Optimal ($)
				Customer Interruption Cost ($)	Other Indirect Cost ($)		
2	30477386	0.06%	$408	$0	$4,500	$4,632	$8,304
2	30477387	0.06%	$408	$0	$4,500	$2,892	$7,288
2	30477400	0.06%	$408	$0	$4,500	$4,632	$8,304
2	30477405	0.06%	$408	$0	$4,500	$4,632	$8,304
2	30477480	0.10%	$408	$0	$4,500	$2,199	$5,682
2	30477482	0.10%	$408	$0	$4,500	$2,199	$5,682
2	30477512	0.10%	$408	$0	$4,500	$2,199	$5,682
2	30477514	0.10%	$408	$0	$4,500	$2,199	$5,682
2	30477528	0.06%	$408	$0	$4,500	$4,632	$8,304
2	30477531	0.06%	$408	$0	$4,500	$4,632	$8,304
2	30477574	0.06%	$408	$0	$4,500	$4,632	$8,304
2	30477578	0.06%	$408	$0	$4,500	$4,632	$8,304
2	30477589	0.06%	$408	$0	$4,500	$4,632	$8,304
2	30477590	0.06%	$408	$0	$4,500	$4,632	$8,304
2	30477601	0.06%	$408	$0	$4,500	$4,632	$8,304
2	30477602	0.06%	$408	$0	$4,500	$4,632	$8,304
2	30477607	0.06%	$408	$0	$4,500	$4,632	$8,304
2	30477608	0.06%	$408	$0	$4,500	$4,632	$8,304
2	30477671	0.06%	$408	$0	$4,500	$4,632	$8,304
2	30477674	0.06%	$408	$0	$4,500	$4,632	$8,304
2	30477758	2.45%	$441	$0	$4,500	$499,793	$0
2	30477759	2.45%	$441	$0	$4,500	$499,793	$0
2	30477906	2.45%	$441	$0	$4,500	$499,793	$0
2	30477910	2.45%	$441	$0	$4,500	$499,793	$0
2	30477924	2.45%	$441	$0	$4,500	$499,793	$0
2	30477926	2.45%	$441	$0	$4,500	$499,793	$0

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES ON ISSUE 2.2

Job #	Asset Identifier	Failure Probability	Direct Cost ($)	Indirect Cost ($)		PV (2015 Cost of Deviation from Optimal) ($)	2012 Cost of Deviation from Optimal ($)
				Customer Interruption Cost ($)	Other Indirect Cost ($)		
2	30477955	0.29%	$408	$0	$4,500	$0	$1,448
2	30477956	0.29%	$408	$0	$4,500	$0	$1,448
2	30478071	0.29%	$408	$0	$4,500	$0	$1,448
2	30478072	0.29%	$408	$0	$4,500	$0	$1,448
2	30478110	1.48%	$408	$0	$4,500	$13,099	$0
2	30478119	1.48%	$408	$0	$4,500	$13,099	$0
2	30478122	1.48%	$408	$0	$4,500	$13,099	$0
2	30478351	0.00%	$416	$6,647,691	$8,000	$2,488,130	$3,038,170
2	30478893	0.17%	$408	$0	$4,500	$1,049	$3,586
2	30478894	0.17%	$408	$0	$4,500	$1,049	$3,586
2	30478899	0.17%	$408	$0	$4,500	$1,049	$3,586
2	30478900	0.17%	$408	$0	$4,500	$1,049	$3,586
2	30478902	0.17%	$408	$0	$4,500	$1,049	$3,586
2	30478903	0.17%	$408	$0	$4,500	$1,049	$3,586
2	30484418	0.29%	$408	$0	$4,500	$1,460	$0
3	1175900	0.14%	$218	$125,792	$385	$6,823	$9,714
3	1669307	0.00%	$214	$2,343,469	$8,000	$1,342,102	$1,603,970
3	1674198	0.00%	$214	$2,343,469	$8,000	$1,325,324	$1,590,156
3	1679031	0.05%	$383	$110,156	$8,000	$42,457	$52,335
3	1680302	1.96%	$1,746	$116,031	$0	$37,774	$62,006
3	1680547	0.89%	$1,746	$116,031	$0	$47,755	$68,568
3	1680949	0.76%	$1,746	$116,031	$0	$49,935	$70,339
3	1681128	0.04%	$720	$82,500	$8,000	$21,573	$26,755
3	1683081	0.02%	$720	$123,750	$8,000	$32,109	$39,168
3	1683407	0.00%	$383	$110,156	$8,000	$47,746	$57,159
3	1684471	0.00%	$383	$110,156	$8,000	$47,757	$57,169

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES ON ISSUE 2.2

Job #	Asset Identifier	Failure Probability	Direct Cost ($)	Indirect Cost ($)		PV (2015 Cost of Deviation from Optimal) ($)	2012 Cost of Deviation from Optimal ($)
				Customer Interruption Cost ($)	Other Indirect Cost ($)		
3	1685044	1.98%	$2,233	$99,000	$0	$20,600	$36,679
3	1689261	1.62%	$2,233	$99,000	$0	$20,716	$35,500
3	1691261	0.01%	$383	$110,156	$8,000	$49,754	$59,769
3	1691855	0.11%	$383	$110,156	$8,000	$38,901	$49,155
3	1692354	0.03%	$383	$110,156	$8,000	$44,900	$54,556
3	1693752	0.03%	$383	$110,156	$8,000	$44,360	$54,063
3	1695007	1.93%	$2,233	$99,000	$0	$20,560	$36,472
3	1695087	0.76%	$1,746	$116,031	$0	$49,935	$70,339
3	1696214	1.53%	$1,746	$116,031	$0	$40,571	$63,426
3	1697109	0.00%	$383	$110,156	$8,000	$47,742	$57,155
3	1698308	1.00%	$1,746	$116,031	$0	$46,155	$67,310
3	1700380	0.31%	$2,233	$99,000	$0	$53,545	$74,338
3	1700519	0.00%	$383	$110,156	$8,000	$47,756	$57,168
3	1700949	2.69%	$1,746	$116,031	$0	$34,929	$61,467
3	1700953	0.04%	$720	$82,500	$8,000	$21,685	$26,852
3	1702545	0.00%	$383	$110,156	$8,000	$47,754	$57,167
3	1703762	1.37%	$1,746	$116,031	$0	$41,931	$64,277
3	1705125	0.00%	$383	$110,156	$8,000	$47,744	$57,157
3	1705349	0.06%	$383	$110,156	$8,000	$42,087	$52,001
3	1705612	1.87%	$2,233	$99,000	$0	$20,503	$36,185
3	1705968	1.92%	$2,233	$99,000	$0	$20,550	$36,421
3	1706138	0.03%	$383	$110,156	$8,000	$44,541	$54,228
3	1707462	0.26%	$1,746	$116,031	$0	$66,762	$85,548
3	1708360	1.40%	$2,233	$99,000	$0	$20,979	$34,962
3	1708978	0.03%	$720	$82,500	$8,000	$22,275	$27,367
3	1709274	7.85%	$1,746	$116,031	$0	$32,464	$75,428

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES ON ISSUE 2.2

Job #	Asset Identifier	Failure Probability	Direct Cost ($)	Indirect Cost ($)		PV (2015 Cost of Deviation from Optimal) ($)	2012 Cost of Deviation from Optimal ($)
				Customer Interruption Cost ($)	Other Indirect Cost ($)		
3	1711401	0.03%	$720	$82,500	$8,000	$22,441	$27,513
3	1711989	5.26%	$2,233	$148,500	$0	$11,098	$35,701
3	1712816	0.04%	$383	$110,156	$8,000	$43,793	$53,547
3	1742148	2.44%	$540	$0	$4,000	$1,500	$0
3	1742149	1.79%	$540	$0	$4,000	$243	$220
3	1742150	2.44%	$540	$0	$4,000	$1,500	$0
3	1742151	3.18%	$540	$0	$4,000	$9,647	$0
3	1742152	1.42%	$540	$0	$4,000	$3,010	$0
3	1742153	1.42%	$540	$0	$4,000	$2,098	$0
3	1744632	2.00%	$540	$0	$4,000	$1,355	$0
3	1744634	1.42%	$540	$0	$4,000	$216	$198
3	1744801	2.44%	$540	$0	$4,000	$6,494	$0
3	1744818	1.42%	$540	$0	$4,000	$3,010	$0
3	1744819	1.42%	$540	$0	$4,000	$3,010	$0
3	1744820	1.42%	$540	$0	$4,000	$2,098	$0
3	1744821	1.42%	$540	$0	$4,000	$3,010	$0
3	1744858	1.42%	$540	$0	$4,000	$2,098	$0
3	1744859	1.42%	$540	$0	$4,000	$2,098	$0
3	1744864	1.79%	$540	$0	$4,000	$3,728	$0
3	30535608	2.14%	$2,233	$148,500	$0	$15,884	$33,541
4	815836	1.83%	$408	$0	$4,500	$59,279	$0
4	815837	1.83%	$408	$0	$4,500	$43,123	$0
4	815854	1.83%	$408	$0	$4,500	$43,123	$0
4	815855	1.83%	$408	$0	$4,500	$43,123	$0
4	816196	0.81%	$2,296	$868,803	$0	$657,740	$807,793
4	817414	4.71%	$383	$824,813	$8,000	$25,744	$0

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES ON ISSUE 2.2

Job #	Asset Identifier	Failure Probability	Direct Cost ($)	Indirect Cost ($)		PV (2015 Cost of Deviation from Optimal) ($)	2012 Cost of Deviation from Optimal ($)
				Customer Interruption Cost ($)	Other Indirect Cost ($)		
4	817510	0.21%	$383	$824,813	$8,000	$257,883	$320,174
4	818617	0.06%	$383	$824,813	$8,000	$323,004	$390,314
4	818794	1.70%	$2,296	$868,803	$0	$662,568	$830,316
4	818807	1.89%	$720	$157,500	$8,000	$244	$2,358
4	818929	0.48%	$720	$157,500	$8,000	$19,897	$27,311
4	819300	2.11%	$720	$45,000	$8,000	$301	$1,409
4	824084	11.16%	$540	$0	$4,000	$1,134	$0
4	824105	11.16%	$540	$0	$4,000	$12,110	$0
4	824106	11.16%	$540	$0	$4,000	$20,808	$0
4	824107	11.16%	$540	$0	$4,000	$1,134	$0
4	824111	11.16%	$540	$0	$4,000	$2,293	$0
4	906184	0.07%	$383	$824,813	$8,000	$297,124	$361,355
4	28080180	0.14%	$720	$149,850	$8,000	$34,332	$42,543
4	28080191	0.05%	$720	$202,500	$8,000	$48,545	$59,017
4	28080193	0.05%	$720	$202,500	$8,000	$48,299	$58,757
4	28080194	0.05%	$720	$202,500	$8,000	$48,140	$58,589
4	28080196	0.05%	$720	$202,500	$8,000	$47,953	$58,392
4	28080197	0.04%	$720	$202,500	$8,000	$48,856	$59,347
4	28080198	0.03%	$720	$202,500	$8,000	$50,113	$60,675
4	28080199	0.05%	$720	$202,500	$8,000	$48,226	$58,681
4	28080242	0.07%	$383	$824,813	$8,000	$297,250	$361,488
4	28080243	0.08%	$383	$824,813	$8,000	$297,528	$361,938
4	28080386	0.14%	$720	$202,500	$8,000	$41,304	$51,361
4	28080387	0.18%	$720	$202,500	$8,000	$38,150	$48,027
4	28080388	0.28%	$720	$202,500	$8,000	$31,854	$41,316
4	28080393	5.30%	$580	$0	$2,800	$227	$0

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES ON ISSUE 2.2

Job #	Asset Identifier	Failure Probability	Direct Cost ($)	Indirect Cost ($)		PV (2015 Cost of Deviation from Optimal) ($)	2012 Cost of Deviation from Optimal ($)
				Customer Interruption Cost ($)	Other Indirect Cost ($)		
4	28080397	0.08%	$720	$202,500	$8,000	$45,849	$56,166
4	28080398	0.15%	$720	$202,500	$8,000	$40,619	$50,637
4	28080399	0.16%	$720	$202,500	$8,000	$39,771	$49,740
4	28080400	0.06%	$416	$0	$8,000	$3,910	$4,739
4	28080401	0.24%	$720	$202,500	$8,000	$34,142	$43,767
4	28080402	0.14%	$720	$202,500	$8,000	$41,595	$51,669
4	28080404	0.03%	$720	$0	$8,000	$3,928	$4,750
4	28080405	0.03%	$720	$0	$8,000	$3,936	$4,755
4	28080406	0.03%	$720	$45,000	$8,000	$14,038	$17,016
4	28080416	0.09%	$720	$157,500	$8,000	$38,455	$47,165
4	28080419	0.07%	$720	$157,500	$8,000	$39,655	$48,432
4	28080421	0.04%	$720	$0	$8,000	$3,926	$4,748
4	28080453	0.25%	$383	$824,813	$8,000	$248,900	$310,710
4	28080457	1.99%	$720	$157,500	$8,000	$0	$1,715
4	28080506	0.09%	$720	$832,350	$8,000	$177,089	$217,327
4	28080516	0.04%	$720	$832,350	$8,000	$190,574	$231,246
4	28080517	0.04%	$720	$832,350	$8,000	$187,680	$228,176
4	28080518	0.05%	$720	$832,350	$8,000	$187,610	$228,101
4	28080519	0.04%	$720	$832,350	$8,000	$190,574	$231,246
4	28080520	0.04%	$720	$832,350	$8,000	$187,807	$228,311
4	28080521	0.04%	$720	$832,350	$8,000	$187,850	$228,356
4	28080522	0.09%	$720	$832,350	$8,000	$175,129	$215,240
4	28080523	0.14%	$720	$832,350	$8,000	$162,635	$201,987
4	28080524	0.12%	$720	$832,350	$8,000	$166,870	$206,480
4	28080534	0.04%	$720	$269,850	$8,000	$64,174	$77,897
4	28080535	0.05%	$720	$269,850	$8,000	$63,179	$76,844

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES ON ISSUE 2.2

Job #	Asset Identifier	Failure Probability	Direct Cost ($)	Indirect Cost ($)		PV (2015 Cost of Deviation from Optimal) ($)	2012 Cost of Deviation from Optimal ($)
				Customer Interruption Cost ($)	Other Indirect Cost ($)		
4	28080536	0.05%	$720	$269,850	$8,000	$63,276	$76,947
4	28080540	0.04%	$720	$112,500	$8,000	$28,964	$35,158
4	28080542	0.05%	$720	$0	$8,000	$3,885	$4,704
4	28080544	0.05%	$720	$0	$8,000	$3,884	$4,703
4	28080546	0.04%	$720	$269,850	$8,000	$64,271	$78,000
4	28080547	0.03%	$720	$269,850	$8,000	$64,923	$78,691
4	28080548	9.54%	$745	$0	$4,500	$72,176	$0
4	28080549	0.03%	$720	$269,850	$8,000	$64,812	$78,574
4	28080550	9.54%	$745	$0	$4,500	$72,176	$0
4	28080568	11.16%	$540	$0	$4,000	$4,815	$0
4	28080569	11.16%	$540	$0	$4,000	$35,500	$0
4	28080571	0.23%	$720	$269,850	$8,000	$47,883	$61,008
4	28080572	0.21%	$720	$269,850	$8,000	$49,750	$62,996
4	28080576	11.16%	$540	$0	$4,000	$4,815	$0
4	28080578	0.53%	$720	$269,850	$8,000	$26,926	$38,147
4	28080581	11.16%	$540	$0	$4,000	$15,056	$0
4	28080582	11.16%	$540	$0	$4,000	$4,815	$0
4	28080583	1.59%	$720	$112,500	$8,000	$1,322	$3,951
4	28080584	0.39%	$720	$112,500	$8,000	$18,003	$23,886
4	28080585	0.12%	$720	$112,500	$8,000	$28,266	$34,813
4	28080672	0.54%	$720	$269,850	$8,000	$26,626	$37,808
4	28080700	0.05%	$720	$157,500	$8,000	$38,641	$46,970
4	28080702	0.15%	$720	$157,500	$8,000	$35,253	$43,784
4	28080703	0.05%	$720	$157,500	$8,000	$38,301	$46,611
4	28080705	0.05%	$720	$157,500	$8,000	$38,446	$46,765
4	28080706	0.05%	$720	$157,500	$8,000	$38,401	$46,716

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES ON ISSUE 2.2

Job #	Asset Identifier	Failure Probability	Direct Cost ($)	Indirect Cost ($)		PV (2015 Cost of Deviation from Optimal) ($)	2012 Cost of Deviation from Optimal ($)
				Customer Interruption Cost ($)	Other Indirect Cost ($)		
4	28080708	0.05%	$720	$157,500	$8,000	$38,430	$46,748
4	28080709	0.08%	$720	$157,500	$8,000	$36,660	$44,879
4	28080711	0.15%	$720	$157,500	$8,000	$32,597	$40,587
4	28080712	0.24%	$720	$157,500	$8,000	$27,620	$35,317
4	28080714	0.24%	$720	$157,500	$8,000	$27,643	$35,341
4	28080716	0.15%	$720	$157,500	$8,000	$32,821	$40,824
4	28080717	0.52%	$720	$157,500	$8,000	$18,337	$25,586
4	28080719	0.09%	$720	$157,500	$8,000	$38,820	$47,550
4	28080720	0.07%	$720	$157,500	$8,000	$36,958	$45,192
4	28080721	0.16%	$720	$157,500	$8,000	$31,732	$39,674
4	28080722	0.16%	$720	$157,500	$8,000	$31,670	$39,608
5	13619007	0.01%	$383	$567,188	$8,000	$224,483	$269,530
5	13619316	27.53%	$1,746	$597,438	$0	$404,287	$0
5	13619780	7.16%	$1,746	$54,313	$0	$8,622	$20,328
5	13620529	0.01%	$720	$150,000	$8,000	$40,272	$48,388
5	13623640	2.68%	$1,746	$597,438	$0	$39,442	$88,571
5	13624002	0.24%	$1,746	$34,563	$0	$26,025	$32,177
5	13626002	0.01%	$383	$567,188	$8,000	$223,722	$268,785
5	13626341	52.85%	$1,746	$597,438	$0	$860,566	$0
5	13626792	0.04%	$383	$567,188	$8,000	$218,475	$264,243
5	13627067	36.50%	$1,746	$597,438	$0	$565,859	$0
5	13627517	0.01%	$383	$567,188	$8,000	$224,668	$269,631
5	13629206	0.01%	$383	$567,188	$8,000	$224,886	$269,851
5	13630733	0.01%	$720	$150,000	$8,000	$40,611	$48,816
5	13630920	0.01%	$383	$567,188	$8,000	$225,215	$270,246
5	13631056	0.02%	$383	$84,375	$8,000	$36,251	$43,626

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES ON ISSUE 2.2

Job #	Asset Identifier	Failure Probability	Direct Cost ($)	Indirect Cost ($)		PV (2015 Cost of Deviation from Optimal) ($)	2012 Cost of Deviation from Optimal ($)
				Customer Interruption Cost ($)	Other Indirect Cost ($)		
5	13633256	47.68%	$1,746	$597,438	$0	$767,359	$0
5	13633538	0.01%	$383	$567,188	$8,000	$223,776	$268,838
5	13634162	0.07%	$383	$42,188	$8,000	$18,991	$23,169
5	13635701	0.06%	$383	$567,188	$8,000	$210,381	$256,319
5	13635893	2.37%	$1,746	$113,563	$0	$19,571	$34,081
5	13635894	3.33%	$1,746	$113,563	$0	$11,766	$25,027
5	13638184	1.17%	$1,746	$34,563	$0	$19,308	$26,366
5	13638256	4.20%	$1,746	$88,875	$0	$9,038	$20,489
5	13639087	0.03%	$383	$567,188	$8,000	$220,244	$265,975
5	13639803	0.01%	$720	$150,000	$8,000	$40,289	$48,405
5	13640243	0.23%	$1,746	$34,563	$0	$26,099	$32,247
5	13641699	0.86%	$1,746	$54,313	$0	$138,855	$171,972
5	13642825	0.88%	$1,746	$597,438	$0	$193,731	$269,693
5	13643722	0.03%	$383	$567,188	$8,000	$220,558	$266,282
5	13645186	0.03%	$383	$567,188	$8,000	$216,678	$261,889
5	13645558	2.08%	$1,746	$597,438	$0	$69,951	$127,954
5	13646175	2.88%	$1,746	$597,438	$0	$31,631	$77,808
5	13647062	0.01%	$383	$567,188	$8,000	$224,065	$269,120
5	13648552	2.09%	$1,746	$597,438	$0	$69,665	$127,593
5	13649857	0.02%	$383	$107,813	$8,000	$45,191	$54,412
5	13650005	4.22%	$1,746	$597,438	$0	$0	$21,776
5	13650434	0.23%	$1,746	$69,125	$0	$46,098	$57,127
5	13650636	0.02%	$383	$567,188	$8,000	$222,417	$267,507
5	13650716	0.92%	$1,746	$597,438	$0	$188,787	$264,261
5	13651250	0.03%	$383	$567,188	$8,000	$216,732	$261,942
5	13652918	17.57%	$1,746	$597,438	$0	$225,080	$0

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES ON ISSUE 2.2

Job #	Asset Identifier	Failure Probability	Direct Cost ($)	Indirect Cost ($)		PV (2015 Cost of Deviation from Optimal) ($)	2012 Cost of Deviation from Optimal ($)
				Customer Interruption Cost ($)	Other Indirect Cost ($)		
5	13653669	72.12%	$1,746	$597,438	$0	$1,208,074	$0
5	13653728	0.00%	$720	$847,500	$8,000	$209,568	$262,177
5	14066746	8.63%	$458	$0	$5,000	$117,798	$0
5	14066748	10.69%	$795	$0	$5,000	$23,378	$0
5	14066886	8.63%	$458	$0	$5,000	$117,798	$0
5	14066887	8.63%	$458	$0	$5,000	$117,798	$0
5	14066888	8.63%	$458	$0	$5,000	$117,798	$0
5	14080282	3.18%	$408	$0	$4,500	$51,466	$0
5	14080283	2.02%	$408	$0	$4,500	$31,998	$0
5	14080284	3.18%	$408	$0	$4,500	$51,466	$0
5	14080287	2.02%	$408	$0	$4,500	$31,998	$0
5	14126563	4.47%	$540	$0	$4,000	$4,279	$10,658
5	14126622	2.91%	$540	$0	$4,000	$19,380	$27,923
5	26483918	0.91%	$383	$567,188	$8,000	$64,746	$102,715
5	26483976	0.62%	$720	$847,500	$8,000	$54,276	$88,610
5	26486792	0.24%	$450	$4,153,590	$8,000	$949,700	$1,231,227
5	26486924	9.29%	$525	$0	$5,000	$1,124,850	$0
5	26486943	0.82%	$795	$0	$5,000	$1,822	$17,149
5	26488781	0.91%	$720	$847,500	$8,000	$28,110	$57,074
5	26489202	0.17%	$720	$150,000	$8,000	$27,743	$35,820
5	28145344	0.06%	$383	$65,625	$8,000	$27,398	$33,382
5	28145349	0.11%	$383	$65,625	$8,000	$25,501	$31,528
5	28160710	0.13%	$383	$65,625	$8,000	$24,969	$31,009
5	28160713	0.01%	$383	$65,625	$8,000	$29,609	$35,541
5	28743214	0.14%	$383	$51,563	$8,000	$19,509	$24,323
5	28757269	0.11%	$383	$51,563	$8,000	$20,499	$25,318

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES ON ISSUE 2.2

Job #	Asset Identifier	Failure Probability	Direct Cost ($)	Indirect Cost ($)		PV (2015 Cost of Deviation from Optimal) ($)	2012 Cost of Deviation from Optimal ($)
				Customer Interruption Cost ($)	Other Indirect Cost ($)		
5	28757851	0.00%	$383	$32,813	$8,000	$18,386	$22,135
5	28757909	0.00%	$383	$37,500	$8,000	$20,157	$24,256
5	28758621	0.00%	$383	$42,188	$8,000	$22,523	$27,197
5	28818127	2.11%	$1,746	$44,438	$0	$17,419	$26,245
5	28818157	0.09%	$383	$42,188	$8,000	$18,420	$22,625
5	28818161	0.24%	$383	$42,188	$8,000	$14,595	$18,686
5	28818165	0.13%	$383	$42,188	$8,000	$17,518	$21,766
5	28818171	0.24%	$383	$42,188	$8,000	$14,493	$18,584
5	28818179	0.45%	$383	$42,188	$8,000	$11,389	$15,431
5	28818186	0.21%	$383	$42,188	$8,000	$15,146	$19,242
5	28818192	0.43%	$383	$51,563	$8,000	$13,406	$18,118
5	28818196	0.31%	$383	$51,563	$8,000	$15,575	$20,341
5	28818201	0.06%	$383	$51,563	$8,000	$22,409	$27,307
5	28818206	0.09%	$383	$51,563	$8,000	$21,778	$26,697
5	28818212	0.12%	$383	$51,563	$8,000	$20,172	$24,989
5	28818217	5.58%	$1,746	$54,313	$0	$10,366	$21,439
5	28818222	0.30%	$383	$51,563	$8,000	$15,721	$20,490
5	28818227	3.40%	$1,746	$54,313	$0	$13,831	$24,036
5	28818522	8.31%	$1,746	$69,125	$0	$4,394	$15,205
5	28818524	5.64%	$1,746	$69,125	$0	$7,564	$18,447
5	28818534	10.38%	$1,746	$69,125	$0	$2,890	$13,646
5	28818539	3.99%	$1,746	$69,125	$0	$10,964	$21,892
5	28818545	6.00%	$1,746	$69,125	$0	$7,113	$17,986
5	28818551	5.36%	$1,746	$69,125	$0	$7,910	$18,801
5	28818556	2.76%	$1,746	$69,125	$0	$15,320	$26,281
5	28818561	1.66%	$1,746	$69,125	$0	$22,175	$33,166

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES ON ISSUE 2.2

Job #	Asset Identifier	Failure Probability	Direct Cost ($)	Indirect Cost ($)		PV (2015 Cost of Deviation from Optimal) ($)	2012 Cost of Deviation from Optimal ($)
				Customer Interruption Cost ($)	Other Indirect Cost ($)		
5	28818567	22.88%	$1,746	$69,125	$0	$0	$10,419
5	28818579	7.27%	$1,746	$113,563	$0	$874	$8,984
5	28818585	5.08%	$1,746	$113,563	$0	$4,558	$15,530
5	28818590	0.68%	$383	$107,813	$8,000	$17,858	$26,139
5	28818594	0.30%	$383	$107,813	$8,000	$29,018	$37,921
5	28818598	0.13%	$383	$107,813	$8,000	$37,308	$46,410
5	28818603	0.33%	$383	$107,813	$8,000	$27,781	$36,639
5	28818608	0.13%	$383	$107,813	$8,000	$37,285	$46,387
5	28818613	0.44%	$383	$107,813	$8,000	$24,129	$32,825
5	28818617	0.08%	$383	$107,813	$8,000	$41,192	$50,448
5	28818622	4.67%	$1,746	$113,563	$0	$5,970	$17,475
5	28818626	9.03%	$1,746	$113,563	$0	$188	$4,965
5	28819724	7.63%	$1,746	$113,563	$0	$0	$7,643
5	28820061	3.47%	$1,746	$34,563	$0	$16,012	$25,301
5	28820079	4.63%	$1,746	$34,563	$0	$15,762	$26,169
5	28820088	3.37%	$1,746	$34,563	$0	$16,024	$25,207
5	28820097	5.97%	$1,746	$34,563	$0	$15,973	$27,682
5	28820103	3.25%	$1,746	$34,563	$0	$16,162	$25,229
5	28820111	6.07%	$1,746	$34,563	$0	$16,009	$27,810
5	28820116	4.01%	$1,746	$34,563	$0	$15,853	$25,660
5	28820121	13.25%	$1,746	$34,563	$0	$18,952	$37,711
5	28820127	3.72%	$1,746	$34,563	$0	$15,984	$25,511
5	28820132	2.42%	$1,746	$34,563	$0	$16,749	$25,020
5	28820136	8.86%	$1,746	$34,563	$0	$17,090	$31,594
5	28820141	6.18%	$1,746	$34,563	$0	$16,054	$27,965
5	28820148	3.94%	$1,746	$34,563	$0	$15,848	$25,589

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES ON ISSUE 2.2

Job #	Asset Identifier	Failure Probability	Direct Cost ($)	Indirect Cost ($)		PV (2015 Cost of Deviation from Optimal) ($)	2012 Cost of Deviation from Optimal ($)
				Customer Interruption Cost ($)	Other Indirect Cost ($)		
5	28820159	2.48%	$1,746	$34,563	$0	$16,706	$25,029
5	28821163	5.00%	$1,746	$54,313	$0	$10,891	$21,734
5	28821167	6.60%	$1,746	$54,313	$0	$9,336	$20,817
5	28821173	4.05%	$1,746	$54,313	$0	$12,540	$23,004
5	28821179	5.91%	$1,746	$54,313	$0	$9,783	$20,989
5	28821183	2.22%	$1,746	$54,313	$0	$17,512	$27,245
5	28821188	7.22%	$1,746	$54,313	$0	$8,598	$20,326
5	28821192	3.07%	$1,746	$54,313	$0	$14,686	$24,759
5	28821196	6.47%	$1,746	$54,313	$0	$9,417	$20,848
5	28821201	6.51%	$1,746	$54,313	$0	$9,392	$20,838
5	28821215	4.99%	$1,746	$54,313	$0	$10,902	$21,741
5	28821217	3.28%	$1,746	$88,875	$0	$12,758	$24,758
5	28821221	2.01%	$1,746	$88,875	$0	$21,339	$34,100
5	28821226	4.45%	$1,746	$88,875	$0	$8,056	$19,360
5	28821232	10.48%	$1,746	$88,875	$0	$0	$7,716
5	28821236	0.34%	$383	$84,375	$8,000	$22,168	$29,305
5	28821240	0.11%	$383	$84,375	$8,000	$31,557	$39,025
5	28821245	0.01%	$383	$84,375	$8,000	$36,537	$43,933
5	28821251	0.09%	$383	$84,375	$8,000	$32,151	$39,490
5	28821255	0.21%	$383	$84,375	$8,000	$26,575	$33,834
5	28821260	2.28%	$1,746	$88,875	$0	$18,920	$31,520
5	28821264	22.39%	$1,746	$88,875	$0	$5,543	$2,160
5	28821269	3.99%	$1,746	$88,875	$0	$9,681	$21,262
5	28821671	3.20%	$1,746	$54,313	$0	$14,227	$24,350
5	28821675	0.12%	$1,746	$54,313	$0	$57,683	$69,899
5	28821679	0.13%	$383	$51,563	$8,000	$20,623	$25,583

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES ON ISSUE 2.2

Job #	Asset Identifier	Failure Probability	Direct Cost ($)	Indirect Cost ($)		PV (2015 Cost of Deviation from Optimal) ($)	2012 Cost of Deviation from Optimal ($)
				Customer Interruption Cost ($)	Other Indirect Cost ($)		
5	28821683	0.11%	$383	$51,563	$8,000	$21,143	$26,084
5	28821688	0.07%	$383	$51,563	$8,000	$21,926	$26,779
5	28821718	6.36%	$1,746	$54,313	$0	$9,487	$20,875
5	28821723	5.31%	$1,746	$54,313	$0	$10,610	$21,576
5	28821727	0.03%	$383	$51,563	$8,000	$23,340	$28,205
5	28821731	0.08%	$383	$51,563	$8,000	$21,921	$26,836
5	28821735	6.44%	$1,746	$54,313	$0	$9,437	$20,855
5	28821739	3.97%	$1,746	$54,313	$0	$12,661	$23,095
5	28821742	3.78%	$1,746	$44,438	$0	$14,297	$24,269
5	28821746	4.10%	$1,746	$44,438	$0	$13,867	$24,056
5	28821750	9.18%	$1,746	$44,438	$0	$11,475	$25,136
5	28821754	2.38%	$1,746	$44,438	$0	$16,697	$25,707
5	28821758	3.55%	$1,746	$44,438	$0	$14,537	$24,351
5	28821762	5.84%	$1,746	$44,438	$0	$12,538	$23,916
5	28821766	0.37%	$383	$42,188	$8,000	$14,140	$18,588
5	28821771	0.11%	$383	$42,188	$8,000	$18,010	$22,234
5	30331972	0.28%	$1,746	$69,125	$0	$44,323	$55,350
5	30332024	0.23%	$1,746	$113,563	$0	$71,724	$89,026
5	30332528	0.24%	$1,746	$113,563	$0	$71,570	$88,869
5	30332565	0.01%	$383	$107,813	$8,000	$46,087	$55,300
5	30332605	0.02%	$383	$107,813	$8,000	$45,363	$54,560
5	30332616	0.02%	$383	$107,813	$8,000	$45,308	$54,504
5	30332967	0.23%	$1,746	$88,875	$0	$57,578	$71,397
5	30333111	0.02%	$383	$42,188	$8,000	$20,227	$24,326
5	30333221	0.29%	$1,746	$34,563	$0	$25,332	$31,533
5	30333365	0.32%	$1,746	$88,875	$0	$53,433	$67,198

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES ON ISSUE 2.2

Job #	Asset Identifier	Failure Probability	Direct Cost ($)	Indirect Cost ($)		PV (2015 Cost of Deviation from Optimal) ($)	2012 Cost of Deviation from Optimal ($)
				Customer Interruption Cost ($)	Other Indirect Cost ($)		
5	30333861	0.01%	$383	$42,188	$8,000	$20,513	$24,621
5	30333931	0.23%	$1,746	$69,125	$0	$46,229	$57,258
5	30334103	0.01%	$383	$65,625	$8,000	$29,613	$35,545
5	30334671	0.13%	$383	$42,188	$8,000	$17,645	$21,886
5	30334685	0.01%	$383	$65,625	$8,000	$29,582	$35,515
5	30335978	0.24%	$1,746	$69,125	$0	$45,946	$56,974
5	30337394	0.31%	$1,746	$54,313	$0	$35,513	$44,482
5	30337798	0.24%	$1,746	$54,313	$0	$37,324	$46,264
5	30337915	0.26%	$1,746	$54,313	$0	$36,799	$45,747
5	30338129	0.28%	$1,746	$44,438	$0	$30,874	$38,449
5	30338142	0.25%	$1,746	$54,313	$0	$37,095	$46,038
5	30338282	0.28%	$1,746	$44,438	$0	$30,841	$38,416
5	30338292	0.25%	$1,746	$44,438	$0	$31,473	$39,026
5	30338324	0.26%	$1,746	$44,438	$0	$31,142	$38,707
5	30338388	0.25%	$1,746	$34,563	$0	$25,826	$31,992
5	30338485	0.24%	$1,746	$34,563	$0	$25,930	$32,088
5	30338761	0.25%	$1,746	$54,313	$0	$36,938	$45,884
5	30338944	0.25%	$1,746	$54,313	$0	$37,142	$46,085
5	30339026	0.28%	$1,746	$34,563	$0	$25,430	$31,624
5	30391419	0.26%	$1,746	$88,875	$0	$56,164	$69,965
5	30391421	0.23%	$1,746	$88,875	$0	$57,696	$71,516
5	30391484	0.26%	$1,746	$34,563	$0	$25,706	$31,880
5	30410375	0.01%	$383	$65,625	$8,000	$29,626	$35,557
5	30609615	0.00%	$383	$567,188	$8,000	$232,201	$277,290
5	30609616	0.00%	$383	$567,188	$8,000	$232,200	$277,294
5	30609617	0.01%	$383	$567,188	$8,000	$224,588	$269,632

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES ON ISSUE 2.2

Job #	Asset Identifier	Failure Probability	Direct Cost ($)	Indirect Cost ($)		PV (2015 Cost of Deviation from Optimal) ($)	2012 Cost of Deviation from Optimal ($)
				Customer Interruption Cost ($)	Other Indirect Cost ($)		
6	13618509	0.28%	$2,233	$81,000	$0	$25,284	$32,562
6	13618717	0.35%	$2,233	$81,000	$0	$23,308	$30,558
6	13619148	0.77%	$720	$75,150	$8,000	$8,097	$12,193
6	13619369	0.04%	$383	$309,375	$8,000	$121,218	$146,621
6	13619977	0.36%	$1,746	$34,563	$0	$24,404	$30,679
6	13620242	4.26%	$1,746	$19,750	$0	$8,000	$12,702
6	13620447	0.06%	$214	$3,112,659	$8,000	$1,558,412	$1,901,152
6	13620873	3.39%	$1,746	$19,750	$0	$8,762	$13,266
6	13621462	0.15%	$720	$75,150	$8,000	$19,155	$24,419
6	13622091	6.94%	$1,746	$29,625	$0	$147	$1,374
6	13623436	0.37%	$2,233	$81,000	$0	$22,770	$30,012
6	13623547	0.34%	$2,233	$81,000	$0	$23,529	$30,782
6	13625997	19.01%	$1,746	$19,750	$0	$5,509	$13,566
6	13629439	0.30%	$1,746	$54,313	$0	$35,804	$44,768
6	13630105	3.70%	$1,746	$54,313	$0	$13,086	$23,410
6	13631101	1.66%	$720	$22,500	$8,000	$2,280	$3,817
6	13631111	1.17%	$720	$112,500	$8,000	$4,746	$9,080
6	13632271	1.83%	$214	$3,112,659	$8,000	$348,618	$552,117
6	13632514	0.64%	$720	$75,150	$8,000	$9,739	$14,011
6	13633039	0.74%	$720	$45,000	$8,000	$7,224	$10,393
6	13633360	0.32%	$1,746	$54,313	$0	$35,228	$44,201
6	13634590	3.69%	$1,746	$29,625	$0	$4,130	$7,214
6	13637222	1.18%	$720	$75,150	$8,000	$3,910	$6,688
6	13638506	0.33%	$1,746	$54,313	$0	$35,118	$44,093
6	13638767	0.02%	$383	$32,813	$8,000	$16,593	$19,964
6	13640410	0.02%	$383	$309,375	$8,000	$122,495	$147,383

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES ON ISSUE 2.2

Job #	Asset Identifier	Failure Probability	Direct Cost ($)	Indirect Cost ($)		PV (2015 Cost of Deviation from Optimal) ($)	2012 Cost of Deviation from Optimal ($)
				Customer Interruption Cost ($)	Other Indirect Cost ($)		
6	13640446	0.24%	$1,746	$34,563	$0	$26,000	$32,153
6	13641050	0.22%	$720	$75,150	$8,000	$17,317	$22,402
6	13642390	0.31%	$2,233	$81,000	$0	$24,414	$31,680
6	13643365	0.36%	$2,233	$81,000	$0	$23,124	$30,371
6	13643401	0.37%	$1,746	$54,313	$0	$34,188	$43,180
6	13644507	0.27%	$214	$3,112,659	$8,000	$1,384,536	$1,711,533
6	13644902	0.30%	$2,233	$81,000	$0	$24,622	$31,891
6	13647835	0.19%	$720	$75,150	$8,000	$17,931	$23,014
6	13648366	0.35%	$2,233	$81,000	$0	$23,351	$30,602
6	13648745	0.29%	$2,233	$81,000	$0	$24,962	$32,236
6	13648894	0.16%	$214	$3,112,659	$8,000	$1,473,183	$1,808,056
6	13650342	0.29%	$2,233	$81,000	$0	$25,013	$32,287
6	13650493	0.30%	$1,746	$34,563	$0	$25,121	$31,338
6	13650949	0.32%	$1,746	$54,313	$0	$35,258	$44,231
6	13651033	0.38%	$720	$75,150	$8,000	$14,061	$18,661
6	13651181	0.37%	$1,746	$54,313	$0	$34,123	$43,117
6	13651336	0.44%	$1,746	$54,313	$0	$32,797	$41,817
6	13651514	0.01%	$383	$309,375	$8,000	$123,798	$148,694
6	13652897	0.29%	$1,746	$54,313	$0	$36,047	$45,007
6	14118112	9.00%	$540	$0	$4,000	$241	$91
6	14118187	7.57%	$540	$0	$4,000	$3,171	$0
6	14118189	7.57%	$540	$0	$4,000	$3,171	$0
6	14118190	7.57%	$540	$0	$4,000	$3,171	$0
6	14118191	7.57%	$540	$0	$4,000	$3,171	$0
6	14118192	7.57%	$540	$0	$4,000	$3,171	$0
6	14118193	7.57%	$540	$0	$4,000	$3,171	$0

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES ON ISSUE 2.2

Job #	Asset Identifier	Failure Probability	Direct Cost ($)	Indirect Cost ($)		PV (2015 Cost of Deviation from Optimal) ($)	2012 Cost of Deviation from Optimal ($)
				Customer Interruption Cost ($)	Other Indirect Cost ($)		
6	14118194	7.57%	$540	$0	$4,000	$3,171	$0
6	14118222	0.23%	$540	$0	$4,000	$3,818	$5,451
6	14118223	7.82%	$540	$0	$4,000	$2,025	$0
6	14118224	7.82%	$540	$0	$4,000	$2,025	$0
6	14118225	5.37%	$540	$0	$4,000	$0	$240
6	14118243	6.39%	$540	$0	$4,000	$10	$169
6	14118244	7.82%	$540	$0	$4,000	$2,025	$0
6	14118245	7.82%	$540	$0	$4,000	$2,025	$0
6	14118255	3.91%	$540	$0	$4,000	$16,932	$26,992
6	14118264	7.82%	$540	$0	$4,000	$2,025	$0
6	14118783	6.03%	$540	$0	$4,000	$5,662	$11,962
6	14118784	6.03%	$540	$0	$4,000	$5,662	$11,962
6	14118838	7.82%	$540	$0	$4,000	$1,681	$4,755
6	14118839	5.37%	$540	$0	$4,000	$8,478	$15,933
6	14118861	7.57%	$540	$0	$4,000	$3,171	$0
6	14118863	7.57%	$540	$0	$4,000	$3,171	$0
6	14118867	5.06%	$540	$0	$4,000	$10,027	$18,035
6	14119883	6.39%	$540	$0	$4,000	$8,105	$0
6	14119884	6.39%	$540	$0	$4,000	$8,105	$0
6	14119910	6.39%	$540	$0	$4,000	$8,105	$0
6	14119924	6.39%	$540	$0	$4,000	$8,105	$0
6	14119925	6.39%	$540	$0	$4,000	$8,105	$0
6	14119926	6.39%	$540	$0	$4,000	$8,105	$0
6	14119934	6.39%	$540	$0	$4,000	$8,105	$0
6	14119935	6.39%	$540	$0	$4,000	$8,105	$0
6	14119952	6.39%	$540	$0	$4,000	$8,105	$0

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES ON ISSUE 2.2

Job #	Asset Identifier	Failure Probability	Direct Cost ($)	Indirect Cost ($)		PV (2015 Cost of Deviation from Optimal) ($)	2012 Cost of Deviation from Optimal ($)
				Customer Interruption Cost ($)	Other Indirect Cost ($)		
6	14119959	5.37%	$8,016	$3,750	$1,600	$323	$1,072
6	14119982	6.39%	$540	$0	$4,000	$8,105	$0
6	28717142	7.74%	$1,746	$19,750	$0	$6,530	$12,024
6	28717173	8.22%	$1,746	$19,750	$0	$6,325	$11,929
6	28717178	7.36%	$1,746	$19,750	$0	$6,599	$12,008
6	28717188	5.19%	$1,746	$19,750	$0	$7,476	$12,391
6	28717225	21.06%	$1,746	$19,750	$0	$5,571	$14,095
6	28717365	4.91%	$1,746	$19,750	$0	$7,604	$12,453
6	28725371	0.04%	$720	$75,150	$8,000	$23,613	$28,643
6	28737040	9.23%	$2,233	$81,000	$0	$276	$3,364
6	28737042	3.41%	$2,233	$81,000	$0	$3,168	$9,248
6	28737044	0.28%	$2,233	$81,000	$0	$25,102	$32,377
6	28737046	9.35%	$2,233	$81,000	$0	$310	$3,342
6	28737049	0.29%	$2,233	$81,000	$0	$24,899	$32,171
6	28737051	7.54%	$2,233	$81,000	$0	$0	$4,497
6	28737053	0.34%	$2,233	$81,000	$0	$23,518	$30,771
6	28737055	0.35%	$2,233	$81,000	$0	$23,276	$30,525
6	28737057	10.96%	$2,233	$81,000	$0	$761	$3,046
6	28737059	5.15%	$2,233	$81,000	$0	$820	$6,231
6	28737061	0.30%	$2,233	$81,000	$0	$24,548	$31,816
6	28737063	0.32%	$2,233	$81,000	$0	$24,029	$31,289
6	28737065	5.56%	$2,233	$81,000	$0	$712	$5,967
6	28737067	5.63%	$2,233	$81,000	$0	$693	$5,920
6	28737069	0.32%	$2,233	$81,000	$0	$24,029	$31,289
6	28737071	0.31%	$2,233	$81,000	$0	$24,475	$31,742
6	28737073	4.15%	$2,233	$81,000	$0	$1,788	$7,585

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES ON ISSUE 2.2

Job #	Asset Identifier	Failure Probability	Direct Cost ($)	Indirect Cost ($)		PV (2015 Cost of Deviation from Optimal) ($)	2012 Cost of Deviation from Optimal ($)
				Customer Interruption Cost ($)	Other Indirect Cost ($)		
6	28737075	3.35%	$2,233	$81,000	$0	$3,252	$9,355
6	28737084	8.47%	$2,233	$81,000	$0	$61	$3,506
6	28737086	1.90%	$2,233	$81,000	$0	$7,323	$13,979
6	28737093	0.31%	$2,233	$81,000	$0	$24,341	$31,605
6	28742296	0.44%	$1,746	$54,313	$0	$32,788	$41,809
6	28742299	0.58%	$1,746	$54,313	$0	$30,443	$39,518
6	28742307	3.92%	$1,746	$54,313	$0	$12,744	$23,156
6	28742312	0.34%	$1,746	$54,313	$0	$34,830	$43,811
6	28742321	3.33%	$1,746	$54,313	$0	$13,968	$24,144
6	28742327	0.31%	$1,746	$54,313	$0	$35,646	$44,612
6	28742331	5.00%	$1,746	$54,313	$0	$10,894	$21,737
6	28742335	6.14%	$1,746	$54,313	$0	$9,631	$20,931
6	28742338	0.36%	$1,746	$54,313	$0	$34,501	$43,488
6	28742341	0.38%	$1,746	$54,313	$0	$33,921	$42,919
6	28742352	6.00%	$1,746	$54,313	$0	$9,722	$20,966
6	28742355	5.96%	$1,746	$54,313	$0	$9,748	$20,976
6	28742376	0.30%	$1,746	$54,313	$0	$35,794	$44,758
6	28742379	1.99%	$1,746	$54,313	$0	$18,528	$28,168
6	28742383	0.41%	$1,746	$54,313	$0	$33,415	$42,422
6	28742386	4.30%	$1,746	$54,313	$0	$11,975	$22,536
6	28742409	5.23%	$1,746	$34,563	$0	$15,910	$26,898
6	28742418	0.33%	$1,746	$34,563	$0	$24,768	$31,013
6	28742424	0.25%	$1,746	$34,563	$0	$25,777	$31,946
6	28742430	0.31%	$1,746	$34,563	$0	$24,996	$31,223
6	28742460	0.40%	$1,746	$34,563	$0	$24,049	$30,357
6	28742462	0.40%	$1,746	$34,563	$0	$24,058	$30,365

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES ON ISSUE 2.2

Job #	Asset Identifier	Failure Probability	Direct Cost ($)	Indirect Cost ($)		PV (2015 Cost of Deviation from Optimal) ($)	2012 Cost of Deviation from Optimal ($)
				Customer Interruption Cost ($)	Other Indirect Cost ($)		
6	28742468	4.89%	$1,746	$34,563	$0	$15,826	$26,485
6	28742470	10.41%	$1,746	$34,563	$0	$17,684	$33,688
6	28742472	0.33%	$1,746	$34,563	$0	$24,768	$31,013
6	28742474	4.93%	$1,746	$34,563	$0	$15,836	$26,533
6	28742476	0.35%	$1,746	$34,563	$0	$24,549	$30,812
6	28742478	1.05%	$1,746	$34,563	$0	$19,760	$26,701
6	28744197	18.03%	$1,746	$29,625	$0	$6,034	$0
6	28744256	2.07%	$383	$28,125	$8,000	$1,051	$2,313
6	28744311	0.71%	$383	$28,125	$8,000	$7,253	$9,663
6	28744321	5.14%	$1,746	$29,625	$0	$1,526	$3,780
6	28744329	16.22%	$1,746	$29,625	$0	$4,905	$0
6	28755293	4.65%	$540	$0	$4,000	$6,761	$0
6	28755312	4.65%	$540	$0	$4,000	$6,761	$0
6	28755340	5.66%	$540	$0	$4,000	$8,789	$0
6	28755422	1.42%	$540	$0	$4,000	$0	$994
6	28755434	6.39%	$540	$0	$4,000	$10,245	$0
6	28755444	1.24%	$540	$0	$4,000	$184	$1,521
6	28755677	6.39%	$540	$0	$4,000	$5,280	$0
6	28755691	6.39%	$540	$0	$4,000	$5,988	$0
6	28755711	6.39%	$540	$0	$4,000	$5,988	$0
6	28755728	6.39%	$540	$0	$4,000	$5,988	$0
6	28755736	0.27%	$540	$0	$4,000	$5,305	$8,473
6	28755745	6.39%	$540	$0	$4,000	$10,245	$0
6	28755766	0.05%	$540	$0	$4,000	$7,068	$10,893
6	30468106	3.17%	$1,746	$34,563	$0	$16,186	$25,183
6	30581457	7.63%	$1,746	$19,750	$0	$6,550	$12,020

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES ON ISSUE 2.2

Job #	Asset Identifier	Failure Probability	Direct Cost ($)	Indirect Cost ($)		PV (2015 Cost of Deviation from Optimal) ($)	2012 Cost of Deviation from Optimal ($)
				Customer Interruption Cost ($)	Other Indirect Cost ($)		
7	1220988	12.15%	$491	$0	$5,000	$363,674	$0
7	1221002	12.15%	$491	$0	$5,000	$363,674	$0
7	1221003	12.15%	$491	$0	$5,000	$363,674	$0
7	1221012	12.15%	$491	$0	$5,000	$363,674	$0
7	1221072	12.15%	$491	$0	$5,000	$363,674	$0
7	1221075	12.15%	$491	$0	$5,000	$363,674	$0
7	1664570	14.06%	$745	$0	$4,500	$208	$0
7	1664571	2.68%	$408	$0	$4,500	$18,183	$0
7	1664572	14.06%	$745	$0	$4,500	$66,110	$0
7	1664575	2.68%	$408	$0	$4,500	$18,183	$0
7	1664576	2.68%	$408	$0	$4,500	$18,183	$0
7	1664577	2.68%	$408	$0	$4,500	$18,183	$0
7	1664578	4.95%	$408	$0	$4,500	$20,446	$0
7	1664579	4.95%	$408	$0	$4,500	$20,446	$0
7	1664580	4.95%	$408	$0	$4,500	$20,446	$0
7	1664581	4.95%	$408	$0	$4,500	$20,446	$0
7	1664582	4.95%	$408	$0	$4,500	$20,446	$0
7	1664583	4.95%	$408	$0	$4,500	$20,446	$0
7	1672891	0.00%	$720	$146,250	$8,000	$40,136	$48,140
7	1676591	0.00%	$720	$146,250	$8,000	$40,256	$48,244
7	1680082	54.69%	$1,746	$19,750	$0	$14,247	$0
7	1680153	0.00%	$383	$257,813	$8,000	$108,243	$129,841
7	1682999	66.50%	$1,746	$26,366	$0	$30,244	$0
7	1683105	120.73%	$2,233	$202,500	$0	$680,909	$0
7	1683792	0.49%	$383	$257,813	$8,000	$62,282	$80,063
7	1687532	0.18%	$1,746	$271,563	$0	$145,557	$187,765

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES ON ISSUE 2.2

Job #	Asset Identifier	Failure Probability	Direct Cost ($)	Indirect Cost ($)		PV (2015 Cost of Deviation from Optimal) ($)	2012 Cost of Deviation from Optimal ($)
				Customer Interruption Cost ($)	Other Indirect Cost ($)		
7	1688639	0.57%	$720	$168,750	$8,000	$16,866	$23,497
7	1691333	68.50%	$2,233	$202,500	$0	$378,842	$0
7	1691424	1.33%	$416	$1,102,963	$8,000	$73,891	$121,143
7	1691512	0.62%	$416	$1,102,963	$8,000	$202,595	$268,858
7	1696539	0.02%	$416	$1,102,963	$8,000	$391,851	$478,515
7	1697728	1.48%	$1,746	$271,563	$0	$72,061	$123,365
7	1700479	3.15%	$1,746	$0	$0	$225,466	$271,705
7	1701019	5.03%	$416	$1,102,963	$8,000	$64,366	$0
7	1702609	0.00%	$383	$257,813	$8,000	$108,511	$130,082
7	1702718	0.03%	$720	$15,000	$8,000	$8,543	$10,517
7	1702991	0.03%	$383	$18,750	$8,000	$12,018	$14,704
7	1703176	0.49%	$416	$1,102,963	$8,000	$238,920	$308,654
7	1704357	3.67%	$1,746	$271,563	$0	$51,786	$118,104
7	1704846	0.41%	$720	$0	$8,000	$3,257	$4,080
7	1707163	0.01%	$720	$15,000	$8,000	$8,133	$9,869
7	1707395	184.58%	$2,233	$0	$0	$189,114	$235,710
7	1707466	182.81%	$1,746	$271,563	$0	$1,389,366	$0
7	1709561	6.34%	$416	$1,102,963	$8,000	$103,438	$0
7	1710013	4.64%	$1,746	$271,563	$0	$51,054	$124,022
7	1710958	1.02%	$1,746	$271,563	$0	$82,472	$130,613
7	1711372	0.02%	$416	$1,102,963	$8,000	$391,406	$478,140
7	1712657	0.04%	$383	$257,813	$8,000	$96,441	$119,287
7	2286042	4.18%	$416	$1,102,963	$8,000	$38,778	$0
7	2286060	1.05%	$720	$168,750	$8,000	$5,545	$10,072
7	2286162	1.11%	$720	$0	$8,000	$2,457	$3,297
7	2286405	0.11%	$416	$1,102,963	$8,000	$336,053	$434,607

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES ON ISSUE 2.2

Job #	Asset Identifier	Failure Probability	Direct Cost ($)	Indirect Cost ($)		PV (2015 Cost of Deviation from Optimal) ($)	2012 Cost of Deviation from Optimal ($)
				Customer Interruption Cost ($)	Other Indirect Cost ($)		
7	2286585	0.84%	$416	$1,102,963	$8,000	$152,879	$213,361
7	2286617	6.89%	$416	$1,102,963	$8,000	$120,143	$0
7	2286634	0.14%	$416	$1,102,963	$8,000	$324,281	$426,892
7	2286670	1.08%	$383	$257,813	$8,000	$29,509	$43,417
7	2286712	1.42%	$416	$1,102,963	$8,000	$63,795	$108,633
7	2286882	5.74%	$416	$1,102,963	$8,000	$85,429	$0
7	28783865	1.41%	$383	$154,688	$8,000	$11,518	$18,881
7	28783866	1.43%	$383	$154,688	$8,000	$11,338	$18,656
7	28783869	2.21%	$383	$154,688	$8,000	$2,220	$6,401
7	28784122	0.01%	$383	$154,688	$8,000	$63,852	$76,985
7	28784276	0.53%	$383	$154,688	$8,000	$36,638	$47,459
7	28784282	0.05%	$383	$154,688	$8,000	$57,534	$70,219
7	28784324	0.08%	$383	$154,688	$8,000	$56,068	$68,622
7	28784390	0.24%	$383	$154,688	$8,000	$49,363	$61,319
7	28784479	0.70%	$383	$154,688	$8,000	$30,080	$40,252
7	28784567	2.12%	$383	$154,688	$8,000	$2,873	$7,403
7	28784618	0.05%	$383	$154,688	$8,000	$57,307	$69,972
7	28784625	0.44%	$383	$154,688	$8,000	$40,784	$51,974
7	28784668	1.03%	$383	$154,688	$8,000	$20,002	$28,900
7	28784896	0.78%	$383	$154,688	$8,000	$27,449	$37,327
7	28784905	0.06%	$383	$154,688	$8,000	$57,109	$69,757
7	28785023	0.06%	$383	$154,688	$8,000	$56,830	$69,453
7	28785030	0.34%	$383	$154,688	$8,000	$44,813	$56,363
7	28785045	0.90%	$383	$154,688	$8,000	$23,578	$32,973
8	1673746	0.02%	$214	$1,714,978	$8,000	$948,414	$1,140,832
8	1675352	0.03%	$214	$1,714,978	$8,000	$936,322	$1,128,848

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES ON ISSUE 2.2

Job #	Asset Identifier	Failure Probability	Direct Cost ($)	Indirect Cost ($)		PV (2015 Cost of Deviation from Optimal) ($)	2012 Cost of Deviation from Optimal ($)
				Customer Interruption Cost ($)	Other Indirect Cost ($)		
8	1684818	0.07%	$214	$1,714,978	$8,000	$879,776	$1,072,799
8	1698575	5.20%	$1,746	$64,188	$0	$20,769	$39,137
8	1700459	5.14%	$1,746	$29,625	$0	$36,074	$54,359
8	1705302	19.73%	$1,746	$128,276	$0	$34,291	$0
8	1711212	7.98%	$1,746	$103,688	$0	$8,239	$27,663
8	1743022	0.93%	$540	$0	$4,000	$73	$817
8	1743028	1.24%	$540	$0	$4,000	$0	$1,048
8	1743040	2.00%	$540	$0	$4,000	$268	$1,371
8	1743064	2.00%	$540	$0	$4,000	$268	$1,371
8	2407853	0.01%	$383	$60,938	$8,000	$27,679	$33,279
8	28161733	0.01%	$383	$28,125	$8,000	$15,046	$18,089
8	28161739	0.01%	$383	$98,438	$8,000	$42,125	$50,648
8	28751016	0.00%	$383	$28,125	$8,000	$15,201	$18,217
8	28751017	0.00%	$383	$28,125	$8,000	$15,199	$18,215
8	28751018	0.00%	$383	$28,125	$8,000	$15,199	$18,215
8	28751020	0.00%	$383	$28,125	$8,000	$15,200	$18,216
8	28840586	0.00%	$383	$98,438	$8,000	$42,798	$51,292
8	30487139	2.00%	$540	$0	$4,000	$29	$364
8	30487162	1.50%	$1,746	$29,625	$0	$23,537	$32,556
8	30487177	0.00%	$383	$28,125	$8,000	$15,548	$18,567
8	30487180	2.00%	$540	$0	$4,000	$29	$364
8	30487194	0.00%	$383	$28,125	$8,000	$15,551	$18,571
8	30487195	0.00%	$383	$28,125	$8,000	$15,554	$18,575
8	30487232	0.00%	$1,746	$29,625	$0	$56,251	$69,020
8	30487246	0.00%	$1,746	$29,625	$0	$41,580	$50,741
8	30487510	3.94%	$1,746	$64,188	$0	$21,250	$37,657

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES ON ISSUE 2.2

Job #	Asset Identifier	Failure Probability	Direct Cost ($)	Indirect Cost ($)		PV (2015 Cost of Deviation from Optimal) ($)	2012 Cost of Deviation from Optimal ($)
				Customer Interruption Cost ($)	Other Indirect Cost ($)		
8	30487513	1.78%	$1,746	$64,188	$0	$25,509	$38,575
8	30487581	0.00%	$383	$60,938	$8,000	$28,734	$34,314
8	30487587	1.24%	$540	$0	$4,000	$0	$1,048
8	30487817	0.00%	$1,746	$64,188	$0	$53,639	$64,441
8	30487821	0.00%	$383	$60,938	$8,000	$28,736	$34,318
8	30487848	1.24%	$540	$0	$4,000	$235	$220
8	30487893	2.20%	$1,746	$64,188	$0	$24,075	$37,797
8	30487910	2.03%	$1,746	$64,188	$0	$24,661	$38,106
8	30487982	0.00%	$383	$60,938	$8,000	$28,732	$34,312
8	30487999	1.24%	$540	$0	$4,000	$235	$220
8	30488062	0.00%	$383	$60,938	$8,000	$28,742	$34,327
8	30488082	1.24%	$540	$0	$4,000	$235	$220
8	30488136	4.74%	$1,746	$64,188	$0	$21,108	$38,756
8	30488164	0.00%	$383	$60,938	$8,000	$28,741	$34,325
8	30488177	1.24%	$540	$0	$4,000	$0	$1,048
8	30488190	2.52%	$1,746	$64,188	$0	$23,289	$37,508
8	30488192	6.68%	$1,746	$64,188	$0	$20,636	$41,293
8	30488193	0.00%	$383	$60,938	$8,000	$28,738	$34,320
8	30488201	1.24%	$540	$0	$4,000	$235	$220
8	30488259	1.54%	$1,746	$103,688	$0	$31,189	$47,970
8	30488266	0.00%	$383	$98,438	$8,000	$43,798	$52,305
8	30488274	0.93%	$540	$0	$4,000	$73	$817
8	30488325	1.87%	$1,746	$103,688	$0	$27,760	$44,675
8	30488335	0.00%	$383	$98,438	$8,000	$43,809	$52,323
8	30488339	0.93%	$540	$0	$4,000	$73	$817
8	30488385	0.93%	$540	$0	$4,000	$73	$817

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES ON ISSUE 2.2

Job #	Asset Identifier	Failure Probability	Direct Cost ($)	Indirect Cost ($)		PV (2015 Cost of Deviation from Optimal) ($)	2012 Cost of Deviation from Optimal ($)
				Customer Interruption Cost ($)	Other Indirect Cost ($)		
8	30488449	0.00%	$383	$98,438	$8,000	$43,801	$52,310
8	30488450	0.00%	$383	$98,438	$8,000	$43,799	$52,306
8	30488461	0.93%	$540	$0	$4,000	$522	$198
8	30488465	3.85%	$1,746	$103,688	$0	$16,719	$34,447
8	30488470	2.93%	$1,746	$103,688	$0	$20,262	$37,612
8	30488526	1.11%	$1,746	$103,688	$0	$37,332	$53,933
8	30488527	0.00%	$383	$98,438	$8,000	$43,801	$52,309
8	30488546	0.93%	$540	$0	$4,000	$73	$817
8	30488608	0.00%	$383	$98,438	$8,000	$43,799	$52,306
8	30488624	0.93%	$540	$0	$4,000	$73	$817
8	30488966	0.00%	$383	$98,438	$8,000	$43,803	$52,313
8	30488967	0.00%	$383	$98,438	$8,000	$43,801	$52,308
8	30488984	1.12%	$1,746	$103,688	$0	$37,076	$53,684
8	30488985	2.28%	$1,746	$103,688	$0	$24,303	$41,386
8	30489007	0.93%	$540	$0	$4,000	$73	$817
8	30489073	1.91%	$1,746	$103,688	$0	$27,437	$44,369
8	30489100	0.00%	$383	$98,438	$8,000	$43,801	$52,309
8	30489101	0.00%	$383	$98,438	$8,000	$43,799	$52,306
8	30489137	0.93%	$540	$0	$4,000	$73	$817
8	30489158	1.07%	$1,746	$103,688	$0	$37,889	$54,476
8	30489168	0.00%	$383	$98,438	$8,000	$43,797	$52,302
8	30489179	0.93%	$540	$0	$4,000	$73	$817
8	30489201	1.54%	$1,746	$103,688	$0	$31,224	$48,004
8	30489214	0.00%	$383	$98,438	$8,000	$43,798	$52,304
8	30489239	0.93%	$540	$0	$4,000	$73	$817
8	30489279	0.00%	$1,746	$103,688	$0	$159,674	$202,414

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES ON ISSUE 2.2

Job #	Asset Identifier	Failure Probability	Direct Cost ($)	Indirect Cost ($)		PV (2015 Cost of Deviation from Optimal) ($)	2012 Cost of Deviation from Optimal ($)
				Customer Interruption Cost ($)	Other Indirect Cost ($)		
8	30489345	2.70%	$1,746	$64,188	$0	$23,021	$37,520
8	30489357	0.00%	$383	$60,938	$8,000	$28,742	$34,326
8	30489376	1.24%	$540	$0	$4,000	$235	$220
8	30489399	1.24%	$540	$0	$4,000	$0	$1,048
8	30490042	0.00%	$383	$98,438	$8,000	$43,797	$52,302
8	30490185	0.00%	$383	$98,438	$8,000	$43,816	$52,335
8	30490316	0.00%	$383	$60,938	$8,000	$28,736	$34,317
8	30490320	0.00%	$383	$60,938	$8,000	$28,736	$34,318
8	30491002	0.00%	$383	$98,438	$8,000	$43,801	$52,309
8	30491042	0.00%	$383	$98,438	$8,000	$43,799	$52,305
8	30491046	0.00%	$383	$98,438	$8,000	$43,799	$52,306
8	30491387	0.00%	$383	$60,938	$8,000	$28,743	$34,328
8	30491391	0.00%	$383	$60,938	$8,000	$28,732	$34,312
8	30492358	0.07%	$383	$28,125	$8,000	$14,094	$17,305
8	30492360	3.70%	$1,746	$64,188	$0	$21,686	$37,732
9	1170207	1.71%	$208	$149,422	$385	$4,091	$0
9	1170209	1.71%	$212	$143,677	$385	$3,832	$0
9	1171055	3.25%	$199	$146,180	$385	$10,716	$0
9	1171062	27.32%	$216	$139,842	$385	$107,590	$0
9	1171741	4.48%	$197	$142,134	$385	$15,456	$0
9	1171742	1.71%	$197	$148,877	$385	$4,332	$0
9	1171744	1.71%	$191	$138,089	$385	$3,999	$0
9	1171747	1.71%	$192	$138,089	$385	$3,964	$0
9	1171750	4.48%	$199	$142,134	$385	$15,421	$0
9	1171761	0.60%	$195	$138,693	$385	$96	$754
9	1171767	1.34%	$197	$139,302	$385	$2,721	$0

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES ON ISSUE 2.2

Job #	Asset Identifier	Failure Probability	Direct Cost ($)	Indirect Cost ($)		PV (2015 Cost of Deviation from Optimal) ($)	2012 Cost of Deviation from Optimal ($)
				Customer Interruption Cost ($)	Other Indirect Cost ($)		
9	1171768	0.60%	$199	$139,302	$385	$93	$743
9	1171892	4.48%	$261	$139,707	$385	$16,145	$0
9	1172066	16.06%	$195	$2,562	$385	$269	$893
9	1173274	4.48%	$197	$138,089	$385	$18,619	$0
9	1173282	0.60%	$202	$139,707	$385	$81	$690
9	1669377	0.09%	$270	$3,320,250	$8,000	$1,466,457	$1,783,987
9	1670026	0.03%	$270	$3,320,250	$8,000	$1,561,316	$1,886,614
9	1670549	0.11%	$270	$3,320,250	$8,000	$1,453,003	$1,769,708
9	1670591	0.03%	$270	$3,320,250	$8,000	$1,566,696	$1,891,952
9	1671382	0.02%	$720	$71,250	$8,000	$23,563	$28,439
9	1671574	0.10%	$270	$3,320,250	$8,000	$1,460,571	$1,777,740
9	1672263	0.01%	$270	$3,320,250	$8,000	$1,611,680	$1,936,580
9	1672874	0.01%	$720	$272,550	$8,000	$70,034	$84,144
9	1674082	0.07%	$270	$3,320,250	$8,000	$1,495,383	$1,814,686
9	1674673	0.13%	$270	$3,320,250	$8,000	$1,428,955	$1,744,185
9	1676016	0.13%	$270	$3,320,250	$8,000	$1,418,528	$1,733,120
9	1676122	0.02%	$270	$3,320,250	$8,000	$1,600,337	$1,925,326
9	1676636	0.01%	$270	$3,320,250	$8,000	$1,616,671	$1,941,531
9	1678530	0.70%	$720	$300,150	$8,000	$21,295	$32,511
9	1680408	73.95%	$1,663	$3,762,950	$0	$7,785,639	$0
9	1685381	0.08%	$720	$33,750	$8,000	$13,534	$16,770
9	1688215	0.24%	$720	$16,800	$8,000	$10,113	$12,928
9	1689873	0.13%	$720	$45,000	$8,000	$14,802	$18,695
9	1690003	0.00%	$720	$22,500	$8,000	$12,640	$15,132
9	1690321	50.29%	$2,233	$270,000	$0	$380,298	$0
9	1692942	0.12%	$720	$33,750	$8,000	$13,070	$16,396

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES ON ISSUE 2.2

Job #	Asset Identifier	Failure Probability	Direct Cost ($)	Indirect Cost ($)		PV (2015 Cost of Deviation from Optimal) ($)	2012 Cost of Deviation from Optimal ($)
				Customer Interruption Cost ($)	Other Indirect Cost ($)		
9	1693655	33.14%	$2,233	$40,500	$0	$30,196	$0
9	1694429	4.45%	$2,233	$57,060	$0	$14,151	$27,339
9	1696762	1.10%	$2,233	$27,000	$0	$9,075	$13,289
9	1699336	0.70%	$2,233	$54,000	$0	$12,609	$18,224
9	1704932	14.17%	$2,233	$135,000	$0	$43,225	$0
9	1705393	1.89%	$720	$149,850	$8,000	$258	$2,361
9	1708641	1.90%	$2,233	$36,000	$0	$16,126	$24,321
9	1709618	117.14%	$2,233	$360,000	$0	$1,230,628	$0
9	1710076	2.92%	$2,233	$36,000	$0	$18,628	$29,212
9	1711998	22.32%	$2,233	$135,000	$0	$75,184	$0
9	1742217	4.47%	$540	$0	$4,000	$432	$3,957
9	1742224	0.38%	$540	$0	$4,000	$36,121	$55,275
9	1742641	11.16%	$540	$0	$4,000	$38,622	$0
9	1742642	11.16%	$540	$0	$2,000	$3,023	$0
9	1742940	11.16%	$540	$0	$4,000	$12,110	$0
9	1742943	11.16%	$540	$0	$4,000	$12,110	$0
9	1742951	3.91%	$540	$0	$4,000	$8,962	$14,094
9	1742976	3.91%	$540	$0	$4,000	$8,962	$14,094
9	28134934	0.15%	$720	$47,550	$8,000	$12,384	$15,899
9	28158902	0.15%	$720	$30,000	$8,000	$9,648	$12,315
9	30495668	0.25%	$2,233	$36,000	$0	$15,447	$19,765
9	30495670	0.25%	$2,233	$36,000	$0	$15,432	$19,756
9	30517976	0.11%	$2,233	$27,000	$0	$18,733	$24,172
9	30518598	0.01%	$720	$45,000	$8,000	$17,641	$21,219
9	30518600	0.01%	$720	$45,000	$8,000	$17,551	$21,137
9	30545598	0.13%	$720	$33,750	$8,000	$12,822	$15,750

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES ON ISSUE 2.2

Job #	Asset Identifier	Failure Probability	Direct Cost ($)	Indirect Cost ($)		PV (2015 Cost of Deviation from Optimal) ($)	2012 Cost of Deviation from Optimal ($)
				Customer Interruption Cost ($)	Other Indirect Cost ($)		
9	30545619	0.08%	$720	$33,750	$8,000	$13,483	$16,436
10	1669024	0.00%	$214	$1,200,084	$8,000	$684,233	$818,905
10	1671784	0.00%	$214	$1,200,084	$8,000	$684,256	$818,926
10	1672302	0.00%	$383	$25,031	$8,000	$14,163	$16,943
10	1674071	0.01%	$214	$1,200,084	$8,000	$674,390	$809,780
10	1674761	0.00%	$214	$1,200,084	$8,000	$684,602	$819,987
10	1675710	0.01%	$214	$1,200,084	$8,000	$675,616	$810,916
10	1678532	0.00%	$383	$25,031	$8,000	$14,162	$16,947
10	1680959	0.00%	$383	$56,250	$8,000	$29,211	$35,003
10	1681587	0.00%	$214	$1,200,084	$8,000	$686,077	$820,614
10	1682076	0.01%	$383	$56,250	$8,000	$29,076	$34,912
10	1682810	0.03%	$1,746	$59,250	$0	$64,459	$83,752
10	1682910	0.00%	$383	$56,250	$8,000	$29,210	$35,002
10	1683842	0.00%	$383	$16,406	$8,000	$10,741	$12,852
10	1684300	0.00%	$383	$25,031	$8,000	$14,163	$16,940
10	1684748	12.46%	$1,746	$17,281	$0	$71	$517
10	1684992	1.60%	$1,746	$17,281	$0	$87,830	$113,534
10	1685806	1.37%	$1,746	$26,366	$0	$46,021	$62,823
10	1687207	0.05%	$383	$16,406	$8,000	$9,366	$11,436
10	1687530	0.00%	$383	$16,406	$8,000	$10,733	$12,838
10	1687690	15.43%	$1,746	$17,281	$0	$572	$0
10	1688143	0.00%	$383	$25,031	$8,000	$14,163	$16,941
10	1688202	0.00%	$383	$25,031	$8,000	$14,162	$16,947
10	1688855	0.07%	$383	$56,250	$8,000	$27,202	$34,096
10	1689923	0.00%	$214	$1,200,084	$8,000	$685,999	$820,541
10	1690659	0.05%	$383	$56,250	$8,000	$27,493	$34,040

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES ON ISSUE 2.2

Job #	Asset Identifier	Failure Probability	Direct Cost ($)	Indirect Cost ($)		PV (2015 Cost of Deviation from Optimal) ($)	2012 Cost of Deviation from Optimal ($)
				Customer Interruption Cost ($)	Other Indirect Cost ($)		
10	1692108	1.26%	$1,746	$14,813	$0	$47,139	$61,739
10	1693031	0.00%	$214	$1,200,084	$8,000	$686,018	$820,560
10	1693102	103.53%	$1,746	$16,491	$0	$20,749	$0
10	1693919	0.00%	$383	$56,250	$8,000	$29,214	$35,005
10	1696103	0.08%	$383	$56,250	$8,000	$27,149	$34,139
10	1696599	0.00%	$383	$56,250	$8,000	$29,206	$35,000
10	1698630	0.00%	$383	$56,250	$8,000	$29,207	$35,000
10	1698682	0.00%	$383	$25,031	$8,000	$14,162	$16,947
10	1699068	0.00%	$383	$16,406	$8,000	$10,741	$12,852
10	1699491	0.07%	$383	$15,656	$8,000	$9,029	$11,037
10	1699536	0.83%	$1,746	$14,813	$0	$35,246	$45,833
10	1700343	0.07%	$383	$16,406	$8,000	$9,282	$11,346
10	1701172	0.05%	$383	$15,656	$8,000	$9,141	$11,156
10	1702791	0.00%	$383	$56,250	$8,000	$29,218	$35,008
10	1704273	0.07%	$383	$16,406	$8,000	$9,286	$11,351
10	1705590	0.46%	$1,746	$26,366	$0	$28,099	$36,872
10	1706607	0.00%	$383	$56,250	$8,000	$29,213	$35,004
10	1709009	0.07%	$383	$15,656	$8,000	$9,024	$11,031
10	1710752	0.00%	$383	$56,250	$8,000	$29,218	$35,008
10	1710831	0.50%	$1,746	$14,813	$0	$26,464	$34,033
10	1711427	1.99%	$1,746	$59,250	$0	$30,413	$49,344
10	1712334	0.00%	$383	$56,250	$8,000	$29,220	$35,010
11	13620085	0.02%	$383	$229,688	$8,000	$89,107	$110,608
11	13620787	0.41%	$1,746	$241,938	$0	$88,869	$130,858
11	13622148	0.46%	$1,746	$241,938	$0	$85,482	$128,083
11	13622858	0.01%	$383	$492,188	$8,000	$194,972	$236,028

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES ON ISSUE 2.2

Job #	Asset Identifier	Failure Probability	Direct Cost ($)	Indirect Cost ($)		PV (2015 Cost of Deviation from Optimal) ($)	2012 Cost of Deviation from Optimal ($)
				Customer Interruption Cost ($)	Other Indirect Cost ($)		
11	13623007	0.03%	$1,746	$241,938	$0	$158,248	$195,794
11	13625107	1.33%	$1,746	$266,625	$0	$79,199	$142,565
11	13626164	0.36%	$1,746	$518,438	$0	$170,124	$250,307
11	13626562	0.01%	$383	$229,688	$8,000	$90,663	$110,230
11	13627319	0.12%	$1,746	$518,438	$0	$252,248	$330,998
11	13627500	0.08%	$1,592	$2,599,740	$0	$2,233,239	$2,803,896
11	13627909	0.07%	$1,746	$39,500	$0	$37,749	$47,137
11	13629553	0.02%	$383	$492,188	$8,000	$179,759	$223,325
11	13629856	0.02%	$383	$492,188	$8,000	$183,877	$226,726
11	13631744	0.41%	$1,746	$518,438	$0	$160,627	$241,076
11	13632755	0.18%	$1,746	$241,938	$0	$112,993	$152,277
11	13633278	0.00%	$383	$322,688	$8,000	$133,445	$159,600
11	13633985	0.11%	$214	$2,333,100	$8,000	$1,171,465	$1,428,933
11	13635832	0.02%	$383	$492,188	$8,000	$183,920	$226,761
11	13637271	0.44%	$1,746	$241,938	$0	$86,323	$128,726
11	13637383	0.53%	$1,746	$339,898	$0	$112,089	$171,952
11	13638077	0.01%	$1,746	$39,500	$0	$34,086	$41,187
11	13639784	1.47%	$1,746	$266,625	$0	$79,085	$144,746
11	13639940	1.39%	$1,746	$266,625	$0	$79,152	$143,494
11	13640338	0.87%	$2,233	$0	$0	$104,088	$125,555
11	13640846	1.72%	$1,746	$266,625	$0	$77,128	$146,911
11	13641161	0.09%	$214	$2,333,100	$8,000	$1,196,707	$1,454,820
11	13641417	0.84%	$1,746	$339,898	$0	$96,020	$160,573
11	13642631	0.00%	$214	$2,333,100	$8,000	$1,335,509	$1,596,305
11	13644148	0.55%	$1,746	$518,438	$0	$138,704	$219,888
11	13644452	0.19%	$1,746	$518,438	$0	$218,207	$297,390

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES ON ISSUE 2.2

Job #	Asset Identifier	Failure Probability	Direct Cost ($)	Indirect Cost ($)		PV (2015 Cost of Deviation from Optimal) ($)	2012 Cost of Deviation from Optimal ($)
				Customer Interruption Cost ($)	Other Indirect Cost ($)		
11	13645678	0.35%	$1,746	$518,438	$0	$172,966	$253,064
11	13647507	0.00%	$383	$18,750	$8,000	$11,686	$13,976
11	13647588	0.02%	$383	$492,188	$8,000	$178,612	$222,387
11	13647965	0.46%	$1,746	$518,438	$0	$152,662	$233,348
11	13647997	0.06%	$214	$2,333,100	$8,000	$1,231,217	$1,490,212
11	13648240	0.01%	$383	$492,188	$8,000	$192,859	$234,242
11	13649331	0.55%	$1,746	$518,438	$0	$138,842	$220,021
11	13649660	1.18%	$1,746	$339,898	$0	$85,753	$155,370
11	13650492	0.00%	$214	$2,333,100	$8,000	$1,335,164	$1,596,003
11	13650842	0.00%	$383	$322,688	$8,000	$133,443	$159,590
11	13651165	0.01%	$383	$229,688	$8,000	$90,658	$110,226
11	13651415	1.71%	$1,746	$339,898	$0	$78,435	$155,885
11	13652027	0.34%	$1,746	$518,438	$0	$175,906	$255,948
11	13652560	2.77%	$1,746	$339,898	$0	$70,653	$163,352
11	13653743	0.01%	$383	$23,438	$8,000	$13,471	$16,419
11	13653873	1.97%	$1,746	$518,438	$0	$55,349	$142,095
11	14077878	0.43%	$580	$6,240	$2,800	$73	$206
11	14077879	0.43%	$580	$6,240	$2,800	$73	$206
11	14123147	2.92%	$540	$0	$4,000	$1,122	$0
11	14123160	1.08%	$540	$0	$4,000	$1,164	$3,138
11	14123161	1.79%	$540	$0	$4,000	$0	$921
11	14123169	6.77%	$540	$0	$4,000	$3,178	$0
11	14123186	6.02%	$540	$0	$4,000	$5,769	$0
11	14123187	8.41%	$540	$0	$4,000	$9,302	$0
11	14123235	0.67%	$540	$0	$4,000	$2,630	$5,230
11	14123238	0.67%	$540	$0	$4,000	$2,630	$5,230

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES ON ISSUE 2.2

Job #	Asset Identifier	Failure Probability	Direct Cost ($)	Indirect Cost ($)		PV (2015 Cost of Deviation from Optimal) ($)	2012 Cost of Deviation from Optimal ($)
				Customer Interruption Cost ($)	Other Indirect Cost ($)		
11	14124271	0.27%	$540	$0	$4,000	$4,513	$7,810
11	14124290	6.02%	$540	$0	$4,000	$8,497	$0
11	14124291	6.02%	$540	$0	$4,000	$5,501	$0
11	14124292	6.02%	$540	$0	$4,000	$8,497	$0
11	14124304	6.02%	$540	$0	$4,000	$5,501	$0
11	14124305	6.02%	$540	$0	$4,000	$5,501	$0
11	14124306	6.02%	$540	$0	$4,000	$8,497	$0
11	14124307	7.16%	$540	$0	$4,000	$6,296	$0
11	14124308	4.65%	$540	$0	$4,000	$5,230	$0
11	14124309	6.02%	$540	$0	$4,000	$8,497	$0
11	14124388	0.35%	$540	$0	$4,000	$4,710	$7,761
11	14131705	2.92%	$540	$0	$4,000	$1,122	$0
11	28811096	0.01%	$383	$18,750	$8,000	$11,683	$14,123
11	28824959	12.96%	$1,746	$34,563	$0	$4,737	$13,568
11	28824967	9.56%	$1,746	$34,563	$0	$5,633	$13,702
11	28824971	8.77%	$1,746	$34,563	$0	$5,815	$13,706
11	28824975	9.79%	$1,746	$34,563	$0	$5,582	$13,701
11	28824980	7.38%	$1,746	$34,563	$0	$6,550	$14,130
11	28824985	0.22%	$1,746	$49,375	$0	$56,863	$73,741
11	28824987	19.85%	$1,746	$49,375	$0	$383	$3,664
11	28824994	11.98%	$1,746	$49,375	$0	$735	$6,451
11	28824996	0.45%	$1,746	$49,375	$0	$30,663	$38,687
11	28824998	5.54%	$1,746	$49,375	$0	$5,159	$12,165
11	28825017	11.19%	$1,746	$49,375	$0	$845	$6,719
11	30326489	0.27%	$1,746	$39,500	$0	$59,279	$76,667
11	30326549	0.01%	$1,746	$39,500	$0	$34,097	$41,259

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES ON ISSUE 2.2

Job #	Asset Identifier	Failure Probability	Direct Cost ($)	Indirect Cost ($)		PV (2015 Cost of Deviation from Optimal) ($)	2012 Cost of Deviation from Optimal ($)
				Customer Interruption Cost ($)	Other Indirect Cost ($)		
11	30326563	0.25%	$1,746	$39,500	$0	$57,138	$73,760
11	30326720	0.31%	$1,746	$39,500	$0	$63,697	$82,613
11	30326740	0.20%	$1,746	$39,500	$0	$51,261	$65,804
11	30326841	0.33%	$1,746	$39,500	$0	$66,031	$85,778
11	30326843	0.01%	$1,746	$39,500	$0	$34,104	$41,290
11	30326900	0.16%	$1,746	$39,500	$0	$47,385	$60,531
11	30327123	0.04%	$1,746	$39,500	$0	$35,729	$44,159
11	30329383	0.37%	$1,746	$49,375	$0	$32,082	$40,122
11	30329406	0.37%	$1,746	$34,563	$0	$24,271	$30,278
11	30329440	0.38%	$1,746	$34,563	$0	$24,186	$30,195
11	30329881	0.38%	$1,746	$49,375	$0	$31,983	$40,022
11	30403123	0.96%	$1,746	$49,375	$0	$30,391	$41,898
11	30443625	14.66%	$1,746	$49,375	$0	$0	$5,179
11	30443813	0.32%	$1,746	$39,500	$0	$64,709	$83,975
11	30444116	0.00%	$383	$32,813	$8,000	$17,327	$20,711
11	30491723	0.00%	$383	$229,688	$8,000	$100,339	$121,666
11	30491725	0.00%	$383	$229,688	$8,000	$100,209	$121,388
11	30563604	0.00%	$383	$46,875	$8,000	$23,630	$28,338
12	13618252	0.00%	$416	$5,553,373	$8,000	$2,094,547	$2,504,276
12	13618263	0.09%	$720	$142,500	$8,000	$32,733	$40,179
12	13618327	0.00%	$416	$5,553,373	$8,000	$2,095,280	$2,504,921
12	13618364	0.00%	$720	$105,000	$8,000	$30,374	$36,327
12	13619612	0.00%	$383	$0	$8,000	$4,289	$5,130
12	13622869	14.74%	$2,233	$90,000	$0	$26,521	$0
12	13627338	0.05%	$720	$75,000	$8,000	$19,949	$24,322
12	13628047	0.03%	$720	$75,000	$8,000	$20,484	$24,894

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES ON ISSUE 2.2

Job #	Asset Identifier	Failure Probability	Direct Cost ($)	Indirect Cost ($)		PV (2015 Cost of Deviation from Optimal) ($)	2012 Cost of Deviation from Optimal ($)
				Customer Interruption Cost ($)	Other Indirect Cost ($)		
12	13629489	7.83%	$1,746	$19,750	$0	$1,262	$3,528
12	13630588	0.04%	$720	$172,500	$8,000	$41,586	$50,626
12	13630870	9.57%	$1,746	$29,625	$0	$119	$675
12	13631323	0.78%	$383	$28,125	$8,000	$6,734	$9,185
12	13631339	7.69%	$2,233	$90,000	$0	$9,954	$0
12	13631407	0.20%	$2,233	$108,900	$0	$47,752	$65,243
12	13632658	6.12%	$2,233	$90,000	$0	$6,257	$0
12	13638819	0.00%	$720	$75,150	$8,000	$25,636	$30,713
12	13640935	0.06%	$416	$5,553,373	$8,000	$1,841,000	$2,241,569
12	13641107	0.01%	$383	$18,750	$8,000	$11,281	$13,560
12	13642661	32.11%	$1,746	$19,750	$0	$3,518	$0
12	13643897	22.81%	$1,746	$19,750	$0	$1,417	$0
12	13644201	0.00%	$416	$5,553,373	$8,000	$2,084,342	$2,496,168
12	13645463	0.00%	$416	$5,553,373	$8,000	$2,094,331	$2,504,086
12	13645668	0.00%	$383	$0	$8,000	$4,247	$5,078
12	13646308	0.00%	$720	$90,750	$8,000	$26,826	$32,084
12	13646966	0.02%	$383	$18,750	$8,000	$11,204	$13,488
12	13647637	0.06%	$416	$5,553,373	$8,000	$1,840,776	$2,241,329
12	13653808	48.80%	$2,233	$90,000	$0	$106,579	$0
12	14128684	0.35%	$540	$0	$4,000	$3,859	$6,995
12	14128685	0.35%	$540	$0	$4,000	$3,859	$6,995
12	14128686	0.35%	$540	$0	$4,000	$3,859	$6,995
12	14128687	16.12%	$540	$0	$4,000	$25,931	$0
12	14128688	0.35%	$540	$0	$4,000	$5,953	$8,838
12	14128689	0.35%	$540	$0	$4,000	$3,859	$6,995
12	14128690	0.35%	$540	$0	$4,000	$5,953	$8,838

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES ON ISSUE 2.2

Job #	Asset Identifier	Failure Probability	Direct Cost ($)	Indirect Cost ($)		PV (2015 Cost of Deviation from Optimal) ($)	2012 Cost of Deviation from Optimal ($)
				Customer Interruption Cost ($)	Other Indirect Cost ($)		
12	14128691	16.12%	$540	$0	$4,000	$15,251	$0
12	14128692	0.35%	$540	$0	$4,000	$5,105	$8,113
12	14129284	8.41%	$540	$0	$4,000	$14,881	$0
12	14129285	9.29%	$540	$0	$4,000	$16,777	$0
12	14129286	1.08%	$540	$0	$4,000	$359	$1,905
12	14129288	7.57%	$540	$0	$4,000	$13,986	$0
12	14129289	7.57%	$540	$0	$4,000	$13,202	$0
12	14129290	7.57%	$540	$0	$4,000	$13,202	$0
12	14129291	0.35%	$540	$0	$4,000	$7,140	$9,827
12	14129296	1.08%	$540	$0	$4,000	$137	$1,441
12	14129298	7.57%	$540	$0	$4,000	$13,202	$0
12	14129299	1.79%	$540	$0	$4,000	$428	$149
12	14129300	7.57%	$540	$0	$4,000	$13,075	$0
12	14129322	7.57%	$540	$0	$4,000	$13,075	$0
12	14129345	7.57%	$540	$0	$4,000	$13,202	$0
12	14129355	0.35%	$540	$0	$4,000	$7,140	$9,827
12	14129357	58.32%	$540	$0	$4,000	$0	$0
12	14129358	0.91%	$540	$0	$4,000	$46,217	$61,686
12	14129395	5.31%	$540	$0	$4,000	$1,354	$0
12	14129396	5.31%	$540	$0	$4,000	$1,354	$0
12	14129420	9.29%	$540	$0	$4,000	$4,552	$0
12	14131665	0.09%	$540	$0	$4,000	$5,942	$9,851
12	28159957	41.92%	$1,746	$29,625	$0	$16,702	$0
12	28159964	0.05%	$383	$18,750	$8,000	$10,519	$12,777
12	28159993	0.04%	$720	$75,000	$8,000	$20,191	$24,581
12	28159999	0.03%	$720	$75,000	$8,000	$20,467	$24,875

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES ON ISSUE 2.2

Job #	Asset Identifier	Failure Probability	Direct Cost ($)	Indirect Cost ($)		PV (2015 Cost of Deviation from Optimal) ($)	2012 Cost of Deviation from Optimal ($)
				Customer Interruption Cost ($)	Other Indirect Cost ($)		
12	28160001	0.05%	$720	$75,000	$8,000	$20,152	$24,538
12	28160005	0.05%	$720	$75,000	$8,000	$19,925	$24,296
12	28160194	0.52%	$383	$28,125	$8,000	$8,856	$11,493
12	28160234	0.03%	$383	$28,125	$8,000	$13,985	$16,969
12	28160236	0.04%	$383	$28,125	$8,000	$13,935	$16,917
12	28160240	0.03%	$383	$28,125	$8,000	$13,983	$16,968
12	28160268	0.06%	$383	$28,125	$8,000	$13,775	$16,748
12	28160272	0.04%	$383	$28,125	$8,000	$13,971	$16,955
12	28160276	0.04%	$383	$28,125	$8,000	$13,964	$16,948
12	28160278	0.05%	$383	$28,125	$8,000	$13,863	$16,841
12	28160378	0.51%	$383	$18,750	$8,000	$7,316	$9,424
12	28160910	0.03%	$383	$18,750	$8,000	$10,604	$12,867
12	28161181	25.36%	$1,746	$19,750	$0	$1,993	$0
12	28161182	0.04%	$383	$18,750	$8,000	$10,579	$12,840
12	28161185	0.04%	$383	$18,750	$8,000	$10,565	$12,825
12	28161187	0.04%	$383	$18,750	$8,000	$10,529	$12,788
12	28161194	0.05%	$383	$18,750	$8,000	$10,509	$12,767
12	28163084	0.03%	$720	$75,000	$8,000	$20,457	$24,865
12	28163094	0.04%	$720	$75,000	$8,000	$20,386	$24,789
12	28165902	0.46%	$1,120	$0	$4,000	$25,524	$36,257
12	28165903	0.46%	$1,120	$0	$4,000	$25,524	$36,257
12	28166390	0.46%	$1,120	$0	$4,000	$25,524	$36,257
12	28166391	0.46%	$1,120	$0	$4,000	$25,524	$36,257
12	28685839	0.04%	$720	$75,000	$8,000	$20,288	$24,684
12	28685848	0.03%	$720	$75,000	$8,000	$20,449	$24,856
12	28685852	0.05%	$720	$75,000	$8,000	$19,988	$24,364

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES ON ISSUE 2.2

Job #	Asset Identifier	Failure Probability	Direct Cost ($)	Indirect Cost ($)		PV (2015 Cost of Deviation from Optimal) ($)	2012 Cost of Deviation from Optimal ($)
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12	28685953	0.04%	$720	$75,000	$8,000	$20,378	$24,780
12	28685956	29.79%	$2,233	$90,000	$0	$61,902	$0
12	28685957	39.42%	$2,233	$90,000	$0	$84,532	$0
12	28686154	0.04%	$720	$75,000	$8,000	$20,394	$24,797
12	28686166	0.05%	$720	$75,000	$8,000	$20,107	$24,491
12	28686174	0.05%	$720	$75,000	$8,000	$20,122	$24,506
12	28687485	0.03%	$720	$75,000	$8,000	$20,422	$24,828
12	28687493	0.05%	$720	$75,000	$8,000	$20,161	$24,548
12	28687499	24.73%	$2,233	$90,000	$0	$50,003	$0
12	28691790	22.10%	$2,233	$90,000	$0	$43,834	$0
12	28799559	0.00%	$720	$105,000	$8,000	$30,369	$36,324
12	28799561	0.06%	$2,233	$126,000	$0	$46,530	$59,912
12	28833261	0.00%	$720	$105,000	$8,000	$30,378	$36,330
12	28833269	0.00%	$720	$105,000	$8,000	$30,384	$36,333
12	28833270	0.08%	$2,233	$126,000	$0	$46,325	$60,334
12	30414230	0.34%	$383	$18,750	$8,000	$7,680	$9,921
12	30414254	0.31%	$383	$18,750	$8,000	$7,931	$10,176
12	30415665	0.21%	$2,233	$108,900	$0	$48,256	$66,158
12	30415682	0.10%	$2,233	$108,900	$0	$42,649	$55,964
12	30415690	0.07%	$2,233	$108,900	$0	$42,257	$54,766
12	30415781	0.11%	$2,233	$108,900	$0	$43,002	$56,760
12	30415811	0.41%	$2,233	$108,900	$0	$60,807	$86,236
12	30415894	0.09%	$2,233	$108,000	$0	$42,354	$55,406
12	30415926	0.16%	$2,233	$108,000	$0	$44,992	$60,538
12	30415935	0.11%	$2,233	$108,000	$0	$43,040	$56,927
12	30415974	0.16%	$2,233	$108,000	$0	$45,361	$61,231

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES ON ISSUE 2.2

Job #	Asset Identifier	Failure Probability	Direct Cost ($)	Indirect Cost ($)		PV (2015 Cost of Deviation from Optimal) ($)	2012 Cost of Deviation from Optimal ($)
				Customer Interruption Cost ($)	Other Indirect Cost ($)		
12	30416019	0.07%	$2,233	$108,000	$0	$41,965	$54,118
12	30416045	0.10%	$2,233	$108,000	$0	$42,437	$55,666
12	30416069	0.01%	$720	$90,000	$8,000	$24,194	$29,827
12	30420904	0.15%	$2,233	$108,900	$0	$44,637	$59,881
12	30444478	0.24%	$383	$18,750	$8,000	$8,615	$10,869
12	30444480	0.01%	$383	$18,750	$8,000	$11,274	$13,554
12	30444484	0.01%	$383	$18,750	$8,000	$11,275	$13,555
12	30447346	0.46%	$745	$0	$4,500	$1,297	$3,102
12	30447347	0.07%	$720	$75,150	$8,000	$21,168	$27,980
12	30447350	0.00%	$720	$105,000	$8,000	$30,383	$36,333
12	30447352	0.14%	$2,233	$108,900	$0	$44,257	$59,220
12	30447354	0.00%	$383	$0	$8,000	$4,276	$5,113
12	30451358	0.00%	$720	$75,150	$8,000	$25,512	$30,659
12	30451361	0.00%	$720	$75,150	$8,000	$25,594	$30,695
12	30451387	0.00%	$720	$105,000	$8,000	$30,090	$36,145
12	30451388	0.05%	$2,233	$126,000	$0	$46,923	$59,914
12	30561997	10.94%	$2,233	$90,000	$0	$17,584	$0
13	1171702	94.39%	$203	$135,790	$385	$368,838	$0
13	1171703	1.71%	$195	$134,301	$385	$3,629	$0
13	1171720	1.71%	$195	$137,133	$385	$3,756	$0
13	1171791	1.71%	$224	$215,512	$385	$6,803	$0
13	1171814	1.71%	$197	$13,896	$385	$4,968	$6,506
13	1171815	17.24%	$197	$13,896	$385	$4,986	$0
13	1172559	1.71%	$193	$41,666	$385	$173	$628
13	1172581	1.71%	$208	$134,231	$385	$3,399	$0
13	1172586	16.06%	$197	$41,666	$385	$17,137	$0

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES ON ISSUE 2.2

Job #	Asset Identifier	Failure Probability	Direct Cost ($)	Indirect Cost ($)		PV (2015 Cost of Deviation from Optimal) ($)	2012 Cost of Deviation from Optimal ($)
				Customer Interruption Cost ($)	Other Indirect Cost ($)		
13	1172588	36.74%	$203	$41,666	$385	$42,240	$0
13	1172728	22.59%	$199	$133,087	$385	$84,234	$0
13	1172771	22.59%	$266	$133,087	$385	$84,277	$0
13	1172773	22.59%	$218	$148,326	$385	$93,666	$0
13	1172781	5.47%	$209	$134,706	$385	$18,193	$0
13	1172805	1.71%	$197	$135,790	$385	$3,740	$0
13	1172811	1.71%	$195	$133,896	$385	$3,620	$0
13	1172812	100.00%	$210	$135,245	$385	$641,902	$0
13	1172814	7.23%	$210	$134,840	$385	$43,182	$0
13	1172823	27.32%	$197	$133,896	$385	$171,466	$0
13	1172825	7.23%	$228	$136,863	$385	$43,722	$0
13	1172828	1.71%	$197	$13,896	$385	$4,968	$6,506
13	1172830	1.71%	$195	$13,896	$385	$4,792	$6,291
13	1172832	17.24%	$193	$13,896	$385	$4,985	$0
13	1172837	1.71%	$205	$134,706	$385	$3,604	$0
13	1172839	4.48%	$199	$133,896	$385	$14,381	$0
13	1172844	0.01%	$201	$135,515	$385	$9,956	$13,087
13	1172902	1.71%	$193	$134,706	$385	$3,691	$0
13	1172906	0.03%	$281	$135,245	$385	$9,349	$12,521
13	1659801	9.54%	$408	$0	$4,500	$40,169	$0
13	1659802	9.54%	$408	$0	$4,500	$49,079	$0
13	1659803	9.54%	$408	$0	$4,500	$55,452	$0
13	1669178	0.22%	$270	$3,189,150	$8,000	$1,266,335	$1,562,650
13	1669527	0.13%	$270	$3,189,150	$8,000	$1,364,873	$1,667,227
13	1669652	0.11%	$383	$724,125	$8,000	$252,641	$308,654
13	1669714	0.13%	$270	$3,189,150	$8,000	$1,367,942	$1,670,484

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES ON ISSUE 2.2

Job #	Asset Identifier	Failure Probability	Direct Cost ($)	Indirect Cost ($)		PV (2015 Cost of Deviation from Optimal) ($)	2012 Cost of Deviation from Optimal ($)
				Customer Interruption Cost ($)	Other Indirect Cost ($)		
13	1669736	0.17%	$270	$3,189,150	$8,000	$1,325,135	$1,625,053
13	1669805	0.03%	$270	$3,189,150	$8,000	$1,484,533	$1,793,842
13	1669903	0.12%	$270	$3,189,150	$8,000	$1,380,704	$1,684,027
13	1670343	0.07%	$270	$3,189,150	$8,000	$1,435,142	$1,741,802
13	1670517	0.07%	$270	$3,189,150	$8,000	$1,434,334	$1,740,945
13	1670632	0.13%	$270	$3,189,150	$8,000	$1,370,365	$1,673,055
13	1671165	0.12%	$270	$3,189,150	$8,000	$1,380,865	$1,684,199
13	1671772	0.03%	$270	$3,189,150	$8,000	$1,484,533	$1,793,842
13	1671922	0.11%	$270	$3,189,150	$8,000	$1,386,681	$1,690,371
13	1671953	0.23%	$270	$3,189,150	$8,000	$1,255,028	$1,550,649
13	1672515	0.10%	$383	$724,125	$8,000	$254,296	$310,409
13	1672562	0.08%	$383	$241,500	$8,000	$91,041	$110,784
13	1672707	0.09%	$383	$241,500	$8,000	$89,968	$109,648
13	1672807	0.11%	$383	$241,500	$8,000	$88,289	$107,873
13	1673047	0.10%	$383	$724,125	$8,000	$254,480	$310,604
13	1673107	0.13%	$270	$3,189,150	$8,000	$1,362,611	$1,664,826
13	1673619	0.11%	$383	$241,500	$8,000	$88,733	$108,343
13	1673703	0.11%	$270	$3,189,150	$8,000	$1,386,196	$1,689,856
13	1673957	0.10%	$383	$241,500	$8,000	$89,721	$109,387
13	1674667	0.09%	$270	$3,189,150	$8,000	$1,415,273	$1,720,715
13	1674824	0.11%	$270	$3,189,150	$8,000	$1,388,134	$1,691,914
13	1674903	0.11%	$383	$724,125	$8,000	$252,531	$308,537
13	1675252	0.12%	$270	$3,189,150	$8,000	$1,383,450	$1,686,942
13	1675563	12.05%	$1,663	$3,614,370	$0	$697,086	$0
13	1675565	0.15%	$383	$724,125	$8,000	$241,573	$296,918
13	1675983	0.11%	$270	$3,189,150	$8,000	$1,387,327	$1,691,056

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES ON ISSUE 2.2

Job #	Asset Identifier	Failure Probability	Direct Cost ($)	Indirect Cost ($)		PV (2015 Cost of Deviation from Optimal) ($)	2012 Cost of Deviation from Optimal ($)
				Customer Interruption Cost ($)	Other Indirect Cost ($)		
13	1676686	0.11%	$270	$3,189,150	$8,000	$1,387,650	$1,691,399
13	1676913	0.11%	$270	$3,189,150	$8,000	$1,391,365	$1,695,342
13	1676916	0.13%	$270	$3,189,150	$8,000	$1,362,773	$1,664,998
13	1676924	0.10%	$270	$3,189,150	$8,000	$1,402,673	$1,707,343
13	1676952	0.25%	$270	$3,189,150	$8,000	$1,224,659	$1,518,419
13	1677274	9.00%	$1,746	$120,969	$0	$9,559	$0
13	1677488	19.18%	$1,746	$96,281	$0	$30,834	$0
13	1677882	8.82%	$1,746	$61,719	$0	$1,906	$0
13	1677921	5.68%	$2,233	$54,000	$0	$2,564	$0
13	1679300	5.71%	$1,746	$120,969	$0	$225	$1,929
13	1679635	15.19%	$2,233	$54,000	$0	$16,457	$0
13	1679932	33.29%	$1,746	$96,281	$0	$64,573	$0
13	1680566	0.27%	$383	$114,844	$8,000	$35,950	$45,080
13	1680758	10.96%	$1,746	$61,719	$0	$4,783	$0
13	1680808	9.88%	$1,746	$61,719	$0	$3,326	$0
13	1681705	40.18%	$1,746	$61,719	$0	$44,012	$0
13	1681990	0.56%	$383	$114,844	$8,000	$25,493	$33,924
13	1682080	0.02%	$383	$58,594	$8,000	$25,680	$31,032
13	1682103	27.25%	$2,233	$40,500	$0	$24,005	$0
13	1682137	31.45%	$2,233	$54,000	$0	$40,217	$0
13	1682839	18.76%	$2,233	$90,180	$0	$39,349	$0
13	1683042	0.02%	$383	$58,594	$8,000	$25,670	$31,021
13	1683095	9.53%	$1,746	$96,281	$0	$7,740	$0
13	1683360	7.07%	$2,233	$117,180	$0	$13,035	$0
13	1683527	75.15%	$1,746	$120,969	$0	$217,383	$0
13	1683919	26.91%	$1,746	$96,281	$0	$49,317	$0

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES ON ISSUE 2.2

Job #	Asset Identifier	Failure Probability	Direct Cost ($)	Indirect Cost ($)		PV (2015 Cost of Deviation from Optimal) ($)	2012 Cost of Deviation from Optimal ($)
				Customer Interruption Cost ($)	Other Indirect Cost ($)		
13	1684058	32.14%	$2,233	$54,000	$0	$41,225	$0
13	1684256	0.13%	$720	$112,500	$8,000	$27,942	$34,482
13	1684396	12.86%	$1,746	$61,719	$0	$7,333	$0
13	1684521	17.23%	$1,746	$96,281	$0	$26,156	$0
13	1684541	0.02%	$383	$91,406	$8,000	$37,839	$45,729
13	1684717	0.33%	$383	$114,844	$8,000	$33,482	$42,473
13	1685114	45.77%	$2,233	$90,180	$0	$108,488	$0
13	1685124	26.31%	$2,233	$90,180	$0	$58,677	$0
13	1685240	6.30%	$2,233	$27,000	$0	$497	$0
13	1685517	26.62%	$2,233	$27,000	$0	$13,527	$0
13	1685859	12.90%	$1,746	$96,281	$0	$15,813	$0
13	1686055	16.15%	$2,233	$27,000	$0	$6,815	$0
13	1686144	0.29%	$720	$97,650	$8,000	$19,333	$24,871
13	1687252	26.21%	$2,233	$135,000	$0	$90,431	$0
13	1687970	9.22%	$1,746	$657,083	$0	$85,415	$0
13	1688164	21.73%	$2,233	$27,000	$0	$10,393	$0
13	1688567	12.60%	$1,746	$120,969	$0	$20,873	$0
13	1688632	0.11%	$270	$3,189,150	$8,000	$1,391,204	$1,695,171
13	1689057	15.82%	$2,233	$40,500	$0	$11,988	$0
13	1689115	53.23%	$2,233	$40,500	$0	$51,315	$0
13	1689703	42.17%	$2,233	$54,000	$0	$55,875	$0
13	1689996	13.08%	$2,233	$54,000	$0	$13,381	$0
13	1690226	13.96%	$1,746	$61,719	$0	$8,811	$0
13	1691050	13.32%	$1,746	$657,083	$0	$167,720	$0
13	1691804	5.97%	$1,746	$61,719	$0	$329	$2,999
13	1692311	0.02%	$383	$58,594	$8,000	$25,674	$31,025

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES ON ISSUE 2.2

Job #	Asset Identifier	Failure Probability	Direct Cost ($)	Indirect Cost ($)		PV (2015 Cost of Deviation from Optimal) ($)	2012 Cost of Deviation from Optimal ($)
				Customer Interruption Cost ($)	Other Indirect Cost ($)		
13	1692514	75.73%	$2,233	$179,820	$0	$384,285	$0
13	1693013	8.33%	$2,233	$54,000	$0	$6,434	$0
13	1693563	9.67%	$2,233	$54,000	$0	$8,394	$0
13	1693688	0.02%	$383	$58,594	$8,000	$25,681	$31,033
13	1693763	0.67%	$383	$114,844	$8,000	$22,436	$30,596
13	1694541	0.16%	$720	$45,000	$8,000	$14,522	$17,945
13	1694728	25.17%	$1,746	$120,969	$0	$60,355	$0
13	1695349	6.27%	$2,233	$27,000	$0	$482	$0
13	1695363	16.05%	$1,746	$61,719	$0	$11,612	$0
13	1695628	49.48%	$1,746	$120,969	$0	$136,725	$0
13	1695687	18.68%	$2,233	$40,500	$0	$14,995	$0
13	1695717	43.49%	$2,233	$40,500	$0	$41,070	$0
13	1695798	0.02%	$383	$91,406	$8,000	$37,838	$45,727
13	1696273	84.18%	$1,746	$96,281	$0	$186,319	$0
13	1696846	0.02%	$383	$58,594	$8,000	$25,683	$31,035
13	1697121	35.32%	$2,233	$40,500	$0	$32,488	$0
13	1697305	27.00%	$2,233	$54,000	$0	$33,715	$0
13	1697555	46.78%	$1,746	$96,281	$0	$96,854	$0
13	1697572	36.89%	$1,746	$120,969	$0	$97,185	$0
13	1698364	23.73%	$1,746	$96,281	$0	$41,715	$0
13	1698712	14.78%	$2,233	$54,000	$0	$15,854	$0
13	1700395	0.02%	$383	$58,594	$8,000	$25,678	$31,030
13	1700448	3.19%	$2,233	$40,500	$0	$587	$2,138
13	1700554	5.52%	$2,233	$27,000	$0	$111	$218
13	1700626	9.00%	$1,746	$96,281	$0	$6,480	$0
13	1700636	33.02%	$2,233	$54,000	$0	$42,506	$0

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES ON ISSUE 2.2

Job #	Asset Identifier	Failure Probability	Direct Cost ($)	Indirect Cost ($)		PV (2015 Cost of Deviation from Optimal) ($)	2012 Cost of Deviation from Optimal ($)
				Customer Interruption Cost ($)	Other Indirect Cost ($)		
13	1701239	20.61%	$1,746	$657,083	$0	$314,442	$0
13	1701890	2.02%	$720	$375,000	$8,000	$761	$922
13	1702364	0.02%	$383	$114,844	$8,000	$46,547	$56,250
13	1702648	9.54%	$2,233	$90,000	$0	$15,704	$0
13	1702719	2.75%	$2,233	$54,000	$0	$882	$2,900
13	1703022	0.45%	$383	$114,844	$8,000	$29,145	$37,857
13	1703075	0.07%	$720	$97,650	$8,000	$26,995	$32,955
13	1703513	43.40%	$2,233	$135,000	$0	$157,895	$0
13	1704079	0.97%	$1,746	$96,281	$0	$40,947	$53,874
13	1704099	6.24%	$2,233	$27,000	$0	$458	$0
13	1704129	14.34%	$2,233	$20,160	$0	$3,230	$0
13	1704999	24.64%	$1,746	$120,969	$0	$58,710	$0
13	1705514	0.02%	$383	$58,594	$8,000	$25,676	$31,027
13	1705529	3.95%	$1,746	$120,969	$0	$4,042	$11,304
13	1706282	44.84%	$2,233	$40,500	$0	$42,490	$0
13	1706360	13.59%	$1,746	$61,719	$0	$8,307	$0
13	1706468	36.87%	$2,233	$54,000	$0	$48,125	$0
13	1706838	19.24%	$2,233	$54,000	$0	$22,376	$0
13	1706933	16.14%	$1,746	$657,083	$0	$224,495	$0
13	1707230	2.95%	$1,746	$120,969	$0	$11,733	$21,881
13	1707865	11.14%	$2,233	$54,000	$0	$10,538	$0
13	1708053	13.69%	$1,746	$657,083	$0	$175,178	$0
13	1708646	0.82%	$720	$22,500	$8,000	$5,757	$7,986
13	1710082	0.02%	$383	$114,844	$8,000	$46,537	$56,240
13	1710160	0.08%	$720	$112,500	$8,000	$29,766	$36,405
13	1710266	1.01%	$1,746	$96,281	$0	$39,813	$52,645

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES ON ISSUE 2.2

Job #	Asset Identifier	Failure Probability	Direct Cost ($)	Indirect Cost ($)		PV (2015 Cost of Deviation from Optimal) ($)	2012 Cost of Deviation from Optimal ($)
				Customer Interruption Cost ($)	Other Indirect Cost ($)		
13	1710276	19.37%	$1,746	$120,969	$0	$42,156	$0
13	1710836	20.73%	$1,746	$96,281	$0	$34,539	$0
13	1713265	0.47%	$720	$33,750	$8,000	$8,787	$11,543
13	1742914	11.16%	$540	$0	$4,000	$1,134	$0
13	1742925	11.16%	$540	$0	$2,000	$3,023	$0
13	1742926	11.16%	$540	$0	$4,000	$3,579	$0
13	1742930	11.16%	$540	$0	$2,000	$1,487	$0
13	1742956	11.16%	$540	$0	$4,000	$12,110	$0
13	1742957	11.16%	$540	$0	$4,000	$1,134	$0
13	1742961	11.16%	$540	$0	$4,000	$20,808	$0
13	1742962	11.16%	$540	$0	$4,000	$1,521	$0
13	1742963	11.16%	$540	$0	$2,000	$1,487	$0
13	1743257	3.74%	$540	$0	$4,000	$5,066	$0
13	1743258	13.27%	$540	$0	$4,000	$27,166	$0
13	1743268	11.16%	$540	$0	$2,000	$5,619	$0
13	1743269	11.16%	$540	$0	$2,000	$1,487	$0
13	1743271	11.16%	$540	$0	$2,000	$11,959	$0
13	1743272	11.16%	$540	$0	$2,000	$5,619	$0
13	1743273	11.16%	$540	$0	$2,000	$3,023	$0
13	1743275	11.16%	$540	$0	$2,000	$3,023	$0
13	1743277	11.16%	$540	$0	$2,000	$1,487	$0
13	1743278	11.16%	$540	$0	$2,000	$206	$0
13	1743343	13.27%	$540	$0	$4,000	$26,377	$0
13	1743344	1.42%	$540	$0	$4,000	$463	$0
13	1743345	2.00%	$540	$0	$4,000	$1,834	$0
13	1743346	13.27%	$540	$0	$4,000	$27,166	$0

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES ON ISSUE 2.2

Job #	Asset Identifier	Failure Probability	Direct Cost ($)	Indirect Cost ($)		PV (2015 Cost of Deviation from Optimal) ($)	2012 Cost of Deviation from Optimal ($)
				Customer Interruption Cost ($)	Other Indirect Cost ($)		
13	1743347	13.27%	$540	$0	$4,000	$27,166	$0
13	1743348	13.27%	$540	$0	$4,000	$53,206	$0
13	1743349	13.27%	$540	$0	$4,000	$53,206	$0
13	1743350	13.27%	$540	$0	$4,000	$53,206	$0
13	1743351	13.27%	$540	$0	$4,000	$41,990	$0
13	1743352	13.27%	$540	$0	$4,000	$41,990	$0
13	1743353	13.27%	$540	$0	$4,000	$42,862	$0
13	1743354	13.27%	$540	$0	$4,000	$41,990	$0
13	1743355	13.27%	$540	$0	$4,000	$54,124	$0
13	1743381	13.27%	$540	$0	$4,000	$26,377	$0
13	1743382	13.27%	$540	$0	$4,000	$26,377	$0
13	1743395	11.16%	$540	$0	$2,000	$11,959	$0
13	1743396	11.16%	$540	$0	$2,000	$5,619	$0
13	1743397	58.32%	$540	$0	$4,000	$0	$0
13	1743398	58.32%	$540	$0	$4,000	$0	$0
13	1743399	11.16%	$540	$0	$4,000	$1,521	$0
13	1743400	11.16%	$540	$0	$4,000	$1,134	$0
13	1743404	11.16%	$540	$0	$4,000	$1,134	$0
13	1743409	11.16%	$540	$0	$4,000	$3,579	$0
13	1743410	0.02%	$540	$0	$2,000	$19,255	$24,366
13	1743412	11.16%	$540	$0	$2,000	$1,487	$0
13	1743413	11.16%	$540	$0	$4,000	$1,521	$0
13	1743416	11.16%	$540	$0	$4,000	$1,594	$0
13	1743417	11.16%	$540	$0	$2,000	$5,619	$0
13	1743419	11.16%	$540	$0	$2,000	$5,619	$0
13	1743420	11.16%	$540	$0	$2,000	$3,023	$0

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES ON ISSUE 2.2

Job #	Asset Identifier	Failure Probability	Direct Cost ($)	Indirect Cost ($)		PV (2015 Cost of Deviation from Optimal) ($)	2012 Cost of Deviation from Optimal ($)
				Customer Interruption Cost ($)	Other Indirect Cost ($)		
13	1743423	11.16%	$540	$0	$2,000	$1,487	$0
13	1743424	11.16%	$540	$0	$2,000	$5,619	$0
13	1743425	11.16%	$540	$0	$2,000	$5,619	$0
13	1743429	11.16%	$540	$0	$2,000	$3,023	$0
13	1743430	11.16%	$540	$0	$4,000	$1,521	$0
13	1743431	11.16%	$540	$0	$4,000	$3,579	$0
13	1743455	11.16%	$540	$0	$2,000	$5,619	$0
13	1743461	11.16%	$540	$0	$2,000	$5,619	$0
13	1743802	3.74%	$540	$0	$4,000	$9,425	$0
13	1743803	13.27%	$540	$0	$4,000	$53,206	$0
13	1743804	1.19%	$540	$0	$2,000	$2,116	$0
13	1743805	4.18%	$540	$0	$2,000	$15,087	$0
13	1743806	3.74%	$540	$0	$4,000	$9,425	$0
13	1743807	13.27%	$540	$0	$4,000	$42,862	$0
13	1743808	3.74%	$540	$0	$4,000	$9,425	$0
13	1743809	13.27%	$540	$0	$4,000	$42,862	$0
13	1743810	13.27%	$540	$0	$4,000	$41,990	$0
13	1743811	13.27%	$540	$0	$4,000	$54,124	$0
13	1743812	2.00%	$540	$0	$4,000	$4,944	$0
13	1743813	1.60%	$540	$0	$4,000	$4,076	$0
13	1743814	4.18%	$540	$0	$2,000	$11,514	$0
13	1743815	1.60%	$540	$0	$4,000	$1,850	$0
13	1743816	13.27%	$540	$0	$4,000	$53,206	$0
13	1743817	13.27%	$540	$0	$4,000	$53,206	$0
13	1743818	0.20%	$540	$0	$4,000	$2,911	$6,710
13	1743819	0.20%	$540	$0	$4,000	$2,911	$6,710

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES ON ISSUE 2.2

Job #	Asset Identifier	Failure Probability	Direct Cost ($)	Indirect Cost ($)		PV (2015 Cost of Deviation from Optimal) ($)	2012 Cost of Deviation from Optimal ($)
				Customer Interruption Cost ($)	Other Indirect Cost ($)		
13	1743856	2.00%	$540	$0	$4,000	$4,944	$0
13	28131513	0.69%	$383	$91,406	$8,000	$18,185	$24,849
13	28131514	0.54%	$383	$91,406	$8,000	$21,609	$28,566
13	28685054	4.17%	$2,233	$90,000	$0	$2,005	$0
13	28685515	0.85%	$1,746	$120,969	$0	$53,922	$70,150
13	28685521	0.79%	$1,746	$120,969	$0	$56,389	$72,812
13	28685533	8.53%	$1,746	$120,969	$0	$8,096	$0
13	28685571	0.90%	$1,746	$120,969	$0	$52,168	$68,252
13	28685579	0.84%	$1,746	$120,969	$0	$54,554	$70,832
13	28685586	12.93%	$1,746	$120,969	$0	$21,910	$0
13	28685600	0.85%	$1,746	$61,719	$0	$30,342	$39,253
13	28685607	0.03%	$383	$58,594	$8,000	$25,515	$30,860
13	28685608	0.03%	$383	$58,594	$8,000	$25,562	$30,908
13	28711281	0.08%	$720	$45,000	$8,000	$15,788	$19,266
13	28711692	0.80%	$1,746	$96,281	$0	$45,569	$58,861
13	28711693	0.82%	$1,746	$96,281	$0	$45,054	$58,308
13	28771213	7.52%	$1,746	$61,719	$0	$430	$589
13	28797933	0.11%	$720	$22,500	$8,000	$10,932	$13,352
13	28797941	0.10%	$720	$22,500	$8,000	$11,030	$13,452
13	28797946	0.10%	$720	$22,500	$8,000	$11,026	$13,448
13	30457283	0.00%	$222	$375,249	$385	$10,556	$14,792
13	30457299	2.85%	$330	$2,795,107	$5,000	$837,151	$0
13	30529931	0.09%	$720	$33,750	$8,000	$13,437	$16,388
13	30529943	0.10%	$720	$33,750	$8,000	$13,225	$16,168
13	30529952	0.10%	$720	$33,750	$8,000	$13,205	$16,147
13	30530198	2.60%	$2,233	$54,000	$0	$1,258	$3,485

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES ON ISSUE 2.2

Job #	Asset Identifier	Failure Probability	Direct Cost ($)	Indirect Cost ($)		PV (2015 Cost of Deviation from Optimal) ($)	2012 Cost of Deviation from Optimal ($)
				Customer Interruption Cost ($)	Other Indirect Cost ($)		
13	30530209	3.67%	$2,233	$54,000	$0	$20	$669
13	30530220	2.48%	$2,233	$54,000	$0	$1,613	$4,004
13	30530230	2.70%	$2,233	$54,000	$0	$1,061	$3,149
13	30530703	4.36%	$2,233	$27,000	$0	$141	$1,142
13	30530844	0.08%	$720	$45,000	$8,000	$15,841	$19,321
13	30538926	3.18%	$2,233	$27,000	$0	$1,192	$2,876
13	30538928	3.40%	$2,233	$27,000	$0	$900	$2,456
13	30538930	2.54%	$2,233	$27,000	$0	$2,368	$4,430
13	30539601	0.10%	$720	$45,000	$8,000	$15,433	$18,896
13	30539691	0.10%	$720	$45,000	$8,000	$15,496	$18,961
13	30539695	0.10%	$720	$45,000	$8,000	$15,455	$18,919
13	30540005	0.11%	$720	$22,500	$8,000	$10,866	$13,284
13	30540123	0.09%	$720	$22,500	$8,000	$11,107	$13,532
13	30564598	4.22%	$2,233	$27,000	$0	$254	$1,334
13	30564632	0.13%	$720	$45,000	$8,000	$15,026	$18,471
13	30564634	0.20%	$720	$45,000	$8,000	$13,849	$17,243
13	30564639	11.85%	$2,233	$54,000	$0	$11,579	$0
13	30564645	3.41%	$2,233	$54,000	$0	$0	$1,126
13	30565084	0.13%	$720	$33,750	$8,000	$12,877	$15,807
13	30566029	3.38%	$2,233	$90,000	$0	$202	$636
13	30566030	2.42%	$2,233	$90,000	$0	$1,289	$4,217
13	30566038	3.34%	$2,233	$90,000	$0	$166	$702
13	30569247	0.09%	$720	$33,750	$8,000	$13,435	$16,386
13	30569400	0.11%	$720	$45,000	$8,000	$15,337	$18,795
14	13618635	1.07%	$1,746	$49,375	$0	$26,355	$36,595
14	13622162	0.45%	$383	$37,500	$8,000	$10,560	$14,271

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES ON ISSUE 2.2

Job #	Asset Identifier	Failure Probability	Direct Cost ($)	Indirect Cost ($)		PV (2015 Cost of Deviation from Optimal) ($)	2012 Cost of Deviation from Optimal ($)
				Customer Interruption Cost ($)	Other Indirect Cost ($)		
14	13622729	0.11%	$383	$46,875	$8,000	$18,228	$23,020
14	13623739	0.01%	$383	$46,875	$8,000	$22,393	$26,882
14	13624678	1.06%	$1,746	$44,438	$0	$25,440	$35,066
14	13624861	0.04%	$214	$1,647,188	$8,000	$889,550	$1,073,147
14	13626088	0.01%	$214	$1,647,188	$8,000	$917,348	$1,101,598
14	13626106	0.05%	$214	$1,647,188	$8,000	$876,424	$1,059,863
14	13626229	0.00%	$214	$1,647,188	$8,000	$929,932	$1,114,070
14	13627023	0.00%	$214	$1,647,188	$8,000	$929,815	$1,113,953
14	13627370	0.01%	$214	$1,647,188	$8,000	$923,496	$1,107,691
14	13628585	0.01%	$383	$46,875	$8,000	$22,499	$26,981
14	13631797	0.00%	$214	$1,647,188	$8,000	$930,093	$1,114,229
14	13632498	0.41%	$1,746	$49,375	$0	$31,273	$40,208
14	13632681	0.00%	$214	$1,647,188	$8,000	$932,473	$1,116,840
14	13634201	3.50%	$1,746	$29,625	$0	$30,028	$44,140
14	13634291	0.17%	$1,746	$49,375	$0	$35,704	$44,161
14	13635450	0.29%	$383	$32,813	$8,000	$11,349	$14,970
14	13636579	0.01%	$214	$1,647,188	$8,000	$928,382	$1,112,533
14	13638548	0.01%	$383	$32,813	$8,000	$16,843	$20,222
14	13640347	0.00%	$214	$1,647,188	$8,000	$929,676	$1,113,815
14	13643788	0.04%	$214	$1,647,188	$8,000	$892,028	$1,075,654
14	13645701	0.01%	$214	$1,647,188	$8,000	$916,076	$1,100,337
14	13645950	3.68%	$1,746	$39,500	$0	$27,146	$42,117
14	13648822	0.57%	$383	$42,188	$8,000	$10,059	$14,063
14	13650220	11.58%	$1,746	$39,500	$0	$45,816	$78,687
14	13653416	0.12%	$383	$46,875	$8,000	$17,889	$22,712
14	13653435	0.14%	$383	$46,875	$8,000	$17,436	$22,304

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES ON ISSUE 2.2

Job #	Asset Identifier	Failure Probability	Direct Cost ($)	Indirect Cost ($)		PV (2015 Cost of Deviation from Optimal) ($)	2012 Cost of Deviation from Optimal ($)
				Customer Interruption Cost ($)	Other Indirect Cost ($)		
14	13653803	0.23%	$383	$42,188	$8,000	$14,514	$19,221
14	14075762	1.85%	$580	$7,800	$2,800	$383	$0
14	14075764	1.85%	$580	$7,800	$2,800	$383	$0
14	14075880	2.63%	$816	$1,379,873	$2,600	$100,269	$0
14	14075901	1.85%	$580	$4,680	$2,800	$110	$0
14	14076041	2.55%	$580	$5,460	$2,800	$321	$0
14	14076042	2.55%	$580	$7,020	$2,800	$538	$0
14	14076043	2.55%	$580	$6,240	$2,800	$473	$0
14	14076060	1.27%	$580	$7,800	$2,800	$73	$0
14	14076088	1.85%	$580	$7,020	$2,800	$222	$0
14	14076089	1.85%	$580	$6,240	$2,800	$185	$0
14	14076092	1.85%	$580	$5,460	$2,800	$147	$0
14	14119638	3.46%	$540	$0	$4,000	$3,778	$0
14	14119639	3.46%	$540	$0	$4,000	$3,778	$0
14	14119640	3.46%	$540	$0	$4,000	$3,778	$0
14	14119641	3.46%	$540	$0	$4,000	$3,778	$0
14	14119642	3.46%	$540	$0	$4,000	$3,778	$0
14	14119643	3.46%	$540	$0	$4,000	$3,778	$0
14	14119644	3.46%	$540	$0	$4,000	$3,778	$0
14	14119654	3.46%	$540	$0	$4,000	$3,778	$0
14	14119655	3.46%	$540	$0	$4,000	$3,778	$0
14	14119656	3.46%	$540	$0	$4,000	$3,778	$0
14	14119657	3.46%	$540	$0	$4,000	$3,778	$0
14	14119658	3.46%	$540	$0	$4,000	$3,778	$0
14	14119659	3.46%	$540	$0	$4,000	$3,778	$0
14	14119661	3.46%	$540	$0	$4,000	$3,778	$0

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES ON ISSUE 2.2

Job #	Asset Identifier	Failure Probability	Direct Cost ($)	Indirect Cost ($)		PV (2015 Cost of Deviation from Optimal) ($)	2012 Cost of Deviation from Optimal ($)
				Customer Interruption Cost ($)	Other Indirect Cost ($)		
14	14119685	3.46%	$540	$0	$4,000	$3,778	$0
14	14119686	3.46%	$540	$0	$4,000	$3,778	$0
14	14119687	3.46%	$540	$0	$4,000	$3,778	$0
14	14119698	3.46%	$540	$0	$4,000	$3,778	$0
14	14119711	3.46%	$540	$0	$4,000	$3,778	$0
14	14120085	2.68%	$540	$0	$4,000	$1,892	$0
14	14120086	2.92%	$540	$0	$4,000	$677	$0
14	14120087	2.92%	$540	$0	$4,000	$1,122	$0
14	14120088	3.74%	$540	$0	$4,000	$3,078	$0
14	14120090	0.55%	$540	$0	$4,000	$2,627	$5,384
14	14120093	2.92%	$540	$0	$4,000	$1,122	$0
14	14120094	2.68%	$540	$0	$4,000	$1,048	$0
14	14120095	3.18%	$540	$0	$4,000	$1,027	$0
14	14120096	3.18%	$540	$0	$4,000	$1,027	$0
14	14120097	2.21%	$540	$0	$4,000	$135	$216
14	14120098	2.68%	$540	$0	$4,000	$1,892	$0
14	14120099	3.46%	$540	$0	$4,000	$2,472	$0
14	14120100	2.68%	$540	$0	$4,000	$2,323	$0
14	14120101	2.68%	$540	$0	$4,000	$2,323	$0
14	14120102	1.79%	$540	$0	$4,000	$92	$446
14	14120103	1.42%	$540	$0	$4,000	$139	$1,300
14	14120104	1.08%	$540	$0	$4,000	$945	$2,820
14	14120105	2.68%	$540	$0	$4,000	$1,467	$0
14	14120106	2.68%	$540	$0	$4,000	$1,892	$0
14	14120107	3.46%	$540	$0	$4,000	$2,472	$0
14	14120165	3.18%	$540	$0	$4,000	$3,274	$0

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES ON ISSUE 2.2

Job #	Asset Identifier	Failure Probability	Direct Cost ($)	Indirect Cost ($)		PV (2015 Cost of Deviation from Optimal) ($)	2012 Cost of Deviation from Optimal ($)
				Customer Interruption Cost ($)	Other Indirect Cost ($)		
14	14120285	4.03%	$540	$0	$4,000	$4,179	$0
14	14120286	4.03%	$540	$0	$4,000	$4,179	$0
14	14120287	4.03%	$540	$0	$4,000	$4,179	$0
14	14120288	4.03%	$540	$0	$4,000	$3,519	$0
14	14120289	4.03%	$540	$0	$4,000	$3,519	$0
14	14120290	4.03%	$540	$0	$4,000	$4,179	$0
14	14120291	4.03%	$540	$0	$4,000	$3,519	$0
14	14120292	0.17%	$540	$0	$2,000	$4,335	$6,947
14	14120293	3.46%	$540	$0	$4,000	$2,098	$0
14	14120294	3.46%	$540	$0	$4,000	$2,098	$0
14	14120295	3.46%	$540	$0	$4,000	$2,098	$0
14	14120296	3.46%	$540	$0	$4,000	$2,098	$0
14	14120297	3.46%	$540	$0	$4,000	$2,098	$0
14	14120298	3.46%	$540	$0	$4,000	$2,098	$0
14	14120299	4.03%	$540	$0	$4,000	$2,220	$0
14	14120300	4.03%	$540	$0	$4,000	$2,866	$0
14	14120308	4.03%	$540	$0	$4,000	$2,220	$0
14	14120309	4.03%	$540	$0	$4,000	$2,220	$0
14	14120310	4.03%	$540	$0	$4,000	$2,220	$0
14	14120331	4.03%	$540	$0	$4,000	$2,220	$0
14	14120332	4.03%	$540	$0	$4,000	$2,220	$0
14	14120333	4.03%	$540	$0	$4,000	$3,519	$0
14	14120334	4.03%	$540	$0	$4,000	$3,519	$0
14	14120335	0.14%	$540	$0	$4,000	$4,242	$6,952
14	14120336	4.03%	$540	$0	$4,000	$4,179	$0
14	14120362	3.46%	$540	$0	$4,000	$3,212	$0

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES ON ISSUE 2.2

Job #	Asset Identifier	Failure Probability	Direct Cost ($)	Indirect Cost ($)		PV (2015 Cost of Deviation from Optimal) ($)	2012 Cost of Deviation from Optimal ($)
				Customer Interruption Cost ($)	Other Indirect Cost ($)		
14	14120363	3.46%	$540	$0	$4,000	$3,212	$0
14	14120364	3.46%	$540	$0	$4,000	$3,212	$0
14	14120365	4.03%	$540	$0	$4,000	$3,519	$0
14	14120366	4.03%	$540	$0	$4,000	$4,179	$0
14	14120557	1.79%	$540	$0	$4,000	$92	$446
14	28721880	0.45%	$383	$32,813	$8,000	$9,657	$13,038
14	28721885	0.10%	$383	$32,813	$8,000	$14,255	$17,904
14	28721892	0.00%	$383	$32,813	$8,000	$17,021	$20,405
14	28721894	0.01%	$383	$32,813	$8,000	$16,928	$20,319
14	28721896	0.11%	$383	$32,813	$8,000	$14,083	$17,755
14	28721900	0.09%	$383	$32,813	$8,000	$14,364	$17,999
14	28721902	0.08%	$383	$32,813	$8,000	$14,668	$18,268
14	28721906	0.15%	$383	$37,500	$8,000	$14,687	$18,828
14	28722091	0.16%	$383	$37,500	$8,000	$14,480	$18,650
14	28722113	0.16%	$383	$37,500	$8,000	$14,494	$18,662
14	28722171	0.13%	$383	$42,188	$8,000	$16,343	$20,815
14	28722175	0.12%	$383	$42,188	$8,000	$16,626	$21,067
14	28722186	0.10%	$383	$42,188	$8,000	$17,046	$21,445
14	28722188	0.15%	$383	$42,188	$8,000	$15,876	$20,400
14	28722208	0.01%	$383	$42,188	$8,000	$20,653	$24,770
14	28722213	0.15%	$383	$42,188	$8,000	$15,866	$20,391
14	28722217	0.15%	$383	$46,875	$8,000	$17,072	$21,976
14	28722223	0.16%	$383	$46,875	$8,000	$16,999	$21,912
14	28722227	0.12%	$383	$46,875	$8,000	$17,925	$22,744
14	28725104	2.00%	$1,746	$49,375	$0	$24,452	$36,516
14	28750883	6.95%	$1,746	$49,375	$0	$27,806	$49,662

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES ON ISSUE 2.2

Job #	Asset Identifier	Failure Probability	Direct Cost ($)	Indirect Cost ($)		PV (2015 Cost of Deviation from Optimal) ($)	2012 Cost of Deviation from Optimal ($)
				Customer Interruption Cost ($)	Other Indirect Cost ($)		
14	28757740	2.44%	$1,746	$34,563	$0	$25,572	$37,376
14	28757812	1.68%	$1,746	$34,563	$0	$24,034	$34,007
14	28757819	0.15%	$383	$32,813	$8,000	$13,331	$16,851
14	28757824	0.25%	$383	$32,813	$8,000	$11,852	$15,446
14	28757828	0.27%	$383	$32,813	$8,000	$11,630	$15,236
14	28757854	3.23%	$1,746	$29,625	$0	$29,032	$42,462
14	28757862	2.79%	$1,746	$29,625	$0	$27,518	$39,830
14	28757865	5.92%	$1,746	$29,625	$0	$39,183	$59,474
14	28757870	1.35%	$1,746	$29,625	$0	$23,143	$31,786
14	28757874	2.43%	$1,746	$29,625	$0	$26,223	$37,607
14	28758341	2.03%	$1,746	$44,438	$0	$24,380	$36,064
14	28758343	3.77%	$1,746	$44,438	$0	$25,692	$41,079
14	28758350	4.14%	$1,746	$44,438	$0	$26,302	$42,462
14	28758354	0.15%	$383	$42,188	$8,000	$16,089	$20,331
14	28758358	2.87%	$1,746	$44,438	$0	$24,844	$38,322
14	28758362	2.74%	$1,746	$44,438	$0	$24,690	$37,891
14	28758366	2.75%	$1,746	$44,438	$0	$24,704	$37,930
14	28758368	2.98%	$1,746	$44,438	$0	$24,970	$38,676
14	28758373	2.69%	$1,746	$44,438	$0	$24,632	$37,728
14	28758386	4.70%	$1,746	$39,500	$0	$29,301	$46,591
14	28758392	2.47%	$1,746	$39,500	$0	$25,041	$37,277
14	28758394	2.29%	$1,746	$39,500	$0	$24,757	$36,598
14	28758401	8.37%	$1,746	$39,500	$0	$37,931	$63,516
14	28758405	1.64%	$1,746	$39,500	$0	$24,254	$34,615
14	28758409	4.12%	$1,746	$39,500	$0	$27,961	$43,940
14	28758413	2.55%	$1,746	$39,500	$0	$25,169	$37,584

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES ON ISSUE 2.2

Job #	Asset Identifier	Failure Probability	Direct Cost ($)	Indirect Cost ($)		PV (2015 Cost of Deviation from Optimal) ($)	2012 Cost of Deviation from Optimal ($)
				Customer Interruption Cost ($)	Other Indirect Cost ($)		
14	28791457	1.80%	$816	$1,379,873	$2,600	$67,383	$0
14	28833554	0.00%	$383	$46,875	$8,000	$22,529	$27,010
14	28833679	0.21%	$383	$46,875	$8,000	$16,009	$21,033
14	28833683	0.01%	$383	$42,188	$8,000	$20,672	$24,789
14	28833871	0.11%	$383	$37,500	$8,000	$15,313	$19,376
14	30308282	2.80%	$1,746	$49,375	$0	$24,093	$37,754
14	30308483	3.24%	$1,746	$49,375	$0	$24,152	$38,668
14	30308484	3.68%	$1,746	$49,375	$0	$24,542	$39,932
14	30308583	5.07%	$1,746	$49,375	$0	$25,578	$43,726
14	30308623	0.14%	$1,746	$49,375	$0	$36,664	$45,052
14	30308740	2.80%	$1,746	$49,375	$0	$24,091	$37,747
14	30308788	3.06%	$1,746	$49,375	$0	$24,243	$38,419
14	30308861	1.60%	$1,746	$49,375	$0	$24,881	$36,160
14	30308935	6.17%	$1,746	$49,375	$0	$27,063	$47,376
14	30308992	4.07%	$1,746	$49,375	$0	$24,693	$40,858
14	30308993	2.59%	$1,746	$49,375	$0	$24,179	$37,419
14	30309100	2.05%	$1,746	$49,375	$0	$24,308	$36,469
14	30309294	4.16%	$1,746	$49,375	$0	$24,796	$41,139
14	30309342	0.13%	$1,746	$49,375	$0	$36,788	$45,167
14	30309354	2.80%	$1,746	$49,375	$0	$24,090	$37,742
14	30309416	4.07%	$1,746	$49,375	$0	$24,693	$40,858
14	30310273	3.31%	$1,746	$49,375	$0	$24,219	$38,887
14	30310364	3.35%	$1,746	$49,375	$0	$24,254	$38,999
14	30311633	2.94%	$1,746	$49,375	$0	$24,172	$38,102
14	30416498	0.15%	$383	$32,813	$8,000	$13,282	$16,805
14	30416500	2.72%	$1,746	$29,625	$0	$27,252	$39,374

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES ON ISSUE 2.2

Job #	Asset Identifier	Failure Probability	Direct Cost ($)	Indirect Cost ($)		PV (2015 Cost of Deviation from Optimal) ($)	2012 Cost of Deviation from Optimal ($)
				Customer Interruption Cost ($)	Other Indirect Cost ($)		
14	30416518	3.28%	$1,746	$49,375	$0	$24,188	$38,784
14	30419032	0.13%	$383	$46,875	$8,000	$17,525	$22,383
14	30419041	0.14%	$383	$46,875	$8,000	$17,463	$22,327
15	1170399	0.60%	$197	$65,341	$385	$2,445	$3,951
15	1170401	0.60%	$201	$65,746	$385	$2,422	$3,924
15	1170430	0.60%	$199	$65,341	$385	$2,552	$4,091
15	1170432	0.60%	$199	$65,341	$385	$2,552	$4,091
15	1170433	0.60%	$201	$65,746	$385	$2,422	$3,924
15	1170520	0.60%	$216	$67,100	$385	$3,675	$5,592
15	1170523	0.60%	$213	$66,015	$385	$3,229	$3,773
15	1170536	0.60%	$216	$67,100	$385	$3,373	$3,954
15	1170537	0.60%	$274	$64,397	$385	$3,104	$3,572
15	1170637	0.60%	$207	$65,341	$385	$3,121	$4,847
15	1170644	36.74%	$193	$65,746	$385	$71,573	$0
15	1170661	0.60%	$216	$67,100	$385	$3,373	$3,954
15	1170662	0.60%	$216	$67,100	$385	$3,373	$3,954
15	1170664	0.60%	$205	$65,341	$385	$2,445	$3,951
15	1170666	0.60%	$197	$65,341	$385	$2,445	$3,951
15	1170667	0.60%	$193	$65,746	$385	$2,422	$3,924
15	1170668	0.60%	$199	$65,341	$385	$2,552	$4,091
15	1170669	0.60%	$193	$65,746	$385	$2,422	$3,924
15	1170707	36.74%	$201	$64,937	$385	$70,681	$0
15	1170709	7.23%	$201	$128,255	$385	$25,322	$0
15	1170715	36.74%	$201	$65,746	$385	$71,582	$0
15	1171140	0.60%	$201	$73,562	$385	$1,972	$3,387
15	1171227	0.60%	$226	$116,392	$385	$902	$2,116

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES ON ISSUE 2.2

Job #	Asset Identifier	Failure Probability	Direct Cost ($)	Indirect Cost ($)		PV (2015 Cost of Deviation from Optimal) ($)	2012 Cost of Deviation from Optimal ($)
				Customer Interruption Cost ($)	Other Indirect Cost ($)		
15	1171232	0.60%	$214	$95,569	$385	$1,982	$3,586
15	1187059	0.60%	$214	$70,191	$385	$3,024	$4,774
15	1220246	2.52%	$458	$0	$5,000	$17,597	$0
15	1669583	0.02%	$214	$1,344,591	$8,000	$749,099	$900,226
15	1669626	0.01%	$214	$1,344,591	$8,000	$752,446	$903,542
15	1669748	0.71%	$1,592	$1,498,258	$0	$799,249	$1,070,211
15	1670004	1.07%	$1,592	$1,498,258	$0	$608,421	$864,072
15	1670037	0.02%	$214	$1,344,591	$8,000	$748,602	$899,734
15	1670803	0.02%	$214	$1,344,591	$8,000	$748,419	$899,552
15	1671033	0.02%	$214	$1,344,591	$8,000	$749,569	$900,692
15	1671112	0.02%	$214	$1,344,591	$8,000	$746,091	$897,247
15	1671486	0.01%	$214	$1,344,591	$8,000	$753,309	$904,397
15	1671550	0.02%	$214	$1,344,591	$8,000	$744,103	$895,278
15	1672462	0.02%	$214	$1,344,591	$8,000	$749,622	$900,744
15	1673357	0.02%	$214	$1,344,591	$8,000	$748,549	$899,682
15	1673490	0.02%	$214	$1,344,591	$8,000	$748,314	$899,449
15	1674355	0.02%	$214	$1,344,591	$8,000	$748,759	$899,889
15	1674507	0.02%	$214	$1,344,591	$8,000	$746,536	$897,687
15	1674879	0.02%	$214	$1,344,591	$8,000	$741,174	$892,376
15	1676193	0.02%	$214	$1,344,591	$8,000	$743,972	$895,148
15	1676842	0.02%	$214	$1,344,591	$8,000	$747,660	$898,801
15	1677283	1.26%	$2,233	$54,000	$0	$8,454	$13,977
15	1677538	8.94%	$2,233	$40,500	$0	$1,758	$8,388
15	1679557	5.75%	$2,233	$54,000	$0	$708	$5,482
15	1679803	7.64%	$2,233	$90,180	$0	$3,103	$0
15	1680791	2.03%	$2,233	$90,180	$0	$4,330	$10,544

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES ON ISSUE 2.2

Job #	Asset Identifier	Failure Probability	Direct Cost ($)	Indirect Cost ($)		PV (2015 Cost of Deviation from Optimal) ($)	2012 Cost of Deviation from Optimal ($)
				Customer Interruption Cost ($)	Other Indirect Cost ($)		
15	1680991	5.56%	$1,746	$630,519	$0	$9,706	$5,392
15	1681330	0.09%	$720	$33,750	$8,000	$13,520	$16,759
15	1681578	0.09%	$383	$16,406	$8,000	$10,051	$12,398
15	1683012	19.57%	$1,746	$630,519	$0	$270,486	$0
15	1684225	5.10%	$2,233	$40,500	$0	$3,077	$8,854
15	1685612	0.12%	$383	$16,406	$8,000	$9,950	$12,375
15	1685737	4.60%	$2,233	$40,500	$0	$3,270	$8,935
15	1685783	2.78%	$2,233	$54,000	$0	$3,726	$8,997
15	1685969	2.14%	$2,233	$54,000	$0	$5,175	$10,553
15	1686498	16.35%	$2,233	$90,180	$0	$16,576	$0
15	1687286	18.90%	$1,746	$248,554	$0	$78,725	$0
15	1687843	20.29%	$1,746	$248,554	$0	$87,323	$0
15	1688109	4.78%	$2,233	$40,500	$0	$3,200	$8,906
15	1688401	1.21%	$2,233	$27,000	$0	$8,804	$13,086
15	1688801	14.88%	$2,233	$54,000	$0	$923	$3,149
15	1690959	10.58%	$2,233	$40,500	$0	$1,085	$8,080
15	1691071	0.06%	$383	$23,438	$8,000	$12,644	$15,456
15	1692124	0.05%	$383	$23,438	$8,000	$12,712	$15,508
15	1692149	0.10%	$383	$598,594	$8,000	$199,681	$248,125
15	1693715	0.10%	$383	$16,406	$8,000	$10,018	$12,387
15	1694680	0.03%	$383	$598,594	$8,000	$227,078	$274,689
15	1695424	0.10%	$383	$23,438	$8,000	$12,289	$15,198
15	1697421	6.03%	$2,233	$40,500	$0	$2,553	$8,536
15	1697729	0.10%	$720	$33,750	$8,000	$13,343	$16,614
15	1697788	0.05%	$383	$16,406	$8,000	$10,286	$12,517
15	1697897	3.62%	$2,233	$54,000	$0	$2,352	$7,482

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES ON ISSUE 2.2

Job #	Asset Identifier	Failure Probability	Direct Cost ($)	Indirect Cost ($)		PV (2015 Cost of Deviation from Optimal) ($)	2012 Cost of Deviation from Optimal ($)
				Customer Interruption Cost ($)	Other Indirect Cost ($)		
15	1698809	0.24%	$720	$75,150	$8,000	$16,949	$22,531
15	1699441	0.06%	$383	$41,438	$8,000	$18,889	$23,107
15	1699502	0.20%	$383	$598,594	$8,000	$166,174	$214,550
15	1699529	0.26%	$2,233	$40,500	$0	$41,453	$51,369
15	1702062	6.21%	$2,233	$90,180	$0	$1,277	$1,049
15	1702349	0.03%	$383	$598,594	$8,000	$225,934	$273,559
15	1702666	0.21%	$720	$45,000	$8,000	$13,646	$17,737
15	1702696	0.10%	$383	$41,438	$8,000	$17,984	$22,312
15	1703567	0.09%	$383	$41,438	$8,000	$18,162	$22,466
15	1703808	0.03%	$383	$598,594	$8,000	$226,242	$273,864
15	1705022	9.15%	$1,746	$630,519	$0	$75,350	$0
15	1705906	0.11%	$383	$23,438	$8,000	$12,207	$15,143
15	1707799	7.40%	$1,746	$630,519	$0	$42,681	$0
15	1708865	1.97%	$2,233	$40,500	$0	$6,377	$11,453
15	1709914	0.17%	$720	$45,000	$8,000	$14,201	$18,189
15	1710320	0.13%	$383	$23,438	$8,000	$12,018	$15,024
15	1712103	7.75%	$1,746	$248,554	$0	$9,618	$0
15	1713179	0.10%	$383	$23,438	$8,000	$12,240	$15,165
15	1713320	0.11%	$383	$41,438	$8,000	$17,833	$22,182
15	1742376	3.91%	$540	$0	$4,000	$8,962	$14,094
15	1742378	3.91%	$540	$0	$4,000	$8,962	$14,094
15	1742399	3.91%	$540	$0	$4,000	$14,111	$21,529
15	1742400	3.91%	$540	$0	$4,000	$16,932	$26,992
15	1742403	3.91%	$540	$0	$4,000	$16,932	$26,992
15	1742408	3.91%	$8,016	$3,750	$1,600	$58,282	$2,113
15	1742409	3.91%	$540	$0	$4,000	$16,932	$26,992

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES ON ISSUE 2.2

Job #	Asset Identifier	Failure Probability	Direct Cost ($)	Indirect Cost ($)		PV (2015 Cost of Deviation from Optimal) ($)	2012 Cost of Deviation from Optimal ($)
				Customer Interruption Cost ($)	Other Indirect Cost ($)		
15	1742432	3.91%	$540	$0	$4,000	$16,932	$26,992
15	1742433	3.91%	$540	$0	$2,000	$6,365	$9,529
15	1742434	3.91%	$540	$0	$4,000	$8,962	$14,094
15	1742435	3.91%	$540	$0	$2,000	$4,333	$7,178
15	1742436	3.91%	$540	$0	$2,000	$1,723	$4,233
15	1742438	3.91%	$540	$0	$4,000	$14,111	$21,529
15	1742439	3.91%	$540	$0	$4,000	$8,962	$14,094
15	1742440	3.91%	$540	$0	$4,000	$8,962	$14,094
15	1742441	3.91%	$540	$0	$4,000	$14,111	$21,529
15	1742442	3.91%	$540	$0	$4,000	$8,962	$14,094
15	1742443	3.91%	$540	$0	$4,000	$8,962	$14,094
15	1742451	3.91%	$540	$0	$4,000	$14,111	$21,529
15	1742460	3.91%	$540	$0	$4,000	$14,111	$21,529
15	1742694	3.91%	$540	$0	$4,000	$14,111	$21,529
15	1742695	58.32%	$540	$0	$4,000	$0	$0
15	1742696	3.91%	$540	$0	$4,000	$2,115	$7,553
15	1742711	3.91%	$540	$0	$4,000	$7,247	$15,079
15	1742716	4.65%	$540	$0	$4,000	$4,354	$0
15	1742717	4.65%	$540	$0	$4,000	$4,354	$0
15	1742718	4.65%	$540	$0	$4,000	$4,354	$0
15	1742720	4.65%	$540	$0	$4,000	$1,525	$0
15	1742721	3.91%	$540	$0	$2,000	$83,319	$0
15	1742733	58.32%	$540	$0	$4,000	$0	$0
15	1742743	58.32%	$540	$0	$4,000	$0	$0
15	1742778	4.65%	$540	$0	$4,000	$466	$0
15	1742779	4.65%	$540	$0	$4,000	$466	$0

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES ON ISSUE 2.2

Job #	Asset Identifier	Failure Probability	Direct Cost ($)	Indirect Cost ($)		PV (2015 Cost of Deviation from Optimal) ($)	2012 Cost of Deviation from Optimal ($)
				Customer Interruption Cost ($)	Other Indirect Cost ($)		
15	1742780	4.65%	$540	$0	$4,000	$1,525	$0
15	1742781	4.65%	$540	$0	$4,000	$1,525	$0
15	1747928	3.91%	$540	$0	$4,000	$8,962	$14,094
15	28132304	0.07%	$383	$41,438	$8,000	$18,713	$22,951
15	28132305	0.07%	$383	$41,438	$8,000	$18,661	$22,905
15	30490743	0.01%	$720	$16,800	$8,000	$10,934	$13,139
15	30490745	0.01%	$720	$16,800	$8,000	$10,934	$13,139
15	30490799	2.27%	$2,233	$20,160	$0	$8,494	$13,317
15	30490807	0.01%	$720	$16,800	$8,000	$10,920	$13,131
15	30490855	0.01%	$720	$22,500	$8,000	$12,294	$14,775
15	30490857	0.02%	$720	$22,500	$8,000	$12,240	$14,734
16	1670754	0.00%	$720	$744,000	$8,000	$188,084	$226,003
16	1675711	0.00%	$720	$744,000	$8,000	$188,251	$225,405
16	1675995	0.00%	$720	$744,000	$8,000	$187,500	$224,712
16	1683798	1.02%	$1,746	$86,406	$0	$59,022	$84,923
16	1684082	1.39%	$1,746	$271,563	$0	$73,431	$124,113
16	1689076	0.01%	$383	$82,031	$8,000	$39,083	$46,952
16	1689669	0.00%	$383	$82,031	$8,000	$39,322	$47,140
16	1690286	0.01%	$720	$33,750	$8,000	$15,254	$18,338
16	1694617	0.34%	$1,746	$271,563	$0	$121,282	$164,653
16	1700596	0.04%	$720	$75,150	$8,000	$23,349	$29,033
16	1705468	1.23%	$1,746	$271,563	$0	$77,171	$126,729
16	1706215	0.93%	$2,233	$0	$0	$68,867	$83,105
16	1707059	0.00%	$383	$82,031	$8,000	$39,248	$47,081
16	1708858	0.06%	$720	$450,000	$8,000	$90,753	$116,511
16	1709094	0.03%	$720	$225,000	$8,000	$55,497	$68,654

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES ON ISSUE 2.2

Job #	Asset Identifier	Failure Probability	Direct Cost ($)	Indirect Cost ($)		PV (2015 Cost of Deviation from Optimal) ($)	2012 Cost of Deviation from Optimal ($)
				Customer Interruption Cost ($)	Other Indirect Cost ($)		
16	2285723	0.02%	$383	$4,688	$8,000	$6,796	$8,252
16	2286552	0.01%	$383	$4,688	$8,000	$6,427	$7,749
16	2286924	0.06%	$1,746	$86,406	$0	$99,393	$133,939
16	2286992	0.02%	$383	$4,688	$8,000	$6,811	$8,271
16	28043166	0.00%	$1,746	$86,406	$0	$155,181	$188,820
16	28043168	0.00%	$2,233	$0	$0	$13,954	$16,665
16	28043302	0.00%	$383	$82,031	$8,000	$39,993	$47,857
16	28043311	0.00%	$383	$82,031	$8,000	$39,992	$47,855
16	28043314	0.00%	$383	$82,031	$8,000	$39,974	$47,811
16	28158967	0.01%	$383	$4,688	$8,000	$6,509	$7,861
16	28726841	0.00%	$720	$25,050	$8,000	$10,418	$12,467
16	28726868	0.04%	$2,233	$30,060	$0	$16,672	$20,483
16	28726910	0.84%	$2,233	$30,060	$0	$43,289	$57,894
16	28825057	0.00%	$383	$82,031	$8,000	$40,336	$48,631
16	28825138	0.03%	$1,746	$86,406	$0	$77,057	$101,419
16	30343388	0.35%	$1,746	$4,938	$0	$28,689	$35,270
16	30343395	0.37%	$1,746	$4,938	$0	$29,814	$36,665
16	30343602	1.03%	$2,233	$30,060	$0	$50,593	$67,913
16	30343672	0.00%	$720	$0	$8,000	$4,212	$5,038
16	30343673	0.00%	$720	$25,050	$8,000	$10,418	$12,466
16	30538993	0.00%	$720	$25,050	$8,000	$10,418	$12,467
16	30538996	0.04%	$2,233	$30,060	$0	$16,609	$20,344
17	1196710	0.26%	$214	$166,393	$385	$3,130	$5,377
17	1196715	1.34%	$202	$153,447	$385	$3,553	$0
17	1665053	2.40%	$776	$2,598,858	$5,000	$169,144	$0
17	1665058	1.04%	$408	$0	$4,500	$1,433	$0

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES ON ISSUE 2.2

Job #	Asset Identifier	Failure Probability	Direct Cost ($)	Indirect Cost ($)		PV (2015 Cost of Deviation from Optimal) ($)	2012 Cost of Deviation from Optimal ($)
				Customer Interruption Cost ($)	Other Indirect Cost ($)		
17	1665059	1.04%	$408	$0	$4,500	$1,433	$0
17	1665060	0.34%	$408	$0	$4,500	$0	$1,317
17	1665061	0.34%	$408	$0	$4,500	$0	$1,317
17	1665062	0.34%	$408	$0	$4,500	$0	$1,317
17	1665063	0.81%	$745	$0	$4,500	$2,330	$0
17	1677146	2.52%	$1,746	$113,464	$0	$102,019	$141,914
17	1678804	0.13%	$1,746	$128,375	$0	$80,084	$101,304
17	1679464	0.03%	$1,746	$128,375	$0	$180,637	$235,418
17	1679833	0.03%	$383	$225,000	$8,000	$88,328	$108,129
17	1680028	0.01%	$1,746	$128,375	$0	$113,346	$143,729
17	1680723	2.50%	$1,746	$237,000	$0	$25,022	$60,117
17	1680785	1.26%	$2,233	$261,000	$0	$29,910	$57,982
17	1681744	0.49%	$2,233	$261,000	$0	$47,485	$73,059
17	1681977	0.03%	$383	$225,000	$8,000	$88,216	$108,030
17	1682015	1.58%	$2,233	$202,500	$0	$13,184	$28,058
17	1683361	0.18%	$1,746	$254,479	$0	$133,227	$175,109
17	1684328	13.77%	$2,233	$261,000	$0	$42,726	$0
17	1685428	0.01%	$2,233	$261,000	$0	$122,332	$162,511
17	1685645	0.44%	$2,233	$261,000	$0	$56,890	$87,416
17	1685957	0.01%	$2,233	$261,000	$0	$109,136	$142,697
17	1686311	1.80%	$2,233	$261,000	$0	$9,383	$24,701
17	1686884	0.02%	$1,746	$138,250	$0	$154,480	$200,234
17	1686983	0.02%	$383	$225,000	$8,000	$90,072	$109,674
17	1687439	2.29%	$1,746	$148,125	$0	$27,251	$55,009
17	1687477	0.91%	$1,592	$3,312,270	$0	$1,815,390	$2,433,933
17	1687520	0.01%	$1,746	$128,375	$0	$123,017	$157,180

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES ON ISSUE 2.2

Job #	Asset Identifier	Failure Probability	Direct Cost ($)	Indirect Cost ($)		PV (2015 Cost of Deviation from Optimal) ($)	2012 Cost of Deviation from Optimal ($)
				Customer Interruption Cost ($)	Other Indirect Cost ($)		
17	1687829	3.63%	$2,233	$261,000	$0	$0	$8,531
17	1688446	7.70%	$2,233	$202,500	$0	$2,385	$3,891
17	1688906	0.01%	$1,746	$128,375	$0	$128,135	$164,245
17	1689263	13.06%	$1,746	$138,250	$0	$0	$19,264
17	1689868	0.00%	$720	$217,500	$8,000	$58,115	$69,553
17	1690069	2.28%	$2,233	$202,500	$0	$7,538	$21,355
17	1690538	4.40%	$1,746	$138,250	$0	$13,902	$34,505
17	1690582	25.06%	$1,592	$3,312,270	$0	$1,961,064	$0
17	1690638	0.03%	$1,746	$128,375	$0	$191,070	$249,445
17	1690957	4.77%	$1,746	$138,250	$0	$12,095	$32,642
17	1691205	0.00%	$720	$168,750	$8,000	$45,957	$55,025
17	1691538	1.06%	$2,233	$261,000	$0	$32,529	$59,655
17	1691612	2.42%	$1,746	$138,250	$0	$25,811	$46,709
17	1692257	0.01%	$2,233	$261,000	$0	$114,891	$151,437
17	1692305	0.02%	$1,746	$138,250	$0	$148,933	$192,694
17	1692645	0.00%	$720	$217,500	$8,000	$58,121	$69,558
17	1693022	0.01%	$2,233	$261,000	$0	$111,598	$146,404
17	1693047	4.67%	$2,233	$261,000	$0	$1,503	$4,611
17	1693255	4.86%	$1,746	$138,250	$0	$11,888	$32,421
17	1693415	0.00%	$720	$217,500	$8,000	$57,898	$69,359
17	1694288	0.03%	$1,746	$128,375	$0	$207,452	$271,569
17	1694948	0.00%	$383	$131,250	$8,000	$56,362	$67,429
17	1695201	0.91%	$1,746	$138,250	$0	$64,578	$95,482
17	1695219	0.95%	$1,746	$254,479	$0	$99,299	$156,333
17	1695350	3.13%	$2,233	$202,500	$0	$3,454	$15,983
17	1695399	15.65%	$1,746	$113,464	$0	$25,868	$0

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES ON ISSUE 2.2

Job #	Asset Identifier	Failure Probability	Direct Cost ($)	Indirect Cost ($)		PV (2015 Cost of Deviation from Optimal) ($)	2012 Cost of Deviation from Optimal ($)
				Customer Interruption Cost ($)	Other Indirect Cost ($)		
17	1698234	2.69%	$2,233	$202,500	$0	$5,320	$18,513
17	1698583	1.30%	$2,233	$261,000	$0	$29,610	$57,889
17	1698935	2.18%	$1,746	$138,250	$0	$28,154	$49,086
17	1699257	0.02%	$720	$168,750	$8,000	$42,058	$51,329
17	1700336	1.44%	$1,592	$3,312,270	$0	$579,707	$1,150,453
17	1700805	4.20%	$2,233	$261,000	$0	$659	$5,665
17	1700924	0.00%	$720	$168,750	$8,000	$46,023	$55,083
17	1700934	0.98%	$1,746	$254,479	$0	$99,250	$156,778
17	1701758	0.05%	$383	$131,250	$8,000	$47,725	$59,349
17	1702223	8.57%	$1,746	$254,479	$0	$22,521	$0
17	1702474	0.00%	$383	$121,875	$8,000	$53,730	$65,133
17	1702737	0.39%	$2,233	$261,000	$0	$58,017	$87,460
17	1703623	0.00%	$383	$131,250	$8,000	$54,960	$68,169
17	1704447	0.00%	$383	$131,250	$8,000	$56,363	$67,430
17	1705103	0.01%	$2,233	$261,000	$0	$105,087	$136,206
17	1705823	0.00%	$720	$33,750	$8,000	$15,301	$18,343
17	1707867	0.00%	$383	$225,000	$8,000	$95,113	$114,168
17	1708218	5.54%	$2,233	$261,000	$0	$4,404	$2,207
17	1708224	0.90%	$1,746	$237,000	$0	$60,710	$96,723
17	1709044	0.15%	$720	$168,750	$8,000	$27,832	$38,099
17	1709334	0.01%	$1,746	$128,375	$0	$115,603	$146,860
17	1709844	0.07%	$720	$168,750	$8,000	$33,702	$43,528
17	1710011	51.74%	$1,592	$3,312,270	$0	$4,772,990	$0
17	1710489	0.15%	$2,233	$261,000	$0	$69,580	$94,439
17	1710578	0.06%	$720	$168,750	$8,000	$35,472	$45,174
17	1710715	0.01%	$1,746	$128,375	$0	$116,287	$147,810

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES ON ISSUE 2.2

Job #	Asset Identifier	Failure Probability	Direct Cost ($)	Indirect Cost ($)		PV (2015 Cost of Deviation from Optimal) ($)	2012 Cost of Deviation from Optimal ($)
				Customer Interruption Cost ($)	Other Indirect Cost ($)		
17	1712593	0.02%	$383	$225,000	$8,000	$91,034	$110,529
17	1752541	3.64%	$540	$0	$4,000	$8,933	$17,457
17	1752543	2.21%	$540	$0	$4,000	$5,159	$0
17	1752545	4.33%	$540	$0	$4,000	$13,715	$0
17	1752546	4.65%	$540	$0	$4,000	$14,970	$0
17	1752548	4.65%	$540	$0	$4,000	$20,148	$0
17	1752549	4.03%	$540	$0	$4,000	$17,948	$0
17	1752551	4.33%	$540	$0	$4,000	$17,798	$0
17	1752598	3.39%	$540	$0	$4,000	$10,848	$16,434
17	1752599	1.60%	$540	$0	$4,000	$3,559	$0
17	1752600	4.03%	$540	$0	$4,000	$16,990	$0
17	1752601	3.74%	$540	$0	$4,000	$15,490	$0
17	1752602	4.03%	$540	$0	$4,000	$17,948	$0
17	1752603	3.74%	$540	$0	$4,000	$15,490	$0
17	1752604	4.03%	$540	$0	$4,000	$16,297	$0
17	1752605	2.21%	$540	$0	$4,000	$7,219	$0
17	1752608	3.74%	$540	$0	$4,000	$11,329	$0
17	1752610	3.74%	$540	$0	$4,000	$11,329	$0
17	1752611	0.20%	$540	$0	$4,000	$1,764	$4,641
17	1752612	1.42%	$540	$0	$4,000	$2,769	$0
17	1752613	1.60%	$540	$0	$4,000	$2,631	$0
17	1752614	3.46%	$540	$0	$4,000	$10,198	$0
17	1752616	4.65%	$540	$0	$4,000	$20,148	$0
17	1752634	3.74%	$540	$0	$4,000	$14,268	$0
17	1752635	4.65%	$540	$0	$4,000	$19,349	$0
17	1752636	4.03%	$540	$0	$4,000	$16,297	$0

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES ON ISSUE 2.2

Job #	Asset Identifier	Failure Probability	Direct Cost ($)	Indirect Cost ($)		PV (2015 Cost of Deviation from Optimal) ($)	2012 Cost of Deviation from Optimal ($)
				Customer Interruption Cost ($)	Other Indirect Cost ($)		
17	1752638	0.23%	$540	$0	$2,000	$1,235	$3,911
17	1752673	4.03%	$540	$0	$4,000	$16,297	$0
17	1752674	4.03%	$540	$0	$4,000	$16,990	$0
17	1752675	2.21%	$540	$0	$4,000	$6,468	$0
17	1752676	1.42%	$540	$0	$4,000	$2,684	$0
17	1752677	4.03%	$540	$0	$4,000	$15,841	$0
17	1752678	4.03%	$540	$0	$4,000	$15,841	$0
17	1752679	3.74%	$540	$0	$4,000	$13,565	$0
17	1752680	4.03%	$540	$0	$4,000	$15,841	$0
17	1752681	4.03%	$540	$0	$4,000	$17,948	$0
17	1752683	4.03%	$540	$0	$4,000	$17,245	$0
17	1752684	4.03%	$540	$0	$4,000	$16,990	$0
17	1752685	4.03%	$540	$0	$4,000	$17,245	$0
17	1752686	4.03%	$540	$0	$4,000	$17,948	$0
17	1752687	4.03%	$540	$0	$4,000	$16,990	$0
17	1752688	4.03%	$540	$0	$4,000	$16,990	$0
17	1752718	3.46%	$540	$0	$4,000	$14,043	$0
17	1752720	3.74%	$540	$0	$4,000	$13,565	$0
17	2286643	0.03%	$2,233	$261,000	$0	$181,379	$247,716
17	2286797	0.38%	$2,233	$261,000	$0	$51,425	$75,270
17	7774896	0.00%	$720	$217,500	$8,000	$58,034	$69,481
17	28126558	0.03%	$1,746	$138,250	$0	$100,136	$121,739
17	28126559	0.97%	$1,746	$138,250	$0	$64,580	$96,152
17	28126989	1.52%	$1,746	$138,250	$0	$64,901	$102,320
17	28127074	0.00%	$720	$168,750	$8,000	$45,975	$55,041
17	28127077	0.00%	$720	$168,750	$8,000	$45,984	$55,049

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES ON ISSUE 2.2

Job #	Asset Identifier	Failure Probability	Direct Cost ($)	Indirect Cost ($)		PV (2015 Cost of Deviation from Optimal) ($)	2012 Cost of Deviation from Optimal ($)
				Customer Interruption Cost ($)	Other Indirect Cost ($)		
17	28127345	0.00%	$720	$217,500	$8,000	$58,105	$69,543
17	28127346	0.93%	$2,233	$261,000	$0	$34,794	$61,288
17	28127381	0.00%	$720	$217,500	$8,000	$58,078	$69,519
17	28127383	0.00%	$720	$217,500	$8,000	$58,086	$69,527
17	28127409	0.00%	$720	$168,750	$8,000	$45,954	$55,022
17	28127433	0.08%	$383	$131,250	$8,000	$43,982	$55,897
17	28131623	3.30%	$1,746	$138,250	$0	$18,712	$39,479
17	28689901	0.31%	$2,233	$202,500	$0	$46,946	$66,189
17	28689902	1.87%	$2,233	$202,500	$0	$29,119	$58,416
17	28689908	0.00%	$720	$168,750	$8,000	$46,019	$55,079
17	28748694	0.00%	$383	$121,875	$8,000	$53,211	$63,766
17	28748702	0.00%	$383	$121,875	$8,000	$53,228	$63,843
17	28748705	0.01%	$1,746	$128,375	$0	$112,665	$142,733
17	28748708	0.01%	$1,746	$128,375	$0	$136,021	$174,970
17	28793061	0.01%	$1,746	$128,375	$0	$108,086	$136,253
17	30401185	0.10%	$720	$168,750	$8,000	$30,820	$40,856
17	30401188	0.00%	$720	$168,750	$8,000	$46,036	$55,095
17	30401198	0.00%	$720	$168,750	$8,000	$45,931	$55,002
17	30401206	0.00%	$720	$168,750	$8,000	$45,986	$55,051
17	30401208	0.00%	$720	$168,750	$8,000	$45,974	$55,040
17	30438335	3.33%	$2,233	$202,500	$0	$3,048	$15,279
17	30440836	1.23%	$2,233	$202,500	$0	$17,885	$33,281
17	30489642	0.00%	$383	$140,625	$8,000	$65,227	$79,033
17	30492970	41.12%	$1,746	$254,479	$0	$270,777	$0
18	1220946	6.75%	$214	$0	$5,000	$1,035,144	$0
18	1666292	5.63%	$745	$0	$4,500	$1,166	$0

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES ON ISSUE 2.2

Job #	Asset Identifier	Failure Probability	Direct Cost ($)	Indirect Cost ($)		PV (2015 Cost of Deviation from Optimal) ($)	2012 Cost of Deviation from Optimal ($)
				Customer Interruption Cost ($)	Other Indirect Cost ($)		
18	1677054	0.00%	$416	$2,037,287	$8,000	$754,823	$909,861
18	1678609	0.69%	$416	$2,037,287	$8,000	$279,597	$415,885
18	1681221	0.01%	$416	$2,037,287	$8,000	$748,549	$904,754
18	1681518	0.20%	$214	$2,503,856	$8,000	$1,144,511	$1,417,730
18	1682130	0.02%	$416	$2,037,287	$8,000	$707,035	$872,028
18	1682346	32.93%	$1,746	$330,813	$0	$274,372	$0
18	1684130	0.35%	$383	$314,063	$8,000	$79,600	$103,795
18	1684780	2.06%	$214	$2,503,856	$8,000	$204,614	$389,446
18	1685772	1.82%	$214	$2,503,856	$8,000	$259,399	$456,589
18	1687362	0.87%	$383	$314,063	$8,000	$42,055	$63,193
18	1687453	8.03%	$1,592	$2,790,011	$0	$136,118	$0
18	1687673	0.14%	$383	$82,031	$8,000	$30,280	$37,419
18	1690723	0.15%	$383	$937,500	$8,000	$300,559	$372,821
18	1691861	0.36%	$214	$2,503,856	$8,000	$968,881	$1,234,217
18	1692376	0.51%	$214	$2,503,856	$8,000	$842,466	$1,103,582
18	1692829	0.02%	$416	$2,037,287	$8,000	$710,183	$874,420
18	1696474	6.94%	$2,233	$27,000	$0	$0	$1,429
18	1697754	0.70%	$383	$82,031	$8,000	$16,230	$22,928
18	1699266	0.14%	$383	$82,031	$8,000	$30,015	$37,151
18	1701961	0.16%	$214	$2,503,856	$8,000	$1,196,326	$1,470,922
18	1702177	0.06%	$416	$2,037,287	$8,000	$636,694	$824,866
18	1702626	10.73%	$1,746	$86,406	$0	$2,347	$803
18	1703054	0.14%	$383	$82,031	$8,000	$30,276	$37,414
18	1704820	1.33%	$383	$82,031	$8,000	$10,456	$17,047
18	1704997	0.74%	$383	$82,031	$8,000	$15,504	$22,156
18	1705622	0.73%	$383	$82,031	$8,000	$17,724	$24,937

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES ON ISSUE 2.2

Job #	Asset Identifier	Failure Probability	Direct Cost ($)	Indirect Cost ($)		PV (2015 Cost of Deviation from Optimal) ($)	2012 Cost of Deviation from Optimal ($)
				Customer Interruption Cost ($)	Other Indirect Cost ($)		
18	1705976	20.54%	$1,746	$86,406	$0	$31,419	$0
18	1712133	1.23%	$383	$375,000	$8,000	$31,094	$53,100
18	1712342	5.91%	$2,233	$18,000	$0	$9,809	$16,128
18	1749623	7.07%	$540	$0	$2,000	$306	$1,368
18	2285836	2.27%	$214	$2,503,856	$8,000	$165,226	$338,850
18	2285859	1.31%	$214	$2,503,856	$8,000	$415,944	$639,581
18	2285952	0.07%	$416	$2,037,287	$8,000	$627,972	$820,474
18	2285958	1.02%	$214	$2,503,856	$8,000	$537,667	$775,713
18	2286253	47.03%	$1,746	$987,500	$0	$1,283,080	$0
18	2286303	1.18%	$214	$2,503,856	$8,000	$466,633	$696,919
18	2286497	2.05%	$214	$2,503,856	$8,000	$205,323	$390,366
18	2286566	1.30%	$383	$314,063	$8,000	$24,531	$42,893
18	2286627	1.24%	$214	$2,503,856	$8,000	$439,874	$666,907
18	2286700	1.66%	$214	$2,503,856	$8,000	$301,470	$507,146
18	2286775	0.06%	$416	$2,037,287	$8,000	$633,304	$822,980
18	2286820	0.45%	$214	$2,503,856	$8,000	$898,652	$1,162,645
18	2286987	0.53%	$214	$2,503,856	$8,000	$829,654	$1,090,044
18	2287124	1.98%	$214	$2,503,856	$8,000	$222,260	$410,994
18	8689949	0.55%	$383	$937,500	$8,000	$172,283	$237,547
18	8689970	0.38%	$383	$187,594	$8,000	$48,799	$63,853
18	28733462	0.61%	$416	$2,037,287	$8,000	$310,832	$449,665
18	30313223	0.01%	$416	$2,037,287	$8,000	$732,048	$891,499
18	30316179	0.01%	$416	$2,037,287	$8,000	$732,810	$892,111
18	30316201	0.01%	$416	$2,037,287	$8,000	$726,147	$886,838
18	30554326	0.24%	$383	$937,500	$8,000	$263,866	$334,761
19	1178812	7.23%	$198	$98,976	$385	$22,212	$0

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES ON ISSUE 2.2

Job #	Asset Identifier	Failure Probability	Direct Cost ($)	Indirect Cost ($)		PV (2015 Cost of Deviation from Optimal) ($)	2012 Cost of Deviation from Optimal ($)
				Customer Interruption Cost ($)	Other Indirect Cost ($)		
19	1178813	7.23%	$196	$1,753	$385	$2,453	$3,992
19	1178814	7.23%	$202	$1,753	$385	$2,830	$4,500
19	1178924	5.47%	$254	$22,387	$385	$2,215	$0
19	1178956	0.14%	$260	$22,387	$385	$8,968	$11,169
19	1179075	7.23%	$198	$22,387	$385	$3,603	$0
19	1179077	7.23%	$189	$22,387	$385	$3,639	$0
19	1179141	0.14%	$211	$22,387	$385	$9,685	$12,028
19	1179205	94.39%	$208	$22,387	$385	$73,166	$0
19	1179206	7.23%	$258	$22,387	$385	$3,617	$0
19	1179271	0.14%	$256	$22,387	$385	$8,145	$10,181
19	1179277	0.14%	$258	$22,387	$385	$8,339	$10,413
19	1660983	0.43%	$580	$5,070	$2,800	$285	$522
19	1670740	0.00%	$720	$48,750	$8,000	$16,369	$19,576
19	1675890	0.00%	$383	$389,063	$8,000	$161,076	$192,996
19	1677507	0.35%	$1,746	$409,813	$0	$142,221	$207,066
19	1680952	0.01%	$720	$7,500	$8,000	$6,791	$8,219
19	1683258	0.00%	$720	$45,000	$8,000	$18,161	$21,889
19	1683471	0.03%	$214	$2,038,509	$8,000	$1,074,876	$1,317,433
19	1687403	0.41%	$2,233	$40,500	$0	$28,754	$40,018
19	1691957	0.60%	$1,746	$14,813	$0	$106,754	$134,147
19	1692012	0.55%	$1,746	$409,813	$0	$116,335	$182,731
19	1694568	0.01%	$383	$389,063	$8,000	$152,851	$185,118
19	1697878	0.00%	$720	$7,500	$8,000	$6,310	$7,575
19	1699219	0.11%	$1,746	$14,813	$0	$31,616	$39,227
19	1700780	0.01%	$720	$0	$8,000	$5,046	$6,086
19	1702407	0.28%	$1,746	$14,813	$0	$56,275	$70,449

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES ON ISSUE 2.2

Job #	Asset Identifier	Failure Probability	Direct Cost ($)	Indirect Cost ($)		PV (2015 Cost of Deviation from Optimal) ($)	2012 Cost of Deviation from Optimal ($)
				Customer Interruption Cost ($)	Other Indirect Cost ($)		
19	1707520	0.14%	$1,746	$14,813	$0	$35,975	$44,752
19	1745446	1.08%	$540	$0	$4,000	$2,187	$3,886
19	1745474	1.08%	$540	$0	$4,000	$2,187	$3,886
19	1745475	1.08%	$540	$0	$4,000	$2,187	$3,886
19	1745504	2.73%	$9,542	$15,750	$1,600	$20,128	$15,767
19	1745505	0.91%	$540	$0	$2,000	$15,329	$21,006
19	1745521	0.91%	$8,016	$3,750	$1,600	$18,168	$8,519
19	1745538	0.91%	$8,016	$5,625	$1,600	$17,349	$9,656
19	1745579	2.73%	$9,542	$15,750	$1,600	$21,714	$15,573
19	1745592	0.91%	$540	$0	$2,000	$13,182	$17,744
19	1745594	0.91%	$270	$3,750	$1,600	$15,950	$4,691
19	1745596	0.91%	$540	$0	$2,000	$13,494	$19,226
19	1745598	2.73%	$9,542	$15,750	$1,600	$20,128	$15,767
19	1745599	1.08%	$540	$0	$4,000	$3,961	$5,709
19	2286026	0.02%	$214	$2,038,509	$8,000	$1,093,517	$1,336,980
19	2286191	0.01%	$214	$2,038,509	$8,000	$1,127,439	$1,364,027
19	2286487	0.01%	$214	$2,038,509	$8,000	$1,120,729	$1,358,608
19	2286839	0.05%	$214	$2,038,509	$8,000	$1,016,944	$1,280,001
19	28136989	0.73%	$1,746	$409,813	$0	$100,549	$168,329
20	1172723	1.71%	$193	$125,127	$385	$3,261	$0
20	1172732	1.71%	$197	$122,699	$385	$3,152	$0
20	1172735	17.24%	$197	$122,295	$385	$58,275	$0
20	1172739	1.71%	$205	$122,295	$385	$3,134	$0
20	1172741	1.71%	$205	$121,890	$385	$3,116	$0
20	1172746	1.71%	$205	$123,778	$385	$3,201	$0
20	1172756	10.16%	$209	$122,295	$385	$32,958	$0

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES ON ISSUE 2.2

Job #	Asset Identifier	Failure Probability	Direct Cost ($)	Indirect Cost ($)		PV (2015 Cost of Deviation from Optimal) ($)	2012 Cost of Deviation from Optimal ($)
				Customer Interruption Cost ($)	Other Indirect Cost ($)		
20	1172758	10.16%	$207	$121,081	$385	$32,758	$0
20	1172759	36.74%	$276	$121,890	$385	$126,951	$0
20	1172849	7.89%	$193	$123,784	$385	$25,423	$0
20	1172852	1.71%	$195	$123,784	$385	$3,166	$0
20	1172855	1.71%	$191	$17,133	$385	$3,826	$5,205
20	1172860	0.60%	$193	$122,295	$385	$327	$1,158
20	1172868	1.71%	$207	$121,890	$385	$2,882	$0
20	1172871	1.71%	$200	$121,890	$385	$3,116	$0
20	1172873	3.25%	$193	$123,784	$385	$8,743	$0
20	1172883	16.06%	$201	$122,699	$385	$100,950	$0
20	1172900	0.60%	$208	$122,430	$385	$624	$1,713
20	1172901	1.71%	$197	$122,699	$385	$3,152	$0
20	1172910	0.60%	$208	$122,225	$385	$628	$1,719
20	1172911	0.60%	$199	$125,127	$385	$318	$1,148
20	1172914	0.60%	$205	$126,486	$385	$471	$1,435
20	1172918	3.25%	$208	$129,712	$385	$9,013	$0
20	1172921	1.71%	$195	$122,699	$385	$3,117	$0
20	1172928	0.60%	$216	$124,857	$385	$590	$1,658
20	1173899	0.41%	$203	$124,188	$385	$1,814	$3,424
20	1173901	0.41%	$193	$122,295	$385	$1,532	$3,004
20	1173916	0.41%	$195	$9,446	$385	$8,968	$10,989
20	1173919	0.60%	$206	$9,446	$385	$8,524	$10,493
20	1173926	22.59%	$277	$121,081	$385	$82,910	$0
20	1173941	0.41%	$203	$122,699	$385	$1,856	$3,477
20	1174075	10.16%	$218	$123,983	$385	$36,254	$0
20	1174076	0.41%	$218	$122,090	$385	$2,477	$4,360

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES ON ISSUE 2.2

Job #	Asset Identifier	Failure Probability	Direct Cost ($)	Indirect Cost ($)		PV (2015 Cost of Deviation from Optimal) ($)	2012 Cost of Deviation from Optimal ($)
				Customer Interruption Cost ($)	Other Indirect Cost ($)		
20	1174078	0.41%	$218	$122,899	$385	$2,452	$4,329
20	1174117	0.60%	$201	$122,295	$385	$327	$1,158
20	1660186	2.68%	$745	$0	$4,500	$4,993	$0
20	1669384	0.08%	$270	$2,901,450	$8,000	$1,302,736	$1,581,639
20	1669790	0.10%	$270	$2,901,450	$8,000	$1,273,929	$1,551,067
20	1669942	0.10%	$270	$2,901,450	$8,000	$1,272,312	$1,549,352
20	1669970	0.14%	$270	$2,901,450	$8,000	$1,238,508	$1,513,477
20	1670264	0.08%	$270	$2,901,450	$8,000	$1,297,298	$1,575,868
20	1670274	0.09%	$383	$297,750	$8,000	$110,212	$134,204
20	1670524	0.01%	$383	$164,156	$8,000	$69,947	$84,138
20	1671493	0.13%	$383	$297,750	$8,000	$105,261	$128,962
20	1671545	0.09%	$383	$297,750	$8,000	$109,605	$133,560
20	1671552	0.02%	$383	$135,938	$8,000	$58,906	$70,905
20	1671653	0.01%	$270	$2,901,450	$8,000	$1,417,635	$1,702,554
20	1671746	0.12%	$383	$297,750	$8,000	$106,537	$130,313
20	1671845	0.12%	$270	$2,901,450	$8,000	$1,258,644	$1,534,846
20	1672032	0.02%	$270	$2,901,450	$8,000	$1,404,343	$1,688,477
20	1672225	0.09%	$270	$2,901,450	$8,000	$1,284,217	$1,561,986
20	1672395	0.01%	$270	$2,901,450	$8,000	$1,419,452	$1,704,309
20	1672597	0.02%	$270	$2,901,450	$8,000	$1,392,056	$1,676,289
20	1672668	0.11%	$270	$2,901,450	$8,000	$1,270,255	$1,547,168
20	1672703	0.01%	$383	$164,156	$8,000	$70,606	$84,850
20	1672838	0.02%	$383	$164,156	$8,000	$69,556	$83,758
20	1673043	0.02%	$270	$2,901,450	$8,000	$1,400,663	$1,684,826
20	1673496	0.12%	$270	$2,901,450	$8,000	$1,253,940	$1,529,854
20	1673524	0.02%	$383	$164,156	$8,000	$69,755	$83,951

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES ON ISSUE 2.2

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				Customer Interruption Cost ($)	Other Indirect Cost ($)		
20	1673772	0.10%	$270	$2,901,450	$8,000	$1,276,574	$1,553,875
20	1674378	0.01%	$270	$2,901,450	$8,000	$1,419,163	$1,704,030
20	1674432	0.02%	$270	$2,901,450	$8,000	$1,401,852	$1,686,006
20	1674534	0.10%	$270	$2,901,450	$8,000	$1,273,047	$1,550,132
20	1674551	0.02%	$383	$135,938	$8,000	$58,954	$70,951
20	1674783	0.01%	$270	$2,901,450	$8,000	$1,410,572	$1,694,655
20	1674837	0.16%	$270	$2,901,450	$8,000	$1,215,580	$1,489,144
20	1674847	0.07%	$270	$2,901,450	$8,000	$1,305,822	$1,584,915
20	1674872	0.01%	$270	$2,901,450	$8,000	$1,426,991	$1,710,381
20	1675087	0.02%	$383	$135,938	$8,000	$58,864	$70,863
20	1675447	0.03%	$270	$2,901,450	$8,000	$1,380,902	$1,665,224
20	1675659	0.02%	$383	$164,156	$8,000	$69,351	$83,559
20	1675937	0.10%	$270	$2,901,450	$8,000	$1,277,015	$1,554,343
20	1676432	0.12%	$270	$2,901,450	$8,000	$1,255,998	$1,532,038
20	1676489	0.11%	$270	$2,901,450	$8,000	$1,262,759	$1,539,213
20	1676771	0.02%	$383	$135,938	$8,000	$58,929	$70,926
20	1678649	8.03%	$2,233	$27,000	$0	$1,609	$0
20	1678859	2.44%	$2,233	$40,500	$0	$5,535	$10,717
20	1679447	0.39%	$720	$90,000	$8,000	$15,911	$22,400
20	1679911	7.32%	$2,233	$40,500	$0	$1,923	$8,194
20	1679975	6.09%	$2,233	$40,500	$0	$2,539	$8,536
20	1681856	5.73%	$2,233	$90,180	$0	$741	$1,206
20	1682159	51.72%	$2,233	$90,180	$0	$123,741	$0
20	1682544	28.15%	$2,233	$27,000	$0	$14,507	$0
20	1682987	6.26%	$2,233	$270,000	$0	$22,985	$0
20	1683181	3.06%	$2,233	$90,180	$0	$1,336	$6,303

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES ON ISSUE 2.2

Job #	Asset Identifier	Failure Probability	Direct Cost ($)	Indirect Cost ($)		PV (2015 Cost of Deviation from Optimal) ($)	2012 Cost of Deviation from Optimal ($)
				Customer Interruption Cost ($)	Other Indirect Cost ($)		
20	1683537	35.90%	$2,233	$40,500	$0	$33,089	$0
20	1684216	4.43%	$2,233	$40,500	$0	$140	$250
20	1684353	10.95%	$2,233	$40,500	$0	$6,872	$0
20	1686409	3.19%	$2,233	$40,500	$0	$4,489	$9,839
20	1686523	7.42%	$2,233	$108,000	$0	$5,611	$0
20	1687629	4.45%	$2,233	$54,000	$0	$1,526	$6,519
20	1688301	20.44%	$2,233	$90,180	$0	$43,635	$0
20	1689467	44.64%	$2,233	$40,500	$0	$42,278	$0
20	1689670	2.12%	$2,233	$54,000	$0	$9,226	$17,409
20	1690509	0.04%	$270	$2,901,450	$8,000	$1,352,760	$1,637,309
20	1690715	3.01%	$2,233	$54,000	$0	$457	$2,127
20	1691292	39.51%	$2,233	$90,180	$0	$92,456	$0
20	1691320	9.72%	$2,233	$27,000	$0	$2,692	$0
20	1691548	17.07%	$2,233	$27,000	$0	$7,404	$0
20	1692338	5.16%	$2,233	$27,000	$0	$18,838	$32,331
20	1696283	18.88%	$2,233	$270,000	$0	$128,101	$0
20	1696574	27.04%	$2,233	$54,000	$0	$33,769	$0
20	1698240	35.73%	$2,233	$90,180	$0	$82,789	$0
20	1698544	1.30%	$2,233	$27,000	$0	$12,303	$18,354
20	1700213	1.59%	$2,233	$40,500	$0	$7,364	$12,355
20	1702002	0.01%	$720	$45,000	$8,000	$17,613	$21,193
20	1703352	49.66%	$2,233	$54,000	$0	$66,813	$0
20	1704050	4.24%	$2,233	$90,180	$0	$2,613	$11,748
20	1704109	14.21%	$2,233	$0	$0	$17,827	$21,774
20	1705255	9.30%	$2,233	$90,180	$0	$0	$9,617
20	1705360	5.89%	$2,233	$90,000	$0	$6,376	$0

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES ON ISSUE 2.2

Job #	Asset Identifier	Failure Probability	Direct Cost ($)	Indirect Cost ($)		PV (2015 Cost of Deviation from Optimal) ($)	2012 Cost of Deviation from Optimal ($)
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20	1705996	0.12%	$720	$75,150	$8,000	$19,926	$25,270
20	1706310	1.14%	$720	$45,000	$8,000	$4,289	$6,898
20	1706984	0.01%	$720	$90,000	$8,000	$28,154	$33,934
20	1707617	0.27%	$720	$112,500	$8,000	$20,664	$28,041
20	1708090	4.46%	$2,233	$27,000	$0	$119	$1,057
20	1708350	10.36%	$2,233	$54,000	$0	$9,394	$0
20	1708864	2.83%	$2,233	$54,000	$0	$3,655	$8,917
20	1708931	9.26%	$2,233	$135,000	$0	$23,998	$0
20	1709051	1.51%	$2,233	$40,500	$0	$11,171	$18,134
20	1709899	0.01%	$720	$90,000	$8,000	$28,258	$34,032
20	1709982	2.95%	$2,233	$27,000	$0	$1,545	$3,366
20	1711527	3.43%	$2,233	$20,160	$0	$1,424	$3,076
20	1712818	2.15%	$2,233	$40,500	$0	$10,863	$18,820
20	1743360	11.16%	$540	$0	$2,000	$11,959	$0
20	1743361	11.16%	$540	$0	$2,000	$1,487	$0
20	1743362	11.16%	$540	$0	$2,000	$3,023	$0
20	1743363	11.16%	$540	$0	$2,000	$5,619	$0
20	1743368	11.16%	$540	$0	$2,000	$3,023	$0
20	1743369	11.16%	$540	$0	$4,000	$12,110	$0
20	1743375	4.18%	$540	$0	$2,000	$3,803	$6,493
20	1743379	6.03%	$540	$0	$4,000	$3,228	$6,526
20	1743387	11.16%	$540	$0	$2,000	$5,619	$0
20	1743394	11.16%	$540	$0	$4,000	$1,134	$0
20	1743436	11.16%	$540	$0	$4,000	$3,579	$0
20	1743443	11.16%	$540	$0	$4,000	$3,579	$0
20	1743444	11.16%	$540	$0	$2,000	$1,487	$0

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES ON ISSUE 2.2

Job #	Asset Identifier	Failure Probability	Direct Cost ($)	Indirect Cost ($)		PV (2015 Cost of Deviation from Optimal) ($)	2012 Cost of Deviation from Optimal ($)
				Customer Interruption Cost ($)	Other Indirect Cost ($)		
20	1743445	11.16%	$540	$0	$2,000	$1,487	$0
20	1743447	11.16%	$540	$0	$4,000	$3,579	$0
20	1743449	3.91%	$540	$0	$2,000	$3,950	$7,157
20	1743454	3.91%	$540	$0	$4,000	$7,247	$15,079
20	1743456	11.16%	$540	$0	$2,000	$5,619	$0
20	1743458	11.16%	$540	$0	$4,000	$38,622	$0
20	1743464	11.16%	$540	$0	$2,000	$206	$0
20	1743466	11.16%	$540	$0	$4,000	$1,594	$0
20	1743471	11.16%	$540	$0	$4,000	$1,134	$0
20	1743472	3.91%	$540	$0	$4,000	$16,932	$26,992
20	1743473	3.91%	$540	$0	$4,000	$16,932	$26,992
20	1743832	2.68%	$540	$0	$2,000	$7,478	$11,692
20	1743833	2.68%	$540	$0	$4,000	$26,557	$38,821
20	1743834	11.16%	$540	$0	$2,000	$1,487	$0
20	1743835	2.68%	$540	$0	$2,000	$7,478	$11,692
20	1743836	2.68%	$540	$0	$2,000	$7,193	$10,738
20	1743837	11.73%	$9,542	$23,625	$1,600	$15,899	$0
20	1743838	3.91%	$540	$0	$2,000	$3,950	$7,157
20	1743840	3.91%	$540	$0	$4,000	$8,962	$14,094
20	1743841	3.91%	$540	$0	$4,000	$16,932	$26,992
20	1743928	2.68%	$540	$0	$4,000	$8,048	$11,976
20	1743929	2.68%	$540	$0	$4,000	$26,557	$38,821
20	1743935	11.02%	$540	$0	$4,000	$1,255	$0
20	1743954	11.16%	$540	$0	$4,000	$1,521	$0
20	1743957	3.91%	$540	$0	$4,000	$14,111	$21,529
20	1743958	3.91%	$540	$0	$4,000	$8,962	$14,094

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES ON ISSUE 2.2

Job #	Asset Identifier	Failure Probability	Direct Cost ($)	Indirect Cost ($)		PV (2015 Cost of Deviation from Optimal) ($)	2012 Cost of Deviation from Optimal ($)
				Customer Interruption Cost ($)	Other Indirect Cost ($)		
20	1743959	3.91%	$540	$0	$2,000	$4,333	$7,178
20	1743960	58.31%	$540	$0	$2,000	$0	$0
20	1743961	3.91%	$540	$0	$4,000	$8,962	$14,094
20	1743966	11.16%	$540	$0	$4,000	$3,579	$0
20	1743970	3.91%	$540	$0	$2,000	$1,723	$4,233
20	1743972	3.91%	$540	$0	$4,000	$14,111	$21,529
20	1743973	58.32%	$540	$0	$4,000	$0	$0
20	1743974	3.91%	$540	$0	$4,000	$1,184	$572
20	2285808	0.25%	$720	$90,000	$8,000	$18,517	$24,816
20	28081649	0.09%	$720	$0	$8,000	$6,498	$7,873
20	28081654	0.10%	$720	$0	$8,000	$6,491	$7,868
20	30538092	3.34%	$2,233	$54,000	$0	$135	$1,362
20	30539083	2.56%	$2,233	$54,000	$0	$1,339	$3,623
20	30563538	0.02%	$720	$45,000	$8,000	$17,450	$21,046
20	30563551	0.01%	$720	$45,000	$8,000	$17,588	$21,171
20	30563602	0.46%	$2,233	$27,000	$0	$11,775	$15,597
20	30567082	3.18%	$2,233	$27,000	$0	$1,192	$2,876
20	30567213	0.09%	$720	$22,500	$8,000	$11,111	$13,536
20	30567220	0.08%	$720	$22,500	$8,000	$11,210	$13,638
20	30567811	0.08%	$720	$75,000	$8,000	$21,993	$26,875
20	30567812	0.12%	$720	$75,000	$8,000	$21,061	$25,897
20	30567817	0.19%	$720	$75,000	$8,000	$18,947	$23,676
20	30567825	0.08%	$720	$75,000	$8,000	$22,170	$27,061
20	30568063	0.10%	$720	$45,000	$8,000	$15,542	$19,009
20	30568290	0.01%	$720	$22,500	$8,000	$12,426	$14,920
20	30568310	0.44%	$2,233	$40,500	$0	$13,872	$18,608

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES ON ISSUE 2.2

Job #	Asset Identifier	Failure Probability	Direct Cost ($)	Indirect Cost ($)		PV (2015 Cost of Deviation from Optimal) ($)	2012 Cost of Deviation from Optimal ($)
				Customer Interruption Cost ($)	Other Indirect Cost ($)		
21	13618354	4.62%	$2,233	$72,000	$0	$1,706	$0
21	13618513	22.67%	$1,746	$29,625	$0	$6,646	$0
21	13619519	0.10%	$720	$105,000	$8,000	$27,385	$33,606
21	13623266	2.79%	$2,233	$126,000	$0	$235	$2,349
21	13625463	18.77%	$1,746	$29,625	$0	$4,611	$0
21	13629390	12.46%	$1,746	$29,625	$0	$1,313	$0
21	13630115	78.16%	$2,233	$126,000	$0	$275,699	$0
21	13631068	0.15%	$214	$2,015,475	$8,000	$983,450	$1,202,021
21	13631342	23.81%	$2,233	$126,000	$0	$75,899	$0
21	13631702	48.93%	$1,746	$49,474	$0	$57,928	$0
21	13633648	0.13%	$720	$105,000	$8,000	$26,460	$32,616
21	13634086	0.00%	$214	$2,015,475	$8,000	$1,150,178	$1,376,980
21	13636375	0.10%	$383	$46,969	$8,000	$22,287	$27,196
21	13637481	21.62%	$2,233	$126,000	$0	$63,140	$0
21	13637656	7.60%	$2,233	$126,000	$0	$15,040	$0
21	13638116	0.13%	$383	$46,969	$8,000	$21,789	$26,666
21	13639443	37.96%	$1,746	$29,625	$0	$23,310	$0
21	13642409	0.00%	$214	$2,015,475	$8,000	$1,151,081	$1,377,770
21	13644915	44.62%	$2,233	$126,000	$0	$152,407	$0
21	13650902	31.08%	$1,746	$29,625	$0	$11,040	$0
21	13653342	3.03%	$2,233	$126,000	$0	$35	$1,135
21	13653480	11.92%	$2,233	$126,000	$0	$29,878	$0
21	13653706	21.18%	$2,233	$126,000	$0	$61,642	$0
21	28160210	0.03%	$720	$105,000	$8,000	$27,108	$32,952
21	28160218	0.45%	$720	$105,000	$8,000	$13,791	$18,615
21	28713268	0.04%	$720	$105,000	$8,000	$27,042	$32,882

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES ON ISSUE 2.2

Job #	Asset Identifier	Failure Probability	Direct Cost ($)	Indirect Cost ($)		PV (2015 Cost of Deviation from Optimal) ($)	2012 Cost of Deviation from Optimal ($)
				Customer Interruption Cost ($)	Other Indirect Cost ($)		
21	28721322	1.11%	$1,746	$29,625	$0	$15,531	$20,207
21	28826552	0.10%	$720	$105,000	$8,000	$27,346	$33,564
21	28826803	3.58%	$2,233	$126,000	$0	$1,576	$0
21	28826804	153.03%	$2,233	$126,000	$0	$550,993	$0
21	28826822	4.84%	$2,233	$126,000	$0	$6,198	$0
21	28826889	0.11%	$720	$22,500	$8,000	$10,775	$13,176
21	30433772	1.23%	$1,746	$29,625	$0	$14,689	$19,309
21	30433787	23.83%	$2,233	$126,000	$0	$70,716	$0
21	30436182	4.84%	$1,746	$29,625	$0	$1,534	$3,837
21	30438398	0.03%	$720	$105,000	$8,000	$27,128	$32,973
22	1170323	0.60%	$194	$2,293	$385	$9,129	$11,007
22	1170324	0.60%	$196	$2,293	$385	$9,803	$11,814
22	1170325	0.60%	$190	$2,293	$385	$9,129	$11,008
22	1170326	0.60%	$200	$2,293	$385	$9,802	$11,814
22	1170339	0.60%	$201	$2,293	$385	$9,802	$11,813
22	1170348	0.60%	$250	$2,293	$385	$9,119	$10,997
22	1170349	0.60%	$202	$2,293	$385	$10,477	$12,621
22	1669780	0.00%	$180	$1,945,320	$8,000	$1,200,442	$1,438,051
22	1674142	1.33%	$1,549	$2,139,852	$0	$872,517	$1,267,109
22	1674200	0.00%	$180	$1,945,320	$8,000	$1,200,442	$1,438,051
22	1678788	5.50%	$1,746	$76,531	$0	$17,551	$36,253
22	1679484	2.83%	$1,746	$37,031	$0	$26,050	$38,944
22	1679795	3.46%	$1,746	$76,531	$0	$20,341	$36,606
22	1679947	0.86%	$1,746	$49,375	$0	$27,393	$37,214
22	1680231	2.49%	$1,746	$37,031	$0	$25,301	$37,395
22	1680815	3.09%	$1,746	$49,375	$0	$24,256	$38,475

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES ON ISSUE 2.2

Job #	Asset Identifier	Failure Probability	Direct Cost ($)	Indirect Cost ($)		PV (2015 Cost of Deviation from Optimal) ($)	2012 Cost of Deviation from Optimal ($)
				Customer Interruption Cost ($)	Other Indirect Cost ($)		
22	1681079	22.60%	$1,746	$56,781	$0	$50,810	$99,887
22	1681171	22.80%	$1,746	$76,531	$0	$15,934	$55,294
22	1681839	3.60%	$1,746	$76,531	$0	$20,115	$36,550
22	1682370	19.79%	$1,746	$56,781	$0	$36,102	$80,220
22	1682745	7.49%	$1,746	$49,375	$0	$28,627	$51,556
22	1683139	1.26%	$1,746	$76,531	$0	$30,139	$43,771
22	1683715	2.18%	$2,233	$139,500	$0	$7,782	$18,522
22	1683983	1.52%	$1,746	$56,781	$0	$25,839	$37,724
22	1685903	2.55%	$1,746	$34,563	$0	$25,836	$37,890
22	1686056	3.74%	$1,746	$42,858	$0	$26,254	$41,511
22	1686153	0.01%	$383	$40,688	$8,000	$20,073	$24,074
22	1687734	3.03%	$1,746	$49,375	$0	$24,223	$38,327
22	1688193	3.18%	$1,746	$56,781	$0	$22,977	$37,791
22	1688722	0.00%	$383	$40,688	$8,000	$20,125	$24,120
22	1689181	1.85%	$1,746	$49,375	$0	$24,537	$36,319
22	1691186	1.67%	$1,746	$49,375	$0	$24,804	$36,227
22	1691339	0.14%	$1,746	$24,688	$0	$21,459	$26,294
22	1692782	0.01%	$383	$40,688	$8,000	$20,110	$24,107
22	1692826	2.14%	$2,233	$103,500	$0	$9,643	$19,714
22	1693197	2.18%	$1,746	$56,781	$0	$24,165	$37,229
22	1693702	4.62%	$1,746	$42,858	$0	$27,655	$44,804
22	1694654	3.06%	$1,746	$24,688	$0	$30,051	$42,745
22	1694764	9.12%	$1,746	$49,375	$0	$30,532	$56,687
22	1694787	2.67%	$1,746	$56,781	$0	$23,574	$37,492
22	1695186	6.13%	$1,746	$56,781	$0	$23,296	$43,318
22	1696011	3.32%	$1,746	$12,344	$0	$38,579	$51,330

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES ON ISSUE 2.2

Job #	Asset Identifier	Failure Probability	Direct Cost ($)	Indirect Cost ($)		PV (2015 Cost of Deviation from Optimal) ($)	2012 Cost of Deviation from Optimal ($)
				Customer Interruption Cost ($)	Other Indirect Cost ($)		
22	1696053	1.88%	$1,746	$37,031	$0	$24,359	$35,026
22	1697309	18.23%	$1,746	$49,375	$0	$44,461	$88,638
22	1697755	4.00%	$1,746	$34,563	$0	$29,495	$45,035
22	1698008	1.07%	$1,746	$49,375	$0	$26,367	$36,599
22	1698451	2.25%	$1,746	$49,375	$0	$24,274	$36,845
22	1699935	1.46%	$1,746	$76,531	$0	$28,568	$42,437
22	1700692	7.83%	$1,746	$49,375	$0	$29,143	$52,745
22	1700803	2.86%	$1,746	$49,375	$0	$24,127	$37,903
22	1701639	2.41%	$1,746	$12,344	$0	$31,081	$41,074
22	1701652	3.82%	$1,746	$76,531	$0	$19,421	$36,116
22	1701674	0.01%	$383	$40,688	$8,000	$20,078	$24,079
22	1702304	2.69%	$1,746	$56,781	$0	$23,557	$37,517
22	1703360	1.10%	$1,746	$24,688	$0	$21,904	$29,335
22	1703512	4.13%	$1,746	$49,375	$0	$24,758	$41,036
22	1704901	1.97%	$1,746	$34,563	$0	$24,534	$35,193
22	1705060	2.10%	$1,746	$76,531	$0	$24,788	$39,426
22	1705841	2.31%	$2,233	$90,000	$0	$9,893	$19,836
22	1705895	0.94%	$1,746	$56,781	$0	$28,733	$39,605
22	1705967	5.95%	$1,746	$49,375	$0	$26,774	$46,667
22	1707086	3.61%	$1,746	$49,375	$0	$24,483	$39,739
22	1707192	0.02%	$383	$72,656	$8,000	$31,609	$38,157
22	1707802	3.50%	$1,746	$49,375	$0	$24,382	$39,413
22	1708022	2.34%	$1,746	$49,375	$0	$24,123	$36,873
22	1708979	2.96%	$1,746	$76,531	$0	$21,576	$37,248
22	1709167	9.59%	$1,746	$49,375	$0	$31,297	$58,389
22	1709379	4.25%	$1,746	$56,781	$0	$22,923	$39,637

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES ON ISSUE 2.2

Job #	Asset Identifier	Failure Probability	Direct Cost ($)	Indirect Cost ($)		PV (2015 Cost of Deviation from Optimal) ($)	2012 Cost of Deviation from Optimal ($)
				Customer Interruption Cost ($)	Other Indirect Cost ($)		
22	1709611	4.05%	$1,746	$49,375	$0	$24,674	$40,808
22	1709663	17.88%	$1,746	$76,531	$0	$14,692	$48,181
22	1710077	2.78%	$1,746	$49,375	$0	$24,080	$37,697
22	1710137	20.13%	$1,746	$49,375	$0	$57,482	$105,414
22	1710956	1.33%	$1,746	$49,375	$0	$25,528	$36,264
22	1711096	3.30%	$1,746	$42,858	$0	$25,485	$39,776
22	1711290	2.72%	$1,746	$12,344	$0	$33,633	$44,564
22	1711467	0.44%	$1,746	$42,858	$0	$28,200	$36,304
22	1711982	1.45%	$1,746	$49,375	$0	$25,199	$36,184
22	1712214	1.50%	$1,746	$37,031	$0	$24,013	$33,803
22	1712462	2.54%	$1,746	$56,781	$0	$23,664	$37,363
22	1712553	1.63%	$1,746	$49,375	$0	$24,852	$36,185
22	1742209	2.44%	$540	$0	$4,000	$1,121	$0
22	1742210	1.42%	$540	$0	$4,000	$139	$1,300
22	1742211	1.42%	$540	$0	$4,000	$139	$1,300
22	1742212	1.42%	$540	$0	$4,000	$139	$1,300
22	1742213	0.20%	$540	$0	$4,000	$5,791	$9,093
22	1742214	2.68%	$540	$0	$4,000	$541	$0
22	1742215	1.60%	$540	$0	$4,000	$340	$1,638
22	1742245	6.39%	$540	$0	$4,000	$15,108	$0
22	1742246	7.98%	$540	$0	$4,000	$19,481	$0
22	1742247	0.05%	$540	$0	$4,000	$6,524	$10,635
22	1742248	7.57%	$540	$0	$4,000	$17,518	$0
22	1742249	7.57%	$540	$0	$4,000	$18,344	$0
22	1742250	6.39%	$540	$0	$4,000	$10,006	$0
22	1742285	4.65%	$540	$0	$4,000	$5,230	$0

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES ON ISSUE 2.2

Job #	Asset Identifier	Failure Probability	Direct Cost ($)	Indirect Cost ($)		PV (2015 Cost of Deviation from Optimal) ($)	2012 Cost of Deviation from Optimal ($)
				Customer Interruption Cost ($)	Other Indirect Cost ($)		
22	1742286	4.65%	$540	$0	$4,000	$5,230	$0
22	1742287	4.65%	$540	$0	$4,000	$1,525	$0
22	1742288	4.65%	$540	$0	$4,000	$1,525	$0
22	1742289	2.00%	$540	$0	$4,000	$0	$743
22	1742290	3.91%	$270	$2,775	$1,600	$1,818	$2,728
22	1742291	4.65%	$540	$0	$4,000	$1,525	$0
22	1742294	4.65%	$540	$0	$4,000	$2,982	$0
22	1742297	3.91%	$540	$0	$2,000	$4,365	$0
22	1742299	3.91%	$540	$0	$2,000	$4,365	$0
22	1742328	4.65%	$540	$0	$4,000	$2,982	$0
22	1742331	3.91%	$540	$0	$2,000	$2,547	$0
22	1742337	3.91%	$270	$7,500	$1,600	$834	$1,664
22	1742338	4.65%	$540	$0	$4,000	$0	$389
22	1742339	4.65%	$540	$0	$4,000	$396	$0
22	1742359	6.77%	$540	$0	$4,000	$15,332	$0
22	1742360	4.65%	$540	$0	$4,000	$9,464	$0
22	1742361	4.65%	$540	$0	$4,000	$7,150	$0
22	1742362	4.65%	$540	$0	$4,000	$7,150	$0
22	1742363	4.65%	$540	$0	$4,000	$7,150	$0
22	1742364	4.65%	$540	$0	$4,000	$6,374	$0
22	1742365	4.65%	$540	$0	$4,000	$5,985	$0
22	1742366	4.65%	$540	$0	$4,000	$10,291	$0
22	1742367	4.65%	$540	$0	$4,000	$5,230	$0
22	1742374	4.65%	$540	$0	$4,000	$9,464	$0
22	1742682	4.65%	$540	$0	$4,000	$10,291	$0
22	1742683	4.65%	$540	$0	$4,000	$10,291	$0

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES ON ISSUE 2.2

Job #	Asset Identifier	Failure Probability	Direct Cost ($)	Indirect Cost ($)		PV (2015 Cost of Deviation from Optimal) ($)	2012 Cost of Deviation from Optimal ($)
				Customer Interruption Cost ($)	Other Indirect Cost ($)		
22	1742684	4.65%	$540	$0	$4,000	$7,150	$0
22	1742685	4.65%	$540	$0	$4,000	$7,150	$0
22	1742686	4.65%	$540	$0	$4,000	$5,985	$0
22	1742687	4.65%	$540	$0	$4,000	$6,374	$0
22	1742688	4.65%	$540	$0	$4,000	$5,230	$0
22	1742689	4.65%	$540	$0	$4,000	$7,150	$0
22	1742690	4.65%	$540	$0	$4,000	$5,985	$0
22	1742691	4.65%	$540	$0	$4,000	$5,985	$0
22	1742714	4.65%	$540	$0	$4,000	$5,230	$0
22	28131957	0.14%	$1,746	$76,531	$0	$53,347	$65,643
22	28131959	0.14%	$1,746	$76,531	$0	$53,401	$65,696
22	28131979	0.14%	$1,746	$37,031	$0	$28,992	$35,611
22	28131988	0.14%	$1,746	$37,031	$0	$29,041	$35,654
22	28131994	0.14%	$1,746	$37,031	$0	$29,036	$35,650
22	28132013	0.16%	$1,746	$37,031	$0	$28,719	$35,375
22	28132014	2.93%	$1,746	$37,031	$0	$26,143	$39,260
22	28132450	0.16%	$1,746	$24,688	$0	$21,280	$26,186
22	28132451	0.15%	$1,746	$24,688	$0	$21,350	$26,226
22	28132452	1.34%	$1,746	$24,688	$0	$22,714	$30,785
22	28132453	0.14%	$1,746	$37,031	$0	$29,088	$35,695
22	28132870	2.82%	$1,746	$34,563	$0	$26,443	$39,150
22	28727212	1.24%	$1,746	$49,375	$0	$25,798	$36,368
22	30411789	0.18%	$1,746	$76,531	$0	$51,261	$63,608
22	30513275	0.00%	$580	$6,770	$2,800	$948	$1,308
22	30564976	1.90%	$1,746	$76,531	$0	$25,624	$40,023
22	30565023	0.15%	$1,746	$76,531	$0	$52,869	$65,176

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES ON ISSUE 2.2

Job #	Asset Identifier	Failure Probability	Direct Cost ($)	Indirect Cost ($)		PV (2015 Cost of Deviation from Optimal) ($)	2012 Cost of Deviation from Optimal ($)
				Customer Interruption Cost ($)	Other Indirect Cost ($)		
23	13424169	16.06%	$219	$109,864	$385	$49,678	$0
23	13426644	16.06%	$188	$89,360	$385	$40,515	$0
23	13426826	0.82%	$202	$89,360	$385	$378	$1,162
23	13427162	0.82%	$202	$89,360	$385	$378	$1,162
23	13430115	0.14%	$202	$89,360	$385	$6,519	$9,007
23	13430136	0.82%	$202	$89,360	$385	$378	$1,162
23	13433354	0.82%	$197	$89,360	$385	$298	$1,028
23	13433462	0.82%	$199	$89,630	$385	$472	$1,342
23	13433881	16.06%	$202	$89,360	$385	$47,395	$0
23	13618583	8.10%	$1,746	$365,474	$0	$129,413	$250,333
23	13618999	0.03%	$416	$2,837,256	$8,000	$1,011,280	$1,220,741
23	13619207	0.03%	$416	$2,837,256	$8,000	$1,008,857	$1,218,301
23	13619776	18.80%	$1,795	$3,051,388	$0	$1,388,758	$0
23	13620017	0.02%	$416	$2,837,256	$8,000	$1,016,480	$1,225,979
23	13620099	0.01%	$383	$346,969	$8,000	$138,950	$166,870
23	13621072	0.02%	$383	$346,969	$8,000	$137,193	$165,200
23	13621761	5.16%	$1,746	$34,563	$0	$15,893	$26,817
23	13621856	0.83%	$1,746	$365,474	$0	$188,000	$250,832
23	13622617	0.04%	$416	$2,837,256	$8,000	$989,338	$1,198,639
23	13622734	0.02%	$383	$346,969	$8,000	$139,973	$168,516
23	13622827	0.02%	$416	$2,837,256	$8,000	$1,024,245	$1,233,801
23	13622861	0.07%	$1,795	$3,051,388	$0	$1,967,011	$2,382,040
23	13623203	0.02%	$416	$2,837,256	$8,000	$1,017,050	$1,226,553
23	13623491	2.89%	$1,795	$3,051,388	$0	$191,204	$449,934
23	13623508	0.02%	$383	$346,969	$8,000	$139,745	$168,299
23	13623798	0.01%	$383	$346,969	$8,000	$139,164	$166,990

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES ON ISSUE 2.2

Job #	Asset Identifier	Failure Probability	Direct Cost ($)	Indirect Cost ($)		PV (2015 Cost of Deviation from Optimal) ($)	2012 Cost of Deviation from Optimal ($)
				Customer Interruption Cost ($)	Other Indirect Cost ($)		
23	13624178	0.01%	$383	$346,969	$8,000	$138,321	$166,141
23	13624735	0.71%	$1,795	$3,051,388	$0	$972,581	$1,329,493
23	13624919	0.62%	$1,746	$365,474	$0	$201,432	$262,408
23	13625064	0.00%	$416	$2,837,256	$8,000	$1,057,926	$1,271,127
23	13625260	3.48%	$1,746	$34,563	$0	$16,011	$25,309
23	13625335	9.61%	$1,746	$39,500	$0	$14,112	$28,708
23	13625720	0.01%	$383	$239,063	$8,000	$97,128	$116,658
23	13626003	11.79%	$1,746	$251,813	$0	$42,911	$0
23	13626198	0.01%	$383	$239,063	$8,000	$97,151	$116,579
23	13627711	0.03%	$416	$2,837,256	$8,000	$1,007,718	$1,217,153
23	13628124	0.03%	$416	$2,837,256	$8,000	$1,010,282	$1,219,736
23	13628277	0.02%	$383	$239,063	$8,000	$98,554	$118,742
23	13629169	0.02%	$383	$346,969	$8,000	$140,549	$169,063
23	13629419	0.03%	$416	$2,837,256	$8,000	$1,008,359	$1,217,799
23	13629773	0.04%	$383	$346,969	$8,000	$137,243	$165,921
23	13630039	0.01%	$383	$346,969	$8,000	$139,368	$167,267
23	13630048	0.05%	$1,746	$365,474	$0	$272,470	$328,705
23	13630978	3.02%	$1,746	$365,474	$0	$15,730	$42,603
23	13631167	0.29%	$1,746	$39,500	$0	$68,456	$83,443
23	13631611	4.49%	$1,746	$34,563	$0	$15,891	$26,159
23	13631616	3.98%	$1,746	$34,563	$0	$15,851	$25,631
23	13631652	4.87%	$1,746	$49,375	$0	$12,061	$22,812
23	13631899	0.03%	$416	$2,837,256	$8,000	$1,015,625	$1,225,118
23	13632025	0.01%	$383	$239,063	$8,000	$97,112	$116,643
23	13632201	0.01%	$416	$2,837,256	$8,000	$1,039,595	$1,248,744
23	13632294	0.02%	$383	$225,000	$8,000	$93,389	$112,469

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES ON ISSUE 2.2

Job #	Asset Identifier	Failure Probability	Direct Cost ($)	Indirect Cost ($)		PV (2015 Cost of Deviation from Optimal) ($)	2012 Cost of Deviation from Optimal ($)
				Customer Interruption Cost ($)	Other Indirect Cost ($)		
23	13632478	0.01%	$383	$225,000	$8,000	$91,637	$109,970
23	13632840	0.01%	$416	$2,837,256	$8,000	$1,044,559	$1,253,676
23	13632890	8.26%	$1,795	$3,051,388	$0	$155,498	$0
23	13633029	0.01%	$383	$239,063	$8,000	$97,500	$116,996
23	13633279	1.57%	$1,795	$3,051,388	$0	$566,170	$903,560
23	13633378	9.93%	$1,746	$251,813	$0	$30,024	$0
23	13633603	2.14%	$1,795	$3,051,388	$0	$365,912	$669,606
23	13633711	0.01%	$383	$239,063	$8,000	$97,457	$116,957
23	13634952	4.41%	$1,746	$365,474	$0	$2,489	$20,869
23	13635699	0.01%	$416	$2,837,256	$8,000	$1,044,559	$1,253,676
23	13635982	3.86%	$1,746	$34,563	$0	$15,842	$25,501
23	13636097	4.30%	$1,746	$39,500	$0	$14,722	$24,925
23	13637229	12.48%	$1,746	$237,000	$0	$43,987	$0
23	13637350	1.41%	$1,795	$3,051,388	$0	$635,523	$981,990
23	13637379	0.01%	$383	$346,969	$8,000	$138,762	$166,692
23	13637508	4.75%	$1,746	$34,563	$0	$15,792	$26,317
23	13638045	0.01%	$383	$239,063	$8,000	$97,384	$116,890
23	13638313	0.91%	$1,795	$3,051,388	$0	$925,196	$1,299,053
23	13638646	32.76%	$1,746	$365,474	$0	$290,327	$0
23	13639360	5.17%	$1,795	$3,051,388	$0	$0	$117,018
23	13639627	0.01%	$416	$2,837,256	$8,000	$1,041,329	$1,250,490
23	13640291	0.02%	$416	$2,837,256	$8,000	$1,022,892	$1,232,438
23	13640715	4.92%	$1,746	$54,313	$0	$10,968	$21,778
23	13640873	0.01%	$383	$225,000	$8,000	$91,832	$110,253
23	13641164	0.02%	$383	$239,063	$8,000	$95,392	$114,814
23	13641338	0.01%	$383	$346,969	$8,000	$138,312	$166,132

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES ON ISSUE 2.2

Job #	Asset Identifier	Failure Probability	Direct Cost ($)	Indirect Cost ($)		PV (2015 Cost of Deviation from Optimal) ($)	2012 Cost of Deviation from Optimal ($)
				Customer Interruption Cost ($)	Other Indirect Cost ($)		
23	13641602	0.01%	$383	$239,063	$8,000	$97,427	$116,930
23	13641747	0.09%	$1,746	$365,474	$0	$269,528	$326,618
23	13641797	0.23%	$1,746	$34,563	$0	$26,047	$32,198
23	13641959	0.01%	$383	$239,063	$8,000	$97,468	$116,967
23	13642176	0.02%	$416	$2,837,256	$8,000	$1,023,319	$1,232,868
23	13642537	4.13%	$1,795	$3,051,388	$0	$48,292	$230,516
23	13642779	0.01%	$383	$239,063	$8,000	$96,642	$116,068
23	13643480	0.01%	$383	$346,969	$8,000	$138,662	$166,596
23	13643527	6.71%	$1,746	$34,563	$0	$16,261	$28,686
23	13643548	0.04%	$1,746	$365,474	$0	$273,778	$329,633
23	13643890	0.04%	$1,746	$365,474	$0	$273,803	$329,651
23	13643944	3.15%	$1,746	$44,438	$0	$15,152	$24,694
23	13644110	0.00%	$416	$2,837,256	$8,000	$1,045,530	$1,260,742
23	13644165	10.07%	$1,746	$251,813	$0	$31,021	$0
23	13644181	2.33%	$1,746	$49,375	$0	$16,944	$26,323
23	13644239	0.07%	$1,795	$3,051,388	$0	$1,723,094	$2,188,764
23	13644324	0.02%	$416	$2,837,256	$8,000	$1,023,746	$1,233,299
23	13644354	0.01%	$416	$2,837,256	$8,000	$1,039,548	$1,248,696
23	13645264	2.54%	$1,795	$3,051,388	$0	$40,534	$314,961
23	13645513	0.02%	$416	$2,837,256	$8,000	$1,023,604	$1,233,155
23	13645551	0.02%	$383	$346,969	$8,000	$137,204	$165,211
23	13645623	0.01%	$383	$225,000	$8,000	$91,600	$109,934
23	13645967	0.03%	$416	$2,837,256	$8,000	$1,006,150	$1,215,574
23	13646198	0.71%	$1,795	$3,051,388	$0	$969,576	$1,326,371
23	13646290	0.01%	$383	$239,063	$8,000	$97,074	$116,609
23	13646317	5.85%	$1,746	$29,625	$0	$18,223	$29,915

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES ON ISSUE 2.2

Job #	Asset Identifier	Failure Probability	Direct Cost ($)	Indirect Cost ($)		PV (2015 Cost of Deviation from Optimal) ($)	2012 Cost of Deviation from Optimal ($)
				Customer Interruption Cost ($)	Other Indirect Cost ($)		
23	13647105	0.02%	$416	$2,837,256	$8,000	$1,019,543	$1,229,065
23	13647422	0.02%	$416	$2,837,256	$8,000	$1,020,754	$1,230,285
23	13647535	0.74%	$1,795	$3,051,388	$0	$1,059,170	$1,442,186
23	13648228	0.04%	$416	$2,837,256	$8,000	$989,551	$1,198,854
23	13648466	0.01%	$383	$346,969	$8,000	$139,461	$167,356
23	13648498	0.01%	$383	$225,000	$8,000	$91,807	$110,231
23	13648922	0.31%	$1,795	$3,051,388	$0	$1,536,169	$1,940,399
23	13649608	0.01%	$383	$346,969	$8,000	$138,573	$166,512
23	13649941	0.04%	$383	$239,063	$8,000	$97,029	$117,359
23	13650724	7.91%	$1,746	$251,813	$0	$16,057	$0
23	13650805	29.06%	$1,795	$3,051,388	$0	$2,379,223	$0
23	13650964	3.97%	$1,746	$365,474	$0	$6,140	$28,170
23	13651217	0.02%	$416	$2,837,256	$8,000	$1,018,831	$1,228,347
23	13651457	4.09%	$1,746	$39,500	$0	$14,804	$24,836
23	13651536	0.03%	$416	$2,837,256	$8,000	$1,005,295	$1,214,713
23	13651875	0.02%	$383	$225,000	$8,000	$93,334	$112,419
23	13651928	0.08%	$383	$239,063	$8,000	$92,890	$113,603
23	13652718	0.11%	$383	$346,969	$8,000	$124,200	$153,529
23	13652954	0.12%	$416	$2,837,256	$8,000	$846,959	$1,054,933
23	13653012	0.02%	$383	$239,063	$8,000	$95,127	$114,547
23	13653228	1.08%	$1,795	$3,051,388	$0	$814,140	$1,178,981
23	13653252	22.87%	$1,746	$365,474	$0	$185,689	$0
23	13653273	12.13%	$1,746	$39,500	$0	$14,391	$31,065
23	13653363	9.00%	$1,795	$3,051,388	$0	$444,440	$0
23	13653498	19.13%	$1,746	$251,813	$0	$93,783	$0
23	13653660	1.61%	$1,746	$365,474	$0	$159,539	$228,900

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES ON ISSUE 2.2

Job #	Asset Identifier	Failure Probability	Direct Cost ($)	Indirect Cost ($)		PV (2015 Cost of Deviation from Optimal) ($)	2012 Cost of Deviation from Optimal ($)
				Customer Interruption Cost ($)	Other Indirect Cost ($)		
23	13653723	45.01%	$1,746	$251,813	$0	$273,495	$0
23	13653773	2.56%	$1,746	$365,474	$0	$142,676	$219,698
23	13653821	63.03%	$1,746	$237,000	$0	$371,047	$0
23	13653874	0.36%	$1,746	$365,474	$0	$223,865	$282,576
23	14067305	5.09%	$491	$0	$5,000	$414,878	$0
23	14067314	5.09%	$491	$0	$5,000	$414,878	$0
23	14067594	10.69%	$458	$0	$5,000	$49,977	$0
23	14067621	64.17%	$458	$0	$5,000	$446,121	$0
23	14067629	10.69%	$458	$0	$5,000	$45,723	$0
23	14067634	3.68%	$458	$0	$5,000	$1,533	$1,834
23	14067720	10.69%	$458	$0	$5,000	$82,867	$0
23	14067722	10.69%	$458	$0	$5,000	$82,867	$0
23	14067723	10.69%	$458	$0	$5,000	$82,867	$0
23	14067724	10.69%	$458	$0	$5,000	$82,867	$0
23	14067733	3.68%	$491	$0	$5,000	$295,204	$0
23	14067748	5.09%	$491	$0	$5,000	$867,417	$0
23	14067749	0.98%	$491	$0	$5,000	$52,778	$0
23	14080238	0.43%	$580	$445,396	$2,800	$4,468	$0
23	14080286	2.55%	$580	$445,396	$2,800	$31,911	$0
23	14080290	2.55%	$580	$780	$2,800	$16	$6
23	14080905	0.43%	$580	$445,396	$2,800	$4,468	$0
23	14081532	2.55%	$580	$445,396	$2,800	$31,911	$0
23	14081555	4.01%	$408	$0	$4,500	$67,541	$0
23	14081556	1.04%	$408	$0	$4,500	$7,928	$0
23	14081570	1.65%	$441	$0	$4,500	$142,128	$0
23	14081571	1.65%	$441	$0	$4,500	$142,128	$0

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES ON ISSUE 2.2

Job #	Asset Identifier	Failure Probability	Direct Cost ($)	Indirect Cost ($)		PV (2015 Cost of Deviation from Optimal) ($)	2012 Cost of Deviation from Optimal ($)
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23	14081573	3.18%	$408	$0	$4,500	$20,242	$0
23	14081574	3.18%	$408	$0	$4,500	$20,242	$0
23	14081616	2.55%	$580	$445,396	$2,800	$31,911	$0
23	14081617	1.83%	$408	$0	$4,500	$9,756	$0
23	14081622	1.83%	$408	$0	$4,500	$161,423	$0
23	14081623	1.83%	$441	$0	$4,500	$157,741	$0
23	14081624	1.83%	$441	$0	$4,500	$157,741	$0
23	14128285	0.07%	$540	$0	$4,000	$55,578	$75,883
23	14128287	4.65%	$540	$0	$4,000	$4,449	$0
23	14128289	4.65%	$540	$0	$4,000	$3,689	$0
23	14128290	0.35%	$540	$0	$4,000	$2,453	$4,828
23	14128291	6.39%	$540	$0	$4,000	$5,988	$0
23	14128292	6.02%	$540	$0	$4,000	$5,501	$0
23	14128293	5.66%	$540	$0	$4,000	$5,027	$0
23	14128294	6.02%	$540	$0	$4,000	$8,497	$0
23	14128295	4.65%	$540	$0	$4,000	$4,449	$0
23	14128296	0.05%	$540	$0	$4,000	$5,063	$8,060
23	14128308	6.39%	$540	$0	$4,000	$7,044	$0
23	14128309	6.39%	$540	$0	$4,000	$9,173	$0
23	14128310	6.39%	$540	$0	$4,000	$7,044	$0
23	14128311	6.39%	$540	$0	$4,000	$7,044	$0
23	14128316	2.44%	$540	$0	$4,000	$1,500	$0
23	14128317	6.02%	$540	$0	$4,000	$8,497	$0
23	14128318	6.02%	$540	$0	$4,000	$5,501	$0
23	14128319	6.02%	$540	$0	$4,000	$6,494	$0
23	14128320	6.02%	$540	$0	$4,000	$4,515	$0

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES ON ISSUE 2.2

Job #	Asset Identifier	Failure Probability	Direct Cost ($)	Indirect Cost ($)		PV (2015 Cost of Deviation from Optimal) ($)	2012 Cost of Deviation from Optimal ($)
				Customer Interruption Cost ($)	Other Indirect Cost ($)		
23	14128321	6.02%	$540	$0	$4,000	$4,515	$0
23	14128322	6.02%	$540	$0	$4,000	$4,515	$0
23	14128323	6.02%	$540	$0	$4,000	$4,515	$0
23	14128324	6.02%	$540	$0	$4,000	$6,494	$0
23	14128325	6.39%	$540	$0	$4,000	$5,988	$0
23	14128326	6.02%	$540	$0	$4,000	$5,501	$0
23	14128327	6.02%	$540	$0	$4,000	$6,494	$0
23	14128328	6.02%	$540	$0	$4,000	$6,494	$0
23	14128329	5.66%	$540	$0	$4,000	$5,959	$0
23	14128330	6.02%	$540	$0	$4,000	$6,494	$0
23	14128332	4.98%	$540	$0	$4,000	$5,758	$0
23	14128387	0.14%	$540	$0	$4,000	$5,650	$9,269
23	14128388	0.20%	$540	$0	$4,000	$5,424	$8,815
23	14128389	6.02%	$540	$0	$4,000	$5,501	$0
23	14128390	6.02%	$540	$0	$4,000	$6,494	$0
23	14128391	0.27%	$540	$0	$4,000	$3,200	$5,694
23	14128392	6.39%	$540	$0	$4,000	$9,173	$0
23	14128393	6.02%	$540	$0	$4,000	$5,501	$0
23	14128394	6.02%	$540	$0	$4,000	$5,501	$0
23	14128395	0.09%	$540	$0	$4,000	$7,102	$10,536
23	14128396	6.02%	$540	$0	$4,000	$5,501	$0
23	14128397	6.39%	$540	$0	$4,000	$5,988	$0
23	14128398	6.02%	$540	$0	$4,000	$5,501	$0
23	14128399	6.02%	$540	$0	$4,000	$5,501	$0
23	14128400	6.02%	$540	$0	$4,000	$4,515	$0
23	14128401	6.39%	$540	$0	$4,000	$4,939	$0

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES ON ISSUE 2.2

Job #	Asset Identifier	Failure Probability	Direct Cost ($)	Indirect Cost ($)		PV (2015 Cost of Deviation from Optimal) ($)	2012 Cost of Deviation from Optimal ($)
				Customer Interruption Cost ($)	Other Indirect Cost ($)		
23	14128402	1.79%	$540	$0	$4,000	$0	$921
23	14128403	6.02%	$540	$0	$4,000	$6,494	$0
23	14128404	6.02%	$540	$0	$4,000	$6,494	$0
23	14128405	6.02%	$540	$0	$4,000	$6,494	$0
23	14128406	6.39%	$540	$0	$4,000	$10,245	$0
23	14128407	6.02%	$540	$0	$4,000	$8,497	$0
23	14128408	0.20%	$540	$0	$4,000	$5,183	$8,623
23	14128409	6.39%	$540	$0	$4,000	$5,988	$0
23	14128410	6.02%	$540	$0	$4,000	$5,501	$0
23	14128411	6.02%	$540	$0	$4,000	$5,501	$0
23	14128412	6.02%	$540	$0	$4,000	$5,501	$0
23	14128413	6.39%	$540	$0	$4,000	$5,988	$0
23	14128414	5.66%	$540	$0	$4,000	$6,897	$0
23	14128415	5.31%	$540	$0	$4,000	$6,319	$0
23	14128416	4.98%	$540	$0	$4,000	$5,758	$0
23	14128417	4.98%	$540	$0	$4,000	$5,758	$0
23	14128418	4.98%	$540	$0	$4,000	$5,758	$0
23	14128419	4.98%	$540	$0	$4,000	$5,758	$0
23	14128420	4.65%	$540	$0	$4,000	$3,689	$0
23	14128421	4.65%	$540	$0	$4,000	$3,689	$0
23	14128422	4.65%	$540	$0	$4,000	$3,689	$0
23	14128423	4.65%	$540	$0	$4,000	$3,689	$0
23	14128424	4.65%	$540	$0	$4,000	$3,689	$0
23	14128425	4.65%	$540	$0	$4,000	$4,449	$0
23	14128426	4.65%	$540	$0	$4,000	$5,214	$0
23	14128427	4.65%	$540	$0	$4,000	$5,214	$0

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES ON ISSUE 2.2

Job #	Asset Identifier	Failure Probability	Direct Cost ($)	Indirect Cost ($)		PV (2015 Cost of Deviation from Optimal) ($)	2012 Cost of Deviation from Optimal ($)
				Customer Interruption Cost ($)	Other Indirect Cost ($)		
23	14128428	4.65%	$540	$0	$4,000	$3,689	$0
23	14128429	4.65%	$540	$0	$4,000	$4,449	$0
23	14128430	4.65%	$540	$0	$4,000	$5,214	$0
23	14128431	4.65%	$540	$0	$4,000	$5,214	$0
23	14128432	4.65%	$540	$0	$4,000	$4,449	$0
23	14128433	4.65%	$540	$0	$4,000	$4,449	$0
23	14128434	4.65%	$540	$0	$4,000	$4,449	$0
23	14128435	0.09%	$540	$0	$4,000	$4,772	$7,567
23	14128436	4.65%	$540	$0	$4,000	$4,449	$0
23	14128437	4.65%	$540	$0	$4,000	$5,985	$0
23	14128438	0.14%	$540	$0	$4,000	$5,863	$9,426
23	14128439	4.65%	$540	$0	$4,000	$5,985	$0
23	14128440	5.66%	$540	$0	$4,000	$5,027	$0
23	14128441	4.65%	$540	$0	$4,000	$3,689	$0
23	14128442	4.65%	$540	$0	$4,000	$3,689	$0
23	14128443	4.65%	$540	$0	$4,000	$3,689	$0
23	14128444	4.65%	$540	$0	$4,000	$3,689	$0
23	14128445	4.65%	$540	$0	$4,000	$3,689	$0
23	14128446	4.98%	$540	$0	$4,000	$4,121	$0
23	14128447	4.65%	$540	$0	$4,000	$4,449	$0
23	14128448	4.65%	$540	$0	$4,000	$4,449	$0
23	14128449	4.65%	$540	$0	$4,000	$4,449	$0
23	14128450	4.65%	$540	$0	$4,000	$4,449	$0
23	14128451	4.98%	$540	$0	$4,000	$4,937	$0
23	14128452	4.65%	$540	$0	$4,000	$4,449	$0
23	14128453	4.47%	$540	$0	$4,000	$3,745	$6,558

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES ON ISSUE 2.2

Job #	Asset Identifier	Failure Probability	Direct Cost ($)	Indirect Cost ($)		PV (2015 Cost of Deviation from Optimal) ($)	2012 Cost of Deviation from Optimal ($)
				Customer Interruption Cost ($)	Other Indirect Cost ($)		
23	14128468	6.39%	$540	$0	$4,000	$7,044	$0
23	14128469	6.39%	$540	$0	$4,000	$7,044	$0
23	14128470	4.65%	$540	$0	$4,000	$5,214	$0
23	14128471	1.86%	$540	$0	$4,000	$34,535	$48,274
23	14128488	6.39%	$540	$0	$4,000	$7,044	$0
23	14128489	3.46%	$540	$0	$4,000	$1,928	$0
23	14128490	6.39%	$540	$0	$4,000	$7,044	$0
23	14128492	4.65%	$540	$0	$4,000	$5,985	$0
23	14128493	6.39%	$540	$0	$4,000	$5,988	$0
23	14128494	0.35%	$540	$0	$4,000	$3,588	$6,741
23	14128500	1.24%	$540	$0	$4,000	$374	$1,848
23	14128507	6.02%	$540	$0	$4,000	$6,494	$0
23	14128509	4.65%	$540	$0	$4,000	$3,724	$0
23	14128510	0.20%	$540	$0	$4,000	$5,183	$8,623
23	14128512	4.65%	$540	$0	$4,000	$4,449	$0
23	14128513	4.65%	$540	$0	$4,000	$4,449	$0
23	14128514	4.65%	$540	$0	$4,000	$3,724	$0
23	14128515	4.65%	$540	$0	$4,000	$3,689	$0
23	14128516	4.65%	$540	$0	$4,000	$3,689	$0
23	14128517	4.65%	$540	$0	$4,000	$3,689	$0
23	14128518	5.37%	$540	$0	$2,000	$0	$957
23	14128519	4.65%	$540	$0	$4,000	$3,689	$0
23	14128520	0.20%	$540	$0	$4,000	$5,905	$9,175
23	14128521	4.65%	$540	$0	$4,000	$3,689	$0
23	14128522	2.91%	$540	$0	$4,000	$1,317	$6,747
23	14128523	2.91%	$540	$0	$4,000	$509	$1,684

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES ON ISSUE 2.2

Job #	Asset Identifier	Failure Probability	Direct Cost ($)	Indirect Cost ($)		PV (2015 Cost of Deviation from Optimal) ($)	2012 Cost of Deviation from Optimal ($)
				Customer Interruption Cost ($)	Other Indirect Cost ($)		
23	14128524	6.39%	$540	$0	$4,000	$6,319	$0
23	14128525	4.65%	$540	$0	$4,000	$5,985	$0
23	14128526	4.65%	$540	$0	$4,000	$4,449	$0
23	14128527	4.65%	$540	$0	$4,000	$5,230	$0
23	14131650	4.33%	$540	$0	$4,000	$5,357	$0
23	14131651	6.39%	$540	$0	$4,000	$7,044	$0
23	14131801	6.39%	$540	$0	$4,000	$9,475	$0
23	14131802	0.35%	$540	$0	$4,000	$4,138	$7,253
23	28089922	6.19%	$1,746	$44,438	$0	$12,427	$24,049
23	28090803	4.25%	$1,746	$49,375	$0	$12,867	$23,284
23	28091055	0.01%	$383	$32,813	$8,000	$16,890	$20,267
23	28091064	3.39%	$1,746	$34,563	$0	$16,022	$25,227
23	28771583	0.03%	$720	$45,000	$8,000	$17,220	$20,790
23	28771882	14.40%	$1,746	$34,563	$0	$19,698	$39,570
23	28771900	4.72%	$1,746	$34,563	$0	$15,783	$26,275
23	28772264	2.14%	$1,746	$49,375	$0	$17,627	$26,899
23	28772274	7.34%	$1,746	$49,375	$0	$10,154	$22,245
23	28772300	2.52%	$1,746	$49,375	$0	$16,333	$25,814
23	28772349	7.36%	$1,746	$49,375	$0	$10,148	$22,249
23	28772365	3.77%	$1,746	$49,375	$0	$13,623	$23,780
23	28772395	2.02%	$1,746	$49,375	$0	$18,004	$27,214
23	28772414	7.32%	$1,746	$49,375	$0	$10,161	$22,240
23	28772442	1.88%	$1,746	$39,500	$0	$17,792	$26,002
23	28772459	3.03%	$1,746	$39,500	$0	$15,739	$24,897
23	28773237	5.06%	$1,746	$39,500	$0	$14,375	$25,208
23	28773292	2.67%	$1,746	$39,500	$0	$16,225	$25,088

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES ON ISSUE 2.2

Job #	Asset Identifier	Failure Probability	Direct Cost ($)	Indirect Cost ($)		PV (2015 Cost of Deviation from Optimal) ($)	2012 Cost of Deviation from Optimal ($)
				Customer Interruption Cost ($)	Other Indirect Cost ($)		
23	28773336	2.45%	$1,746	$39,500	$0	$16,614	$25,292
23	28773341	3.20%	$1,746	$39,500	$0	$15,591	$24,887
23	28773362	2.00%	$1,746	$39,500	$0	$17,548	$25,852
23	28773373	4.85%	$1,746	$39,500	$0	$14,414	$25,076
23	28773411	4.74%	$1,746	$39,500	$0	$14,435	$25,003
23	28773417	5.52%	$1,746	$39,500	$0	$14,118	$25,332
23	28773423	6.94%	$1,746	$39,500	$0	$13,912	$26,300
23	28773431	6.06%	$1,746	$39,500	$0	$14,113	$25,773
23	28773446	3.77%	$1,746	$39,500	$0	$15,079	$24,851
23	28773465	4.62%	$1,746	$34,563	$0	$15,760	$26,160
23	28773492	8.36%	$1,746	$34,563	$0	$16,838	$30,858
23	28773505	4.67%	$1,746	$34,563	$0	$15,771	$26,213
23	28773529	8.90%	$1,746	$34,563	$0	$17,110	$31,654
23	28773533	2.83%	$1,746	$34,563	$0	$16,407	$25,071
23	28773537	9.11%	$1,746	$34,563	$0	$16,917	$31,667
23	28773544	10.34%	$1,746	$34,563	$0	$17,643	$33,582
23	28773553	1.40%	$1,746	$39,500	$0	$19,378	$27,190
23	28773565	4.04%	$1,746	$39,500	$0	$14,822	$24,817
23	28773587	6.51%	$1,746	$39,500	$0	$13,852	$25,884
23	28773597	7.35%	$1,746	$39,500	$0	$13,970	$26,700
23	28773605	4.87%	$1,746	$39,500	$0	$14,409	$25,090
23	28773616	6.19%	$1,746	$39,500	$0	$14,111	$25,877
23	28773760	2.42%	$1,746	$39,500	$0	$16,664	$25,314
23	28773764	1.28%	$1,746	$39,500	$0	$19,855	$27,570
23	28773804	7.28%	$1,746	$39,500	$0	$13,960	$26,630
23	28773810	4.14%	$1,746	$39,500	$0	$14,782	$24,860

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES ON ISSUE 2.2

Job #	Asset Identifier	Failure Probability	Direct Cost ($)	Indirect Cost ($)		PV (2015 Cost of Deviation from Optimal) ($)	2012 Cost of Deviation from Optimal ($)
				Customer Interruption Cost ($)	Other Indirect Cost ($)		
23	28773815	3.57%	$1,746	$39,500	$0	$15,211	$24,810
23	28773824	10.86%	$1,746	$39,500	$0	$14,434	$30,062
23	28773828	5.16%	$1,746	$39,500	$0	$14,356	$25,271
23	28773832	3.18%	$1,746	$49,375	$0	$14,676	$24,515
23	28773838	10.66%	$1,746	$49,375	$0	$9,061	$22,952
23	28773842	10.02%	$1,746	$49,375	$0	$9,160	$22,705
23	28773850	6.27%	$1,746	$49,375	$0	$10,906	$22,416
23	28773854	6.73%	$1,746	$49,375	$0	$10,348	$22,110
23	28773890	3.72%	$1,746	$34,563	$0	$15,984	$25,513
23	28773894	3.32%	$1,746	$34,563	$0	$16,029	$25,172
23	28773898	2.25%	$1,746	$34,563	$0	$16,966	$25,072
23	28773902	7.08%	$1,746	$34,563	$0	$16,192	$28,974
23	28773906	5.31%	$1,746	$34,563	$0	$15,928	$26,989
23	28773916	3.69%	$1,746	$34,563	$0	$15,988	$25,486
23	28773923	1.50%	$1,746	$34,563	$0	$18,308	$25,688
23	28773928	3.77%	$1,746	$34,563	$0	$15,978	$25,557
23	28773934	4.04%	$1,746	$34,563	$0	$15,856	$25,697
23	28773939	2.57%	$1,746	$34,563	$0	$16,553	$24,965
23	28773952	3.00%	$1,746	$34,563	$0	$16,241	$25,073
23	28773956	2.65%	$1,746	$34,563	$0	$16,507	$24,998
23	28774536	1.24%	$1,746	$39,500	$0	$20,022	$27,703
23	28774542	3.65%	$1,746	$39,500	$0	$15,159	$24,826
23	28774548	4.74%	$1,746	$39,500	$0	$14,434	$25,007
23	28774552	3.83%	$1,746	$39,500	$0	$14,907	$24,724
23	28774556	3.36%	$1,746	$39,500	$0	$15,340	$24,770
23	28774560	4.02%	$1,746	$39,500	$0	$14,831	$24,806

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES ON ISSUE 2.2

Job #	Asset Identifier	Failure Probability	Direct Cost ($)	Indirect Cost ($)		PV (2015 Cost of Deviation from Optimal) ($)	2012 Cost of Deviation from Optimal ($)
				Customer Interruption Cost ($)	Other Indirect Cost ($)		
23	28774565	4.97%	$1,746	$39,500	$0	$14,392	$25,149
23	28774567	2.42%	$1,746	$29,625	$0	$16,920	$24,801
23	28774572	5.32%	$1,746	$29,625	$0	$17,803	$28,900
23	28774576	4.27%	$1,746	$29,625	$0	$17,207	$27,147
23	28774580	3.82%	$1,746	$29,625	$0	$17,061	$26,491
23	28774584	2.60%	$1,746	$29,625	$0	$16,914	$24,998
23	28774588	3.03%	$1,746	$29,625	$0	$16,827	$25,382
23	28774731	4.46%	$1,746	$34,563	$0	$15,889	$26,132
23	28774738	3.69%	$1,746	$34,563	$0	$15,988	$25,482
23	28774743	6.18%	$1,746	$34,563	$0	$16,055	$27,968
23	28774752	2.36%	$1,746	$34,563	$0	$16,800	$25,011
23	28774756	6.87%	$1,746	$34,563	$0	$16,083	$28,655
23	28774760	4.92%	$1,746	$34,563	$0	$15,834	$26,523
23	28774767	4.16%	$1,746	$54,313	$0	$12,376	$22,883
23	28774772	3.43%	$1,746	$54,313	$0	$13,785	$23,999
23	28774777	1.99%	$1,746	$54,313	$0	$18,538	$28,176
23	28774781	1.24%	$1,746	$54,313	$0	$23,086	$32,427
23	28774788	8.48%	$1,746	$54,313	$0	$8,059	$20,292
23	28774796	5.07%	$1,746	$54,313	$0	$10,826	$21,698
23	28774918	4.40%	$1,746	$44,438	$0	$13,634	$24,031
23	28774922	2.42%	$1,746	$44,438	$0	$16,605	$25,646
23	28774926	4.08%	$1,746	$44,438	$0	$13,885	$24,058
23	28774931	5.55%	$1,746	$44,438	$0	$12,629	$23,808
23	28774935	4.71%	$1,746	$44,438	$0	$13,258	$23,863
23	28774943	4.57%	$1,746	$44,438	$0	$13,332	$23,840
23	28774955	4.09%	$1,746	$39,500	$0	$14,802	$24,838

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES ON ISSUE 2.2

Job #	Asset Identifier	Failure Probability	Direct Cost ($)	Indirect Cost ($)		PV (2015 Cost of Deviation from Optimal) ($)	2012 Cost of Deviation from Optimal ($)
				Customer Interruption Cost ($)	Other Indirect Cost ($)		
23	28774959	3.28%	$1,746	$39,500	$0	$15,391	$24,754
23	28774963	3.00%	$1,746	$39,500	$0	$15,769	$24,899
23	28774967	1.81%	$1,746	$39,500	$0	$18,034	$26,183
23	28774972	2.20%	$1,746	$39,500	$0	$17,089	$25,562
23	28774976	3.66%	$1,746	$39,500	$0	$15,149	$24,830
23	28774982	5.16%	$1,746	$39,500	$0	$14,356	$25,272
23	28775110	2.13%	$1,746	$44,438	$0	$17,367	$26,208
23	28775114	10.08%	$1,746	$44,438	$0	$11,484	$25,760
23	28775118	3.88%	$1,746	$44,438	$0	$14,035	$24,075
23	28775126	4.97%	$1,746	$44,438	$0	$13,121	$23,904
23	28775130	8.23%	$1,746	$44,438	$0	$11,465	$24,475
23	28775134	2.19%	$1,746	$44,438	$0	$17,224	$26,106
23	28775139	3.89%	$1,746	$44,438	$0	$14,026	$24,074
23	28775141	3.36%	$1,746	$34,563	$0	$16,026	$25,199
23	28775145	2.01%	$1,746	$34,563	$0	$17,306	$25,173
23	28775149	6.03%	$1,746	$34,563	$0	$15,996	$27,764
23	28775153	4.27%	$1,746	$34,563	$0	$15,874	$25,932
23	28775157	2.49%	$1,746	$34,563	$0	$16,697	$25,031
23	28775161	7.18%	$1,746	$34,563	$0	$16,244	$29,124
23	28775165	6.36%	$1,746	$34,563	$0	$16,124	$28,208
23	30329568	0.01%	$383	$37,500	$8,000	$18,716	$22,458
23	30330229	0.01%	$383	$32,813	$8,000	$16,895	$20,272
23	30330245	0.01%	$383	$32,813	$8,000	$16,883	$20,260
23	30330895	0.39%	$1,746	$39,500	$0	$26,475	$33,455
23	30331231	0.01%	$383	$37,500	$8,000	$18,708	$22,450
23	30332285	0.23%	$1,746	$29,625	$0	$23,251	$28,700

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES ON ISSUE 2.2

Job #	Asset Identifier	Failure Probability	Direct Cost ($)	Indirect Cost ($)		PV (2015 Cost of Deviation from Optimal) ($)	2012 Cost of Deviation from Optimal ($)
				Customer Interruption Cost ($)	Other Indirect Cost ($)		
23	30332557	0.10%	$783	$0	$4,000	$41,033	$52,075
23	30333948	0.24%	$1,746	$29,625	$0	$23,153	$28,611
23	30334762	0.01%	$383	$42,188	$8,000	$20,545	$24,652
23	30334835	0.01%	$383	$37,500	$8,000	$18,719	$22,461
23	30334974	0.01%	$383	$37,500	$8,000	$18,715	$22,457
23	30335210	5.18%	$1,746	$44,438	$0	$13,011	$23,938
23	30336803	0.69%	$383	$42,188	$8,000	$9,665	$13,818
23	30336807	0.61%	$383	$42,188	$8,000	$10,287	$14,448
23	30376799	9.67%	$1,746	$49,375	$0	$9,215	$22,568
23	30379193	0.00%	$416	$2,837,256	$8,000	$1,057,981	$1,289,805
23	30380498	0.00%	$416	$2,837,256	$8,000	$1,066,209	$1,290,352
23	30410138	2.69%	$1,746	$34,563	$0	$16,485	$25,015
23	30410153	3.93%	$1,746	$34,563	$0	$15,847	$25,573
23	30422761	0.01%	$383	$346,969	$8,000	$139,333	$167,235
23	30422827	0.28%	$1,746	$251,813	$0	$144,550	$181,178
23	30423185	0.03%	$416	$2,837,256	$8,000	$1,008,138	$1,217,304
23	30423188	0.02%	$383	$239,063	$8,000	$97,738	$117,697
23	30423190	0.02%	$383	$225,000	$8,000	$91,959	$110,824
23	30472302	0.00%	$416	$2,837,256	$8,000	$1,079,383	$1,289,263
23	30472436	0.20%	$540	$0	$4,000	$5,424	$8,815
23	30472439	0.00%	$383	$42,188	$8,000	$21,220	$25,345
23	30472500	0.00%	$383	$46,875	$8,000	$23,424	$28,048
23	30472522	0.00%	$383	$37,500	$8,000	$19,617	$23,479
23	30472563	0.00%	$383	$42,188	$8,000	$21,399	$25,593
23	30476124	0.00%	$383	$234,281	$8,000	$103,165	$125,842
23	30504700	0.00%	$416	$2,837,256	$8,000	$1,085,866	$1,312,291

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES ON ISSUE 2.2

Job #	Asset Identifier	Failure Probability	Direct Cost ($)	Indirect Cost ($)		PV (2015 Cost of Deviation from Optimal) ($)	2012 Cost of Deviation from Optimal ($)
				Customer Interruption Cost ($)	Other Indirect Cost ($)		
23	30504701	0.00%	$416	$2,837,256	$8,000	$1,084,877	$1,308,863
23	30504710	4.10%	$1,795	$3,051,388	$0	$50,021	$234,424
23	30504714	2.25%	$1,795	$3,051,388	$0	$334,871	$632,502
23	30607634	0.03%	$383	$346,969	$8,000	$138,524	$167,139
24	13619869	0.03%	$383	$229,781	$8,000	$82,387	$103,738
24	13621175	0.04%	$383	$386,719	$8,000	$147,176	$178,040
24	13621217	8.07%	$1,746	$407,344	$0	$36,424	$0
24	13621247	4.46%	$1,746	$407,344	$0	$1,866	$19,390
24	13621263	2.15%	$1,592	$3,374,499	$0	$962,846	$1,512,294
24	13622282	2.25%	$1,746	$61,719	$0	$17,702	$28,061
24	13622523	0.01%	$383	$386,719	$8,000	$154,116	$185,032
24	13623591	5.42%	$1,592	$3,374,499	$0	$128,689	$455,194
24	13624864	0.25%	$1,746	$61,719	$0	$41,292	$51,278
24	13625831	3.77%	$1,746	$59,250	$0	$12,591	$23,137
24	13625879	1.56%	$1,746	$98,948	$0	$62,500	$101,775
24	13629320	0.50%	$1,746	$242,036	$0	$82,904	$125,997
24	13629675	0.01%	$383	$386,719	$8,000	$154,446	$185,364
24	13630833	0.01%	$383	$386,719	$8,000	$154,436	$185,354
24	13630952	0.01%	$383	$386,719	$8,000	$154,357	$185,274
24	13631653	3.75%	$1,795	$0	$0	$25,462	$30,907
24	13632654	0.23%	$1,746	$64,188	$0	$43,387	$53,718
24	13632683	0.01%	$383	$386,719	$8,000	$153,994	$184,909
24	13633077	0.01%	$383	$386,719	$8,000	$153,783	$184,696
24	13633520	0.67%	$1,746	$407,344	$0	$161,069	$215,574
24	13633890	21.41%	$1,746	$407,344	$0	$198,980	$0
24	13634177	1.60%	$1,746	$98,948	$0	$63,072	$102,929

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES ON ISSUE 2.2

Job #	Asset Identifier	Failure Probability	Direct Cost ($)	Indirect Cost ($)		PV (2015 Cost of Deviation from Optimal) ($)	2012 Cost of Deviation from Optimal ($)
				Customer Interruption Cost ($)	Other Indirect Cost ($)		
24	13634696	0.01%	$383	$386,719	$8,000	$154,182	$185,098
24	13635311	11.11%	$1,746	$64,188	$0	$3,384	$14,969
24	13638329	0.43%	$1,746	$242,036	$0	$87,122	$129,356
24	13638975	0.24%	$1,746	$59,250	$0	$40,011	$49,649
24	13639191	6.78%	$1,746	$407,344	$0	$20,751	$0
24	13639368	0.01%	$383	$386,719	$8,000	$153,862	$184,776
24	13640130	4.76%	$1,746	$407,344	$0	$0	$14,561
24	13640287	0.01%	$383	$386,719	$8,000	$154,331	$185,248
24	13641436	0.26%	$1,746	$64,188	$0	$42,221	$52,556
24	13642542	4.20%	$1,746	$39,500	$0	$14,760	$24,884
24	13643920	2.99%	$1,746	$64,188	$0	$14,539	$25,188
24	13644477	0.67%	$1,746	$407,344	$0	$160,621	$215,108
24	13644896	0.01%	$383	$386,719	$8,000	$153,809	$184,723
24	13645014	0.01%	$383	$386,719	$8,000	$154,278	$185,195
24	13645650	0.01%	$383	$386,719	$8,000	$154,093	$185,009
24	13646519	0.03%	$383	$386,719	$8,000	$149,208	$180,087
24	13650105	0.45%	$1,746	$242,036	$0	$85,762	$128,317
24	13651973	43.82%	$1,746	$407,344	$0	$472,999	$0
24	13652323	0.33%	$1,746	$61,719	$0	$39,012	$49,013
24	13653420	24.11%	$1,746	$407,344	$0	$231,949	$0
24	13653421	10.30%	$1,592	$3,374,499	$0	$417,236	$0
24	13653485	3.20%	$1,746	$64,188	$0	$13,902	$24,575
24	13653574	46.66%	$1,795	$0	$0	$238,430	$290,695
24	14067527	8.63%	$458	$0	$5,000	$72,403	$0
24	14067663	8.63%	$458	$0	$5,000	$72,403	$0
24	14067721	8.63%	$458	$0	$5,000	$72,403	$0

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES ON ISSUE 2.2

Job #	Asset Identifier	Failure Probability	Direct Cost ($)	Indirect Cost ($)		PV (2015 Cost of Deviation from Optimal) ($)	2012 Cost of Deviation from Optimal ($)
				Customer Interruption Cost ($)	Other Indirect Cost ($)		
24	14067726	8.63%	$458	$0	$5,000	$72,403	$0
24	14068052	6.17%	$214	$0	$5,000	$540,657	$0
24	14080187	0.43%	$580	$38,236	$2,800	$368	$991
24	14080189	0.43%	$580	$15,631	$2,800	$1,146	$1,877
24	14080973	2.55%	$580	$0	$2,800	$1,227	$1,723
24	14081566	3.62%	$816	$0	$2,600	$11,969	$14,811
24	14082220	2.55%	$580	$719,893	$2,800	$52,451	$0
24	14128298	5.31%	$540	$0	$4,000	$9,880	$0
24	14128300	4.98%	$540	$0	$4,000	$7,416	$0
24	14128313	4.98%	$540	$0	$4,000	$7,416	$0
24	14128314	4.98%	$540	$0	$4,000	$7,416	$0
24	14128315	4.98%	$540	$0	$4,000	$7,416	$0
24	14128336	4.65%	$540	$0	$4,000	$6,761	$0
24	14128337	4.65%	$540	$0	$4,000	$5,992	$0
24	14128338	6.39%	$540	$0	$4,000	$11,859	$0
24	14128339	4.33%	$540	$0	$4,000	$18	$211
24	14128340	4.65%	$540	$0	$4,000	$7,930	$0
24	14128341	5.31%	$540	$0	$4,000	$8,983	$0
24	14128342	5.31%	$540	$0	$4,000	$9,880	$0
24	14128343	6.02%	$540	$0	$4,000	$10,518	$0
24	14128344	5.66%	$540	$0	$4,000	$9,739	$0
24	14128345	5.66%	$540	$0	$4,000	$9,739	$0
24	14128346	0.35%	$540	$0	$4,000	$3,398	$6,565
24	14128347	6.02%	$540	$0	$4,000	$11,535	$0
24	14128348	5.66%	$540	$0	$4,000	$10,695	$0
24	14128349	1.24%	$540	$0	$4,000	$0	$1,048

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES ON ISSUE 2.2

Job #	Asset Identifier	Failure Probability	Direct Cost ($)	Indirect Cost ($)		PV (2015 Cost of Deviation from Optimal) ($)	2012 Cost of Deviation from Optimal ($)
				Customer Interruption Cost ($)	Other Indirect Cost ($)		
24	14128350	5.66%	$540	$0	$4,000	$9,739	$0
24	14128351	4.65%	$540	$0	$4,000	$6,761	$0
24	14128352	4.65%	$540	$0	$4,000	$8,323	$0
24	14128353	4.65%	$540	$0	$4,000	$8,323	$0
24	14128354	4.98%	$540	$0	$4,000	$9,089	$0
24	14128355	4.65%	$540	$0	$4,000	$8,323	$0
24	14128356	4.65%	$540	$0	$4,000	$8,323	$0
24	14128357	4.65%	$540	$0	$4,000	$8,323	$0
24	14128358	6.39%	$540	$0	$4,000	$12,399	$0
24	14128359	4.65%	$540	$0	$4,000	$8,323	$0
24	14128360	4.65%	$540	$0	$4,000	$6,761	$0
24	14128361	4.65%	$540	$0	$4,000	$6,761	$0
24	14128362	4.65%	$540	$0	$4,000	$8,323	$0
24	14128363	4.98%	$540	$0	$4,000	$7,416	$0
24	14128364	5.66%	$540	$0	$4,000	$10,695	$0
24	14128365	5.66%	$540	$0	$4,000	$10,695	$0
24	14128366	5.66%	$540	$0	$4,000	$10,695	$0
24	14128367	5.66%	$540	$0	$4,000	$9,899	$0
24	14128368	5.66%	$540	$0	$4,000	$9,739	$0
24	14128369	0.27%	$540	$0	$4,000	$3,844	$7,224
24	14128370	2.21%	$540	$0	$4,000	$1,375	$0
24	14128371	4.65%	$540	$0	$4,000	$7,930	$0
24	14128372	4.65%	$540	$0	$4,000	$7,930	$0
24	14128373	4.65%	$540	$0	$4,000	$7,141	$0
24	14128375	4.65%	$540	$0	$4,000	$6,761	$0
24	14128376	4.65%	$540	$0	$4,000	$4,449	$0

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES ON ISSUE 2.2

Job #	Asset Identifier	Failure Probability	Direct Cost ($)	Indirect Cost ($)		PV (2015 Cost of Deviation from Optimal) ($)	2012 Cost of Deviation from Optimal ($)
				Customer Interruption Cost ($)	Other Indirect Cost ($)		
24	14128377	4.98%	$540	$0	$4,000	$7,416	$0
24	14128378	4.65%	$540	$0	$4,000	$5,992	$0
24	14128379	4.98%	$540	$0	$4,000	$7,416	$0
24	14128380	0.09%	$540	$0	$4,000	$6,359	$10,092
24	14128381	4.98%	$540	$0	$4,000	$7,416	$0
24	14128454	4.65%	$540	$0	$4,000	$7,930	$0
24	14128472	7.57%	$540	$0	$4,000	$13,708	$0
24	14128474	4.98%	$540	$0	$4,000	$4,937	$0
24	14128475	4.98%	$540	$0	$4,000	$4,937	$0
24	14128476	5.31%	$540	$0	$4,000	$5,440	$0
24	14128477	4.98%	$540	$0	$4,000	$4,937	$0
24	14128478	5.31%	$540	$0	$4,000	$5,440	$0
24	14128479	6.39%	$540	$0	$4,000	$7,044	$0
24	14128486	4.98%	$540	$0	$4,000	$7,416	$0
24	14128487	4.98%	$540	$0	$4,000	$7,416	$0
24	14128499	1.24%	$540	$0	$4,000	$0	$1,048
24	14128502	4.33%	$540	$0	$4,000	$6,784	$0
24	14128503	0.93%	$540	$0	$4,000	$533	$2,358
24	14128504	1.08%	$540	$0	$4,000	$359	$1,905
24	14128506	4.65%	$540	$0	$4,000	$7,141	$0
24	14131649	5.66%	$540	$0	$4,000	$8,789	$0
24	28089782	3.01%	$1,746	$59,250	$0	$14,530	$24,880
24	28089802	2.68%	$783	$0	$4,000	$8,016	$14,478
24	28089803	0.01%	$383	$58,594	$8,000	$26,897	$32,281
24	28089810	2.57%	$1,746	$61,719	$0	$16,267	$26,686
24	28091608	3.36%	$1,746	$64,188	$0	$13,271	$23,963

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES ON ISSUE 2.2

Job #	Asset Identifier	Failure Probability	Direct Cost ($)	Indirect Cost ($)		PV (2015 Cost of Deviation from Optimal) ($)	2012 Cost of Deviation from Optimal ($)
				Customer Interruption Cost ($)	Other Indirect Cost ($)		
24	28782118	2.16%	$1,746	$64,188	$0	$18,285	$28,838
24	28782135	5.50%	$1,746	$64,188	$0	$8,660	$19,599
24	28782141	9.29%	$1,746	$64,188	$0	$4,683	$16,058
24	28782160	3.54%	$1,746	$64,188	$0	$12,801	$23,514
24	28782200	5.34%	$1,746	$64,188	$0	$8,876	$19,796
24	28782676	2.75%	$1,746	$61,719	$0	$15,492	$25,945
24	28782723	0.74%	$1,746	$61,719	$0	$30,707	$40,784
24	28782753	1.85%	$1,746	$61,719	$0	$19,932	$30,216
24	28782763	3.52%	$1,746	$61,719	$0	$12,987	$23,583
24	28783364	3.98%	$1,746	$64,188	$0	$11,605	$22,368
24	28783369	4.24%	$1,746	$64,188	$0	$10,836	$21,629
24	28783374	4.73%	$1,746	$64,188	$0	$9,990	$20,841
24	28783445	3.53%	$1,746	$64,188	$0	$12,831	$23,543
24	28783461	2.90%	$1,746	$54,313	$0	$15,098	$25,100
24	28783472	6.83%	$1,746	$54,313	$0	$9,183	$20,757
24	28783485	2.69%	$1,746	$54,313	$0	$15,794	$25,714
24	28783528	2.36%	$1,746	$54,313	$0	$16,909	$26,698
24	28783540	1.88%	$1,746	$54,313	$0	$19,090	$28,686
24	28783552	3.94%	$1,746	$54,313	$0	$12,718	$23,136
24	28783666	4.21%	$1,746	$54,313	$0	$12,085	$22,611
24	28783821	0.76%	$1,746	$54,313	$0	$27,849	$36,998
24	28783834	0.24%	$1,746	$54,313	$0	$37,396	$46,335
24	28783839	4.32%	$1,746	$54,313	$0	$11,941	$22,514
24	28784139	1.76%	$1,746	$39,500	$0	$18,143	$26,255
24	28784404	5.08%	$1,746	$54,313	$0	$10,823	$21,696
24	28784448	3.80%	$1,746	$54,313	$0	$12,933	$23,296

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES ON ISSUE 2.2

Job #	Asset Identifier	Failure Probability	Direct Cost ($)	Indirect Cost ($)		PV (2015 Cost of Deviation from Optimal) ($)	2012 Cost of Deviation from Optimal ($)
				Customer Interruption Cost ($)	Other Indirect Cost ($)		
24	28784470	3.19%	$1,746	$54,313	$0	$14,419	$24,538
24	28784475	0.01%	$383	$51,563	$8,000	$24,174	$29,011
24	28784487	2.50%	$1,746	$54,313	$0	$16,457	$26,302
24	28784512	3.98%	$1,746	$54,313	$0	$12,655	$23,090
24	28784525	1.87%	$1,746	$54,313	$0	$19,142	$28,733
24	28784533	2.48%	$1,746	$54,313	$0	$16,547	$26,381
24	28784547	1.92%	$1,746	$54,313	$0	$18,815	$28,427
24	28784560	4.83%	$1,746	$54,313	$0	$11,324	$22,099
24	28784784	0.40%	$1,746	$61,719	$0	$37,278	$47,291
24	28784788	16.22%	$1,746	$61,719	$0	$1,962	$14,925
24	28784836	5.07%	$1,746	$61,719	$0	$9,505	$20,389
24	28784856	4.69%	$1,746	$61,719	$0	$10,351	$21,163
24	28784886	5.61%	$1,746	$61,719	$0	$8,885	$19,870
24	28784921	5.53%	$1,746	$9,875	$0	$32,743	$44,300
24	28785818	5.45%	$1,746	$39,500	$0	$14,118	$25,276
24	28785828	4.12%	$1,746	$39,500	$0	$14,793	$24,847
24	28785832	3.76%	$1,746	$39,500	$0	$15,088	$24,849
24	28785839	4.77%	$1,746	$39,500	$0	$14,430	$25,023
24	28785843	2.78%	$1,746	$39,500	$0	$16,100	$25,051
24	28785847	8.79%	$1,746	$39,500	$0	$13,899	$27,812
24	28785896	3.82%	$1,746	$64,188	$0	$11,933	$22,679
24	28785946	3.10%	$1,746	$64,188	$0	$14,182	$24,845
24	28785951	3.93%	$1,746	$64,188	$0	$11,698	$22,456
24	28785958	3.35%	$1,746	$64,188	$0	$13,295	$23,986
24	28785965	2.68%	$1,746	$64,188	$0	$15,747	$26,361
24	28785969	4.67%	$1,746	$64,188	$0	$10,094	$20,938

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES ON ISSUE 2.2

Job #	Asset Identifier	Failure Probability	Direct Cost ($)	Indirect Cost ($)		PV (2015 Cost of Deviation from Optimal) ($)	2012 Cost of Deviation from Optimal ($)
				Customer Interruption Cost ($)	Other Indirect Cost ($)		
24	28785981	6.93%	$1,746	$64,188	$0	$6,524	$17,628
24	28787372	3.72%	$1,746	$59,250	$0	$12,694	$23,227
24	28787379	2.84%	$1,746	$59,250	$0	$15,207	$25,513
24	28787436	7.29%	$1,746	$59,250	$0	$7,552	$19,002
24	28787465	6.91%	$1,746	$59,250	$0	$7,814	$19,168
24	28787506	4.77%	$1,746	$59,250	$0	$10,517	$21,320
24	28787517	4.36%	$1,746	$59,250	$0	$11,348	$22,045
24	28787523	5.48%	$1,746	$59,250	$0	$9,375	$20,361
24	28789033	0.95%	$1,746	$54,313	$0	$25,691	$34,915
24	28789104	3.80%	$1,746	$54,313	$0	$12,928	$23,293
24	30327528	4.79%	$1,746	$64,188	$0	$9,598	$20,454
24	30329005	0.25%	$1,746	$54,313	$0	$37,042	$45,986
24	30330700	2.06%	$1,746	$54,313	$0	$18,208	$27,877
24	30331510	5.81%	$1,746	$64,188	$0	$7,966	$18,941
24	30332917	0.01%	$383	$37,500	$8,000	$18,714	$22,456
24	30333825	5.07%	$1,746	$59,250	$0	$10,118	$21,000
24	30496681	0.00%	$383	$42,188	$8,000	$21,947	$26,336
24	30496684	0.00%	$383	$386,719	$8,000	$163,043	$197,456
24	30513648	6.17%	$214	$0	$5,000	$540,657	$0
24	30525443	4.65%	$540	$0	$4,000	$85	$83
24	30525445	7.57%	$540	$0	$4,000	$9,307	$0
24	30525758	0.00%	$383	$9,375	$8,000	$8,079	$9,651
24	30525767	0.00%	$383	$42,188	$8,000	$21,260	$25,397
24	30526466	0.00%	$383	$42,188	$8,000	$22,202	$26,679
24	30526468	0.00%	$1,746	$44,438	$0	$94,578	$113,335
24	30526478	0.00%	$383	$386,719	$8,000	$165,031	$202,008

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES ON ISSUE 2.2

Job #	Asset Identifier	Failure Probability	Direct Cost ($)	Indirect Cost ($)		PV (2015 Cost of Deviation from Optimal) ($)	2012 Cost of Deviation from Optimal ($)
				Customer Interruption Cost ($)	Other Indirect Cost ($)		
24	30526481	4.75%	$1,746	$407,344	$0	$729	$8,444
24	30526482	0.00%	$383	$386,719	$8,000	$163,120	$197,700
24	30526483	0.00%	$1,746	$9,875	$0	$72,352	$86,484
24	30526513	0.00%	$416	$0	$8,000	$19,444	$23,255
24	30526514	0.00%	$214	$3,028,397	$8,000	$1,746,471	$2,099,960
24	30526828	0.00%	$383	$42,188	$8,000	$22,427	$26,981
24	30526853	0.00%	$383	$9,375	$8,000	$9,896	$11,914
24	30573258	0.46%	$1,746	$242,036	$0	$85,366	$128,014
24	30573261	0.00%	$383	$229,781	$8,000	$105,344	$129,472
24	30573262	0.00%	$383	$229,781	$8,000	$104,715	$128,510
24	30601223	39.21%	$1,592	$3,374,499	$0	$3,501,787	$0
25	13618849	0.03%	$383	$151,781	$8,000	$63,818	$76,996
25	13619158	0.03%	$383	$272,156	$8,000	$108,936	$131,459
25	13619222	3.17%	$1,746	$159,876	$0	$113,186	$166,045
25	13620559	0.02%	$383	$328,313	$8,000	$131,121	$158,012
25	13620769	0.09%	$270	$3,641,175	$8,000	$1,597,905	$1,952,007
25	13621437	0.02%	$383	$151,781	$8,000	$64,509	$77,686
25	13621477	0.02%	$383	$328,313	$8,000	$131,012	$157,902
25	13621904	0.01%	$383	$28,125	$8,000	$15,063	$18,076
25	13622168	0.03%	$383	$201,656	$8,000	$82,377	$99,427
25	13622893	23.16%	$1,746	$286,671	$0	$149,130	$0
25	13623054	34.46%	$1,746	$345,823	$0	$299,935	$0
25	13623093	0.02%	$383	$272,156	$8,000	$109,789	$132,316
25	13623134	17.77%	$1,746	$286,671	$0	$104,180	$0
25	13623328	34.51%	$1,746	$159,876	$0	$123,226	$0
25	13623415	0.03%	$383	$272,156	$8,000	$109,317	$131,843

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES ON ISSUE 2.2

Job #	Asset Identifier	Failure Probability	Direct Cost ($)	Indirect Cost ($)		PV (2015 Cost of Deviation from Optimal) ($)	2012 Cost of Deviation from Optimal ($)
				Customer Interruption Cost ($)	Other Indirect Cost ($)		
25	13623641	0.02%	$383	$272,156	$8,000	$109,740	$132,268
25	13623858	0.03%	$383	$201,656	$8,000	$82,132	$99,181
25	13624129	0.02%	$383	$328,313	$8,000	$131,046	$157,936
25	13624734	0.02%	$383	$28,125	$8,000	$14,925	$17,949
25	13625557	41.18%	$1,746	$159,876	$0	$151,896	$0
25	13625667	21.38%	$1,746	$159,876	$0	$66,701	$0
25	13626588	0.01%	$383	$28,125	$8,000	$14,974	$17,994
25	13626727	19.05%	$1,746	$345,823	$0	$141,970	$0
25	13627455	0.02%	$383	$28,125	$8,000	$14,886	$17,913
25	13628154	0.02%	$383	$84,375	$8,000	$36,332	$43,731
25	13628359	29.40%	$1,746	$345,823	$0	$247,994	$0
25	13628942	0.01%	$383	$84,375	$8,000	$36,801	$44,193
25	13629026	0.01%	$383	$28,125	$8,000	$15,007	$18,024
25	13629283	0.01%	$383	$28,125	$8,000	$14,974	$17,993
25	13629370	0.02%	$383	$201,656	$8,000	$83,297	$100,349
25	13629958	24.54%	$1,746	$212,411	$0	$113,626	$0
25	13629973	0.01%	$383	$28,125	$8,000	$14,982	$18,001
25	13630218	0.01%	$383	$84,375	$8,000	$36,833	$44,224
25	13630441	0.02%	$383	$272,156	$8,000	$109,858	$132,386
25	13630512	0.03%	$383	$201,656	$8,000	$81,728	$98,777
25	13630980	0.33%	$383	$201,656	$8,000	$53,055	$69,778
25	13631271	0.04%	$383	$201,656	$8,000	$81,488	$98,536
25	13631507	16.12%	$1,746	$345,823	$0	$112,001	$0
25	13631668	0.02%	$383	$328,313	$8,000	$131,700	$158,594
25	13631765	0.03%	$383	$201,656	$8,000	$82,183	$99,233
25	13631993	29.10%	$1,746	$212,411	$0	$140,907	$0

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES ON ISSUE 2.2

Job #	Asset Identifier	Failure Probability	Direct Cost ($)	Indirect Cost ($)		PV (2015 Cost of Deviation from Optimal) ($)	2012 Cost of Deviation from Optimal ($)
				Customer Interruption Cost ($)	Other Indirect Cost ($)		
25	13632152	0.03%	$270	$3,641,175	$8,000	$1,724,433	$2,079,631
25	13632183	0.03%	$383	$151,781	$8,000	$64,028	$77,206
25	13632447	0.02%	$383	$272,156	$8,000	$109,775	$132,302
25	13632534	0.03%	$383	$201,656	$8,000	$82,024	$99,074
25	13632804	0.01%	$383	$28,125	$8,000	$15,014	$18,030
25	13632814	41.54%	$1,746	$212,411	$0	$215,329	$0
25	13632881	0.01%	$383	$272,156	$8,000	$109,857	$131,860
25	13632989	0.01%	$383	$28,125	$8,000	$14,959	$17,980
25	13633109	6.08%	$1,746	$159,876	$0	$1,663	$1,603
25	13633277	0.01%	$383	$84,375	$8,000	$36,811	$44,203
25	13633970	0.02%	$383	$328,313	$8,000	$131,482	$158,374
25	13634540	0.03%	$383	$328,313	$8,000	$130,434	$157,320
25	13634607	0.02%	$383	$28,125	$8,000	$14,863	$17,892
25	13634658	0.03%	$383	$151,781	$8,000	$64,150	$77,328
25	13634880	34.22%	$1,746	$286,671	$0	$241,646	$0
25	13634994	0.03%	$270	$3,641,175	$8,000	$1,719,924	$2,075,083
25	13635271	0.02%	$383	$328,313	$8,000	$131,146	$158,037
25	13636328	0.03%	$270	$3,641,175	$8,000	$1,725,831	$2,080,748
25	13636464	0.03%	$383	$272,156	$8,000	$109,255	$131,780
25	13636629	0.04%	$383	$201,656	$8,000	$81,278	$98,326
25	13638489	51.65%	$1,746	$345,823	$0	$476,267	$0
25	13638773	14.53%	$1,746	$286,671	$0	$77,166	$0
25	13639220	0.01%	$383	$32,813	$8,000	$16,816	$20,198
25	13639295	0.03%	$383	$151,781	$8,000	$64,085	$77,263
25	13639634	13.98%	$1,746	$212,411	$0	$50,500	$0
25	13640195	43.28%	$1,746	$286,671	$0	$317,362	$0

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES ON ISSUE 2.2

Job #	Asset Identifier	Failure Probability	Direct Cost ($)	Indirect Cost ($)		PV (2015 Cost of Deviation from Optimal) ($)	2012 Cost of Deviation from Optimal ($)
				Customer Interruption Cost ($)	Other Indirect Cost ($)		
25	13640228	0.02%	$383	$151,781	$8,000	$64,487	$77,663
25	13641196	0.01%	$383	$328,313	$8,000	$131,271	$157,641
25	13641466	34.86%	$1,746	$212,411	$0	$175,360	$0
25	13642675	0.01%	$383	$84,375	$8,000	$36,903	$44,293
25	13643385	0.02%	$383	$201,656	$8,000	$83,077	$100,129
25	13643621	0.03%	$383	$201,656	$8,000	$82,254	$99,304
25	13646191	13.42%	$1,746	$159,876	$0	$32,494	$0
25	13647550	19.26%	$1,746	$212,411	$0	$82,022	$0
25	13647554	0.02%	$383	$328,313	$8,000	$131,717	$158,611
25	13647589	0.01%	$383	$32,813	$8,000	$16,789	$20,172
25	13648138	0.04%	$383	$201,656	$8,000	$81,380	$98,429
25	13648170	0.02%	$383	$32,813	$8,000	$16,723	$20,111
25	13648370	0.02%	$383	$84,375	$8,000	$36,418	$43,816
25	13648401	0.01%	$383	$28,125	$8,000	$14,959	$17,980
25	13648520	0.03%	$383	$272,156	$8,000	$109,428	$131,954
25	13649289	0.03%	$383	$84,375	$8,000	$35,676	$43,085
25	13649425	0.01%	$383	$328,313	$8,000	$131,416	$157,787
25	13650117	0.02%	$383	$328,313	$8,000	$131,381	$158,273
25	13650440	0.01%	$383	$84,375	$8,000	$36,604	$43,999
25	13650526	0.03%	$270	$3,641,175	$8,000	$1,738,620	$2,093,700
25	13651150	0.03%	$383	$151,781	$8,000	$63,906	$77,084
25	13651224	7.64%	$1,746	$29,625	$0	$19,609	$33,287
25	13651232	0.01%	$383	$32,813	$8,000	$16,842	$20,222
25	13651352	3.12%	$1,746	$345,823	$0	$100,021	$166,495
25	13651685	0.01%	$383	$84,375	$8,000	$36,565	$43,960
25	13652084	0.21%	$383	$272,156	$8,000	$81,372	$103,624

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES ON ISSUE 2.2

Job #	Asset Identifier	Failure Probability	Direct Cost ($)	Indirect Cost ($)		PV (2015 Cost of Deviation from Optimal) ($)	2012 Cost of Deviation from Optimal ($)
				Customer Interruption Cost ($)	Other Indirect Cost ($)		
25	13653147	0.03%	$383	$151,781	$8,000	$63,856	$77,034
25	13653278	2.97%	$1,746	$88,875	$0	$14,393	$26,578
25	13653911	3.90%	$1,746	$34,563	$0	$15,845	$25,544
25	28155850	0.02%	$383	$28,125	$8,000	$14,907	$17,932
25	28155853	1.82%	$1,746	$29,625	$0	$17,286	$24,504
25	28155864	0.02%	$383	$28,125	$8,000	$14,908	$17,933
25	28155869	0.92%	$1,746	$29,625	$0	$18,963	$25,176
25	28155882	0.01%	$383	$28,125	$8,000	$15,035	$18,049
25	28155887	3.73%	$1,746	$29,625	$0	$17,018	$26,357
25	28155892	0.01%	$383	$28,125	$8,000	$14,947	$17,969
25	28155897	6.14%	$1,746	$29,625	$0	$18,279	$30,294
25	28155907	0.01%	$383	$28,125	$8,000	$14,959	$17,980
25	28155910	2.22%	$1,746	$29,625	$0	$17,012	$24,675
25	28155913	0.02%	$383	$28,125	$8,000	$14,861	$17,890
25	28155923	1.68%	$1,746	$29,625	$0	$17,435	$24,495
25	28155939	0.01%	$383	$28,125	$8,000	$14,949	$17,971
25	28155943	2.16%	$1,746	$29,625	$0	$17,027	$24,625
25	28155951	0.01%	$383	$28,125	$8,000	$15,029	$18,044
25	28155953	2.37%	$1,746	$29,625	$0	$16,922	$24,748
25	28155955	0.01%	$383	$28,125	$8,000	$14,953	$17,975
25	28155957	10.25%	$1,746	$29,625	$0	$21,878	$38,453
25	28155962	0.01%	$383	$28,125	$8,000	$14,989	$18,008
25	28155977	0.25%	$1,746	$29,625	$0	$23,071	$28,538
25	28155979	0.01%	$383	$28,125	$8,000	$14,986	$18,005
25	28155981	3.52%	$1,746	$29,625	$0	$16,909	$26,011
25	28156119	0.03%	$383	$272,156	$8,000	$108,929	$131,452

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES ON ISSUE 2.2

Job #	Asset Identifier	Failure Probability	Direct Cost ($)	Indirect Cost ($)		PV (2015 Cost of Deviation from Optimal) ($)	2012 Cost of Deviation from Optimal ($)
				Customer Interruption Cost ($)	Other Indirect Cost ($)		
25	28156122	0.03%	$383	$272,156	$8,000	$109,289	$131,815
25	28157267	4.64%	$1,746	$88,875	$0	$7,627	$18,821
25	28157269	0.01%	$383	$84,375	$8,000	$36,713	$44,106
25	28157271	0.98%	$1,746	$88,875	$0	$34,915	$48,286
25	28157275	0.01%	$383	$84,375	$8,000	$36,809	$44,201
25	28157277	2.22%	$1,746	$88,875	$0	$19,523	$32,158
25	28157280	0.02%	$383	$84,375	$8,000	$36,371	$43,769
25	28157284	2.47%	$1,746	$88,875	$0	$17,400	$29,883
25	28157295	1.86%	$1,746	$88,875	$0	$22,762	$35,609
25	28157300	0.01%	$383	$84,375	$8,000	$36,953	$44,343
25	28157302	1.78%	$1,746	$88,875	$0	$23,572	$36,470
25	28157311	0.01%	$383	$84,375	$8,000	$36,691	$44,085
25	28157314	1.03%	$1,746	$88,875	$0	$33,905	$47,245
25	28157321	0.01%	$383	$84,375	$8,000	$36,802	$44,194
25	28157323	1.61%	$1,746	$88,875	$0	$25,385	$38,381
25	28157327	0.02%	$383	$84,375	$8,000	$36,473	$43,870
25	28157329	3.24%	$1,746	$88,875	$0	$12,938	$24,963
25	28157333	4.86%	$1,746	$34,563	$0	$15,818	$26,446
25	28157335	0.01%	$383	$32,813	$8,000	$16,803	$20,185
25	28157337	1.11%	$1,746	$34,563	$0	$19,507	$26,507
25	28157340	0.02%	$383	$32,813	$8,000	$16,708	$20,097
25	28157343	4.14%	$1,746	$34,563	$0	$15,864	$25,796
25	28157349	0.01%	$383	$32,813	$8,000	$16,758	$20,144
25	28157355	7.65%	$1,746	$34,563	$0	$16,477	$29,806
25	28759116	0.01%	$383	$32,813	$8,000	$16,833	$20,214
25	28823553	1.68%	$1,746	$29,625	$0	$17,388	$24,450

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES ON ISSUE 2.2

Job #	Asset Identifier	Failure Probability	Direct Cost ($)	Indirect Cost ($)		PV (2015 Cost of Deviation from Optimal) ($)	2012 Cost of Deviation from Optimal ($)
				Customer Interruption Cost ($)	Other Indirect Cost ($)		
25	28824453	9.05%	$1,746	$345,823	$0	$39,717	$0
25	28824456	0.02%	$383	$328,313	$8,000	$131,264	$158,155
25	28824505	0.08%	$383	$328,313	$8,000	$118,935	$145,748
25	28824507	0.03%	$383	$328,313	$8,000	$130,752	$157,640
25	28824573	0.05%	$383	$151,781	$8,000	$59,549	$72,192
25	28824623	0.01%	$383	$151,781	$8,000	$63,053	$75,689
25	28824634	0.05%	$383	$151,781	$8,000	$59,367	$72,010
25	28824896	0.03%	$383	$151,781	$8,000	$64,081	$77,259
25	28825468	0.02%	$383	$272,156	$8,000	$109,705	$132,233
25	28825472	1.33%	$1,746	$286,671	$0	$128,946	$180,863
25	28826413	32.42%	$1,746	$286,671	$0	$226,582	$0
25	30372485	0.03%	$270	$3,641,175	$8,000	$1,727,010	$2,082,230
25	30515349	0.00%	$383	$328,313	$8,000	$136,149	$162,615
25	30611775	0.02%	$383	$328,313	$8,000	$131,314	$158,206
25	30624569	0.01%	$383	$328,313	$8,000	$131,648	$158,021
25	30624570	0.00%	$383	$328,313	$8,000	$136,202	$162,659
26	1677111	2.40%	$214	$1,672,584	$8,000	$100,613	$206,594
26	1678795	0.18%	$383	$239,344	$8,000	$77,970	$96,660
26	1680403	0.05%	$383	$98,438	$8,000	$42,344	$51,282
26	1680572	0.32%	$383	$106,313	$8,000	$30,900	$39,460
26	1680736	0.02%	$383	$63,281	$8,000	$27,910	$33,637
26	1680983	1.74%	$214	$1,672,584	$8,000	$199,692	$329,847
26	1681368	2.18%	$383	$98,438	$8,000	$3,886	$8,915
26	1683324	0.08%	$383	$98,438	$8,000	$41,146	$50,042
26	1683658	0.05%	$383	$98,438	$8,000	$42,298	$51,235
26	1683840	0.07%	$383	$98,438	$8,000	$41,850	$50,770

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES ON ISSUE 2.2

Job #	Asset Identifier	Failure Probability	Direct Cost ($)	Indirect Cost ($)		PV (2015 Cost of Deviation from Optimal) ($)	2012 Cost of Deviation from Optimal ($)
				Customer Interruption Cost ($)	Other Indirect Cost ($)		
26	1684042	0.16%	$383	$98,438	$8,000	$37,712	$46,489
26	1684787	0.31%	$383	$50,063	$8,000	$16,789	$21,339
26	1684843	0.13%	$383	$239,344	$8,000	$82,582	$101,464
26	1685164	0.61%	$214	$1,672,584	$8,000	$541,076	$710,165
26	1687442	1.61%	$383	$98,438	$8,000	$7,937	$14,109
26	1687604	0.84%	$383	$98,438	$8,000	$18,074	$25,715
26	1688620	0.17%	$383	$239,344	$8,000	$78,243	$96,944
26	1689401	0.47%	$383	$63,281	$8,000	$16,979	$22,334
26	1689744	0.61%	$383	$106,313	$8,000	$22,072	$30,088
26	1691821	2.70%	$214	$1,672,584	$8,000	$67,848	$162,415
26	1691836	1.51%	$214	$1,672,584	$8,000	$246,969	$385,431
26	1692075	0.02%	$383	$239,344	$8,000	$94,456	$113,832
26	1693113	3.22%	$383	$98,438	$8,000	$389	$3,294
26	1693432	1.00%	$214	$1,672,584	$8,000	$385,435	$541,543
26	1693828	0.26%	$383	$106,313	$8,000	$32,972	$41,626
26	1694690	0.02%	$383	$239,344	$8,000	$94,628	$114,012
26	1695787	1.76%	$383	$239,344	$8,000	$10,181	$21,247
26	1695953	0.35%	$383	$106,313	$8,000	$29,761	$38,265
26	1696169	0.02%	$383	$239,344	$8,000	$93,815	$113,164
26	1696234	0.02%	$383	$239,344	$8,000	$94,459	$113,835
26	1696966	10.47%	$1,746	$252,109	$0	$34,774	$0
26	1697565	41.55%	$1,746	$252,109	$0	$251,273	$0
26	1697765	1.04%	$383	$63,281	$8,000	$9,515	$14,300
26	1697865	1.64%	$383	$98,438	$8,000	$7,557	$13,662
26	1698303	0.02%	$214	$1,672,584	$8,000	$908,589	$1,094,726
26	1698428	14.23%	$1,746	$252,109	$0	$61,010	$0

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES ON ISSUE 2.2

Job #	Asset Identifier	Failure Probability	Direct Cost ($)	Indirect Cost ($)		PV (2015 Cost of Deviation from Optimal) ($)	2012 Cost of Deviation from Optimal ($)
				Customer Interruption Cost ($)	Other Indirect Cost ($)		
26	1698694	0.80%	$383	$63,281	$8,000	$12,136	$17,172
26	1698733	1.99%	$383	$98,438	$8,000	$4,991	$10,403
26	1699344	2.40%	$383	$98,438	$8,000	$2,672	$7,252
26	1699622	0.23%	$383	$98,438	$8,000	$34,658	$43,328
26	1699820	25.08%	$1,746	$252,109	$0	$136,537	$0
26	1700162	0.31%	$383	$98,438	$8,000	$31,750	$40,302
26	1700259	2.58%	$214	$1,672,584	$8,000	$80,571	$179,588
26	1700423	0.19%	$383	$98,438	$8,000	$36,719	$45,462
26	1700491	28.22%	$1,746	$66,656	$0	$24,949	$0
26	1701197	0.43%	$383	$106,313	$8,000	$26,922	$35,270
26	1701706	0.39%	$214	$1,672,584	$8,000	$659,148	$835,144
26	1701774	0.32%	$383	$98,438	$8,000	$31,500	$40,040
26	1701943	0.02%	$383	$50,063	$8,000	$22,935	$27,638
26	1701950	0.02%	$383	$239,344	$8,000	$91,997	$112,271
26	1701988	1.19%	$383	$50,063	$8,000	$7,249	$11,201
26	1703329	0.02%	$383	$63,281	$8,000	$27,928	$33,655
26	1703591	0.58%	$383	$98,438	$8,000	$23,631	$31,730
26	1703724	0.02%	$383	$239,344	$8,000	$94,555	$113,935
26	1703868	17.02%	$1,746	$66,656	$0	$10,807	$0
26	1703971	0.59%	$383	$106,313	$8,000	$22,637	$30,697
26	1704041	13.49%	$1,746	$252,109	$0	$55,857	$0
26	1704120	15.78%	$1,746	$252,109	$0	$71,763	$0
26	1704233	13.86%	$1,746	$66,656	$0	$6,820	$0
26	1704358	1.94%	$383	$98,438	$8,000	$5,268	$10,775
26	1704572	0.49%	$383	$106,313	$8,000	$25,208	$33,449
26	1705004	1.19%	$383	$98,438	$8,000	$12,464	$19,440

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES ON ISSUE 2.2

Job #	Asset Identifier	Failure Probability	Direct Cost ($)	Indirect Cost ($)		PV (2015 Cost of Deviation from Optimal) ($)	2012 Cost of Deviation from Optimal ($)
				Customer Interruption Cost ($)	Other Indirect Cost ($)		
26	1705008	2.70%	$383	$98,438	$8,000	$1,624	$5,593
26	1705773	0.82%	$383	$98,438	$8,000	$18,282	$25,944
26	1705921	0.37%	$383	$98,438	$8,000	$29,718	$38,175
26	1706643	0.50%	$383	$98,438	$8,000	$25,827	$34,071
26	1706883	0.98%	$383	$98,438	$8,000	$15,479	$22,845
26	1708304	0.53%	$383	$50,063	$8,000	$13,315	$17,726
26	1708450	2.02%	$214	$1,672,584	$8,000	$149,198	$268,909
26	1708464	0.52%	$383	$106,313	$8,000	$24,468	$32,660
26	1709017	0.07%	$214	$1,672,584	$8,000	$877,554	$1,062,686
26	1709557	0.09%	$214	$1,672,584	$8,000	$863,329	$1,047,809
26	1709633	0.30%	$383	$239,344	$8,000	$68,412	$87,074
26	1710559	0.10%	$383	$98,438	$8,000	$40,355	$49,224
26	1710576	0.39%	$383	$98,438	$8,000	$28,981	$37,401
26	1713324	12.67%	$1,746	$252,109	$0	$50,144	$0
26	2286561	1.29%	$214	$1,672,584	$8,000	$300,692	$446,876
26	2287032	0.09%	$214	$1,672,584	$8,000	$797,784	$1,004,759
26	7770104	0.05%	$383	$98,438	$8,000	$42,298	$51,235
26	7770105	0.07%	$383	$98,438	$8,000	$41,627	$50,540
26	28130895	67.59%	$1,746	$66,656	$0	$74,642	$0
26	28130897	0.02%	$383	$63,281	$8,000	$27,962	$33,690
26	28130903	0.02%	$383	$63,281	$8,000	$27,943	$33,670
26	28141255	0.02%	$383	$63,281	$8,000	$27,925	$33,652
26	28141257	0.02%	$383	$63,281	$8,000	$27,874	$33,600
26	28145658	50.15%	$1,746	$252,109	$0	$311,240	$0
26	28148126	0.74%	$383	$63,281	$8,000	$12,793	$17,883
26	28148128	0.83%	$383	$63,281	$8,000	$11,729	$16,731

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES ON ISSUE 2.2

Job #	Asset Identifier	Failure Probability	Direct Cost ($)	Indirect Cost ($)		PV (2015 Cost of Deviation from Optimal) ($)	2012 Cost of Deviation from Optimal ($)
				Customer Interruption Cost ($)	Other Indirect Cost ($)		
26	28159773	17.78%	$1,746	$252,109	$0	$85,676	$0
26	28734492	0.62%	$1,746	$252,109	$0	$119,856	$153,958
26	28734499	16.19%	$1,746	$252,109	$0	$74,635	$0
26	30332903	0.02%	$383	$239,344	$8,000	$93,898	$113,251
26	30332914	0.02%	$383	$239,344	$8,000	$93,961	$113,316
26	30334591	0.00%	$383	$50,063	$8,000	$24,113	$28,844
26	30334593	0.00%	$383	$50,063	$8,000	$24,110	$28,842
26	30334800	0.15%	$383	$239,344	$8,000	$80,278	$99,064
26	30342646	0.04%	$383	$106,313	$8,000	$43,373	$52,407
26	30342650	0.04%	$383	$106,313	$8,000	$43,297	$52,329
26	30411354	20.30%	$1,746	$252,109	$0	$103,250	$0
26	30411355	0.28%	$383	$106,313	$8,000	$32,441	$41,072
26	30411366	0.02%	$383	$106,313	$8,000	$44,273	$53,340
26	30489489	20.20%	$1,746	$252,109	$0	$102,585	$0
26	30489801	11.32%	$1,746	$252,109	$0	$40,728	$0
26	30489895	13.23%	$1,746	$252,109	$0	$53,998	$0
26	30489911	12.02%	$1,746	$252,109	$0	$45,564	$0
26	30489932	19.59%	$1,746	$252,109	$0	$98,322	$0
26	30491963	0.36%	$383	$106,313	$8,000	$29,276	$37,756
26	30492335	0.48%	$383	$106,313	$8,000	$25,566	$33,830
26	30492336	0.36%	$383	$106,313	$8,000	$29,441	$37,929
26	30492677	0.21%	$383	$106,313	$8,000	$35,422	$44,173
26	30494756	0.68%	$383	$239,344	$8,000	$41,198	$57,494
26	30494818	0.01%	$383	$239,344	$8,000	$95,993	$115,842
26	30495210	0.14%	$383	$50,063	$8,000	$20,158	$24,796
26	30495211	0.32%	$383	$50,063	$8,000	$16,544	$21,086

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES ON ISSUE 2.2

Job #	Asset Identifier	Failure Probability	Direct Cost ($)	Indirect Cost ($)		PV (2015 Cost of Deviation from Optimal) ($)	2012 Cost of Deviation from Optimal ($)
				Customer Interruption Cost ($)	Other Indirect Cost ($)		
26	30495236	0.59%	$383	$50,063	$8,000	$12,574	$16,948
26	30498680	0.06%	$720	$22,500	$8,000	$11,548	$13,996
26	30498937	0.05%	$720	$22,500	$8,000	$11,612	$14,060
26	30498948	0.47%	$720	$22,500	$8,000	$7,906	$10,358
26	30498951	0.05%	$720	$22,500	$8,000	$11,557	$14,005
26	30512711	0.00%	$383	$239,344	$8,000	$100,410	$119,916
26	30512712	0.02%	$383	$239,344	$8,000	$94,651	$114,036
26	30514687	0.02%	$383	$239,344	$8,000	$94,578	$113,960
26	30514697	0.00%	$1,746	$252,109	$0	$190,463	$229,178
27	1220928	3.68%	$491	$0	$5,000	$140,299	$0
27	1220929	2.19%	$214	$0	$5,000	$160,178	$0
27	1663211	0.92%	$614	$0	$4,000	$31,979	$0
27	1663212	0.92%	$614	$0	$4,000	$31,979	$0
27	1663213	0.92%	$614	$0	$4,000	$31,979	$0
27	1677232	0.01%	$214	$1,775,025	$8,000	$973,300	$1,181,958
27	1677626	0.00%	$416	$2,191,517	$8,000	$816,091	$981,806
27	1678185	0.01%	$383	$42,188	$8,000	$21,127	$25,679
27	1679989	0.03%	$214	$1,775,025	$8,000	$931,127	$1,149,989
27	1684935	0.04%	$416	$2,191,517	$8,000	$714,504	$903,163
27	1684967	0.02%	$383	$42,188	$8,000	$21,508	$26,454
27	1685501	0.40%	$1,795	$2,356,914	$0	$584,113	$896,237
27	1685874	0.03%	$416	$1,497,879	$8,000	$505,138	$636,000
27	1686570	0.00%	$214	$1,775,025	$8,000	$1,016,453	$1,216,031
27	1692121	0.01%	$720	$600,000	$8,000	$145,234	$177,530
27	1693422	0.19%	$1,746	$44,438	$0	$51,767	$66,586
27	1694423	0.36%	$1,746	$44,438	$0	$70,885	$92,764

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES ON ISSUE 2.2

Job #	Asset Identifier	Failure Probability	Direct Cost ($)	Indirect Cost ($)		PV (2015 Cost of Deviation from Optimal) ($)	2012 Cost of Deviation from Optimal ($)
				Customer Interruption Cost ($)	Other Indirect Cost ($)		
27	1695146	0.00%	$720	$600,000	$8,000	$149,466	$181,130
27	1696959	0.00%	$214	$1,775,025	$8,000	$1,013,109	$1,213,110
27	1705016	0.00%	$214	$1,775,025	$8,000	$1,013,189	$1,213,179
27	1705619	0.03%	$214	$1,775,025	$8,000	$923,100	$1,144,240
27	1707748	0.01%	$720	$600,000	$8,000	$144,045	$176,521
27	1712228	0.01%	$214	$1,775,025	$8,000	$981,531	$1,188,449
27	2285677	0.07%	$214	$1,775,025	$8,000	$865,838	$1,108,221
27	2285681	0.01%	$416	$2,191,517	$8,000	$779,789	$952,336
27	2285763	0.02%	$214	$1,775,025	$8,000	$933,852	$1,151,985
27	2285784	0.02%	$214	$1,775,025	$8,000	$937,269	$1,154,490
27	2285789	0.02%	$214	$1,775,025	$8,000	$947,136	$1,161,823
27	2285853	0.03%	$416	$1,497,879	$8,000	$509,910	$638,620
27	2285862	0.59%	$1,795	$1,610,927	$0	$318,789	$532,627
27	2285890	0.01%	$416	$2,191,517	$8,000	$787,300	$958,344
27	2285966	0.01%	$214	$1,775,025	$8,000	$964,024	$1,174,724
27	2286152	0.03%	$214	$1,775,025	$8,000	$931,980	$1,150,593
27	2286184	0.04%	$416	$1,497,879	$8,000	$496,247	$631,792
27	2286215	0.03%	$416	$1,497,879	$8,000	$512,730	$640,346
27	2286275	0.58%	$1,795	$2,356,914	$0	$450,704	$756,645
27	2286314	0.75%	$2,233	$720,000	$0	$49,045	$108,731
27	2286324	0.06%	$416	$1,497,879	$8,000	$488,485	$629,633
27	2286486	0.02%	$416	$1,497,879	$8,000	$513,611	$640,841
27	2286637	0.02%	$214	$1,775,025	$8,000	$953,433	$1,166,609
27	2286693	0.02%	$416	$1,497,879	$8,000	$515,529	$642,024
27	2286705	0.02%	$416	$1,497,879	$8,000	$522,169	$646,318
27	2286779	0.02%	$416	$2,191,517	$8,000	$735,387	$918,140

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES ON ISSUE 2.2

Job #	Asset Identifier	Failure Probability	Direct Cost ($)	Indirect Cost ($)		PV (2015 Cost of Deviation from Optimal) ($)	2012 Cost of Deviation from Optimal ($)
				Customer Interruption Cost ($)	Other Indirect Cost ($)		
27	2286849	0.01%	$416	$1,497,879	$8,000	$531,245	$652,519
27	2286933	0.02%	$416	$2,191,517	$8,000	$749,121	$928,435
28	13618512	0.04%	$1,795	$6,072,638	$0	$3,915,589	$4,748,535
28	13619392	0.01%	$383	$159,375	$8,000	$66,398	$79,710
28	13619439	0.49%	$416	$5,646,488	$8,000	$837,037	$1,239,078
28	13619442	0.01%	$383	$131,250	$8,000	$55,058	$66,096
28	13619556	0.00%	$383	$1,576,594	$8,000	$631,288	$755,171
28	13619589	3.86%	$1,746	$88,875	$0	$20,746	$39,622
28	13619599	0.02%	$383	$375,188	$8,000	$149,819	$180,593
28	13619974	23.97%	$1,746	$612,349	$0	$338,301	$0
28	13620452	1.00%	$416	$5,646,488	$8,000	$431,635	$799,823
28	13620606	1.80%	$1,746	$44,438	$0	$24,427	$35,620
28	13621133	0.07%	$1,746	$1,660,679	$0	$1,084,899	$1,328,296
28	13621774	13.26%	$1,746	$612,349	$0	$145,167	$0
28	13621815	11.30%	$1,746	$138,250	$0	$0	$15,447
28	13621958	0.01%	$383	$1,576,594	$8,000	$621,443	$746,336
28	13622324	0.01%	$383	$131,250	$8,000	$54,977	$66,016
28	13623112	0.03%	$383	$89,063	$8,000	$40,387	$48,695
28	13623293	1.54%	$1,746	$59,250	$0	$27,516	$40,365
28	13623442	16.53%	$1,746	$612,349	$0	$206,382	$0
28	13623546	0.03%	$416	$5,646,488	$8,000	$2,001,062	$2,416,231
28	13623978	0.69%	$1,746	$69,125	$0	$34,862	$46,867
28	13624233	0.33%	$1,746	$612,349	$0	$306,235	$393,090
28	13624526	0.00%	$383	$1,576,594	$8,000	$630,670	$754,496
28	13624546	0.01%	$383	$581,344	$8,000	$228,426	$274,474
28	13625141	0.01%	$383	$581,344	$8,000	$230,057	$276,204

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES ON ISSUE 2.2

Job #	Asset Identifier	Failure Probability	Direct Cost ($)	Indirect Cost ($)		PV (2015 Cost of Deviation from Optimal) ($)	2012 Cost of Deviation from Optimal ($)
				Customer Interruption Cost ($)	Other Indirect Cost ($)		
28	13625185	0.00%	$383	$1,576,594	$8,000	$630,525	$754,493
28	13625301	0.01%	$383	$159,375	$8,000	$65,807	$79,034
28	13625464	7.92%	$1,746	$612,349	$0	$49,313	$0
28	13625577	0.09%	$383	$84,469	$8,000	$34,600	$43,020
28	13625921	0.02%	$383	$375,188	$8,000	$150,228	$180,985
28	13626011	0.00%	$383	$1,576,594	$8,000	$627,597	$751,340
28	13626300	1.51%	$1,746	$1,660,679	$0	$211,015	$391,814
28	13626737	0.03%	$416	$5,646,488	$8,000	$2,003,507	$2,418,702
28	13627064	0.00%	$383	$1,576,594	$8,000	$630,944	$754,750
28	13627088	0.00%	$383	$65,625	$8,000	$30,103	$36,053
28	13627354	0.00%	$383	$1,576,594	$8,000	$630,902	$754,828
28	13627607	1.69%	$1,746	$1,660,679	$0	$182,818	$363,880
28	13627665	1.02%	$1,746	$88,875	$0	$42,959	$62,008
28	13628085	0.10%	$416	$5,646,488	$8,000	$1,610,851	$2,032,188
28	13628106	0.00%	$383	$1,576,594	$8,000	$625,847	$749,652
28	13628321	0.03%	$383	$75,000	$8,000	$30,968	$38,068
28	13628342	0.00%	$383	$1,576,594	$8,000	$626,957	$750,722
28	13628666	0.02%	$383	$375,188	$8,000	$150,001	$180,768
28	13628810	1.67%	$1,746	$1,660,679	$0	$185,620	$367,423
28	13628885	0.00%	$383	$1,576,594	$8,000	$626,770	$750,543
28	13629496	1.81%	$1,746	$1,660,679	$0	$159,802	$336,038
28	13629531	0.09%	$383	$375,188	$8,000	$131,861	$167,203
28	13629575	0.01%	$720	$22,500	$8,000	$13,565	$16,276
28	13629664	0.40%	$1,746	$395,198	$0	$310,132	$405,348
28	13629712	3.53%	$1,746	$59,250	$0	$22,648	$38,196
28	13629796	4.40%	$1,746	$1,660,679	$0	$4,802	$48,459

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES ON ISSUE 2.2

Job #	Asset Identifier	Failure Probability	Direct Cost ($)	Indirect Cost ($)		PV (2015 Cost of Deviation from Optimal) ($)	2012 Cost of Deviation from Optimal ($)
				Customer Interruption Cost ($)	Other Indirect Cost ($)		
28	13629845	4.39%	$1,746	$167,875	$0	$14,362	$38,082
28	13629868	0.00%	$383	$1,576,594	$8,000	$629,383	$753,301
28	13629954	0.00%	$383	$1,576,594	$8,000	$631,105	$754,899
28	13630245	0.79%	$1,746	$88,875	$0	$44,457	$62,368
28	13630451	0.00%	$383	$1,576,594	$8,000	$625,661	$749,472
28	13630651	0.01%	$383	$1,576,594	$8,000	$621,353	$747,192
28	13630731	3.41%	$1,746	$612,349	$0	$15,245	$53,217
28	13631937	18.72%	$1,746	$1,660,679	$0	$730,476	$0
28	13632216	0.03%	$416	$5,646,488	$8,000	$2,001,781	$2,416,958
28	13633076	0.55%	$1,746	$1,660,679	$0	$745,045	$1,021,720
28	13633416	1.67%	$1,746	$1,660,679	$0	$185,478	$367,243
28	13633723	0.00%	$1,746	$1,660,679	$0	$795,481	$1,159,754
28	13634588	0.07%	$383	$75,000	$8,000	$28,543	$35,510
28	13634615	19.52%	$1,746	$1,660,679	$0	$773,114	$0
28	13635307	0.00%	$383	$93,750	$8,000	$41,474	$49,614
28	13635321	4.00%	$1,746	$1,660,679	$0	$0	$72,814
28	13635325	0.00%	$383	$1,576,594	$8,000	$626,371	$750,977
28	13635336	0.00%	$383	$1,576,594	$8,000	$627,024	$750,787
28	13635348	0.01%	$383	$1,576,594	$8,000	$621,461	$747,287
28	13635570	0.03%	$383	$93,750	$8,000	$37,580	$46,272
28	13635607	0.00%	$383	$1,576,594	$8,000	$626,852	$750,622
28	13635851	0.00%	$383	$1,576,594	$8,000	$627,817	$751,639
28	13635922	0.03%	$383	$375,188	$8,000	$148,393	$179,230
28	13636369	0.00%	$383	$1,576,594	$8,000	$626,651	$750,428
28	13636702	0.00%	$1,746	$1,660,679	$0	$1,149,520	$1,398,360
28	13636862	0.78%	$1,746	$395,198	$0	$363,628	$490,423

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES ON ISSUE 2.2

Job #	Asset Identifier	Failure Probability	Direct Cost ($)	Indirect Cost ($)		PV (2015 Cost of Deviation from Optimal) ($)	2012 Cost of Deviation from Optimal ($)
				Customer Interruption Cost ($)	Other Indirect Cost ($)		
28	13637238	0.16%	$416	$5,646,488	$8,000	$1,425,366	$1,846,218
28	13637437	0.01%	$720	$187,500	$8,000	$49,428	$59,367
28	13637582	0.06%	$383	$37,500	$8,000	$17,595	$21,471
28	13637710	0.01%	$383	$1,576,594	$8,000	$619,412	$744,424
28	13637868	15.56%	$1,746	$612,349	$0	$186,506	$0
28	13638235	0.23%	$383	$75,000	$8,000	$22,097	$29,553
28	13638366	10.95%	$1,746	$88,974	$0	$15,208	$48,364
28	13638405	0.03%	$383	$65,625	$8,000	$27,620	$33,700
28	13638554	0.09%	$1,746	$1,660,679	$0	$1,057,247	$1,300,162
28	13638760	0.09%	$1,746	$1,660,679	$0	$1,058,716	$1,301,659
28	13638809	0.01%	$383	$159,375	$8,000	$66,251	$79,593
28	13639041	0.00%	$383	$1,576,594	$8,000	$626,614	$750,392
28	13639092	2.13%	$1,746	$1,660,679	$0	$106,257	$261,138
28	13639812	0.24%	$1,746	$64,188	$0	$42,863	$53,196
28	13639931	0.02%	$383	$375,188	$8,000	$150,532	$181,275
28	13640373	14.90%	$1,746	$612,349	$0	$176,846	$0
28	13640403	0.01%	$383	$1,576,594	$8,000	$619,127	$744,156
28	13640731	10.23%	$1,746	$1,660,679	$0	$282,901	$0
28	13640782	0.02%	$383	$375,188	$8,000	$150,547	$181,290
28	13641770	0.00%	$383	$93,750	$8,000	$41,156	$49,324
28	13641794	0.01%	$383	$1,576,594	$8,000	$623,717	$748,478
28	13642015	0.02%	$383	$581,344	$8,000	$228,461	$275,232
28	13642162	0.00%	$383	$1,576,594	$8,000	$630,893	$754,820
28	13642177	0.01%	$383	$1,576,594	$8,000	$613,387	$738,751
28	13642678	1.61%	$1,746	$98,750	$0	$42,000	$65,010
28	13642715	1.73%	$1,746	$1,660,679	$0	$176,307	$355,651

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES ON ISSUE 2.2

Job #	Asset Identifier	Failure Probability	Direct Cost ($)	Indirect Cost ($)		PV (2015 Cost of Deviation from Optimal) ($)	2012 Cost of Deviation from Optimal ($)
				Customer Interruption Cost ($)	Other Indirect Cost ($)		
28	13642935	0.01%	$383	$581,344	$8,000	$229,859	$275,920
28	13643095	0.01%	$383	$159,375	$8,000	$65,807	$79,034
28	13643277	0.03%	$383	$581,344	$8,000	$227,402	$274,195
28	13643350	0.49%	$720	$22,500	$8,000	$43,870	$55,785
28	13643452	1.45%	$1,746	$88,875	$0	$41,963	$63,173
28	13643543	0.09%	$383	$84,469	$8,000	$33,277	$41,429
28	13644054	2.86%	$1,746	$79,000	$0	$23,912	$40,867
28	13644087	13.97%	$1,746	$1,660,679	$0	$479,886	$0
28	13644197	0.03%	$383	$375,188	$8,000	$148,658	$179,483
28	13644304	0.31%	$1,746	$395,198	$0	$299,119	$386,074
28	13645637	0.26%	$1,746	$1,660,679	$0	$801,896	$1,037,278
28	13646003	5.61%	$1,746	$79,000	$0	$57,902	$100,012
28	13646305	0.00%	$383	$1,576,594	$8,000	$626,718	$750,492
28	13646319	0.27%	$1,746	$64,188	$0	$42,005	$52,341
28	13646335	0.01%	$383	$1,576,594	$8,000	$619,737	$744,730
28	13646642	0.02%	$416	$5,646,488	$8,000	$2,030,555	$2,446,030
28	13646780	3.40%	$1,746	$1,660,679	$0	$13,187	$112,313
28	13647308	0.00%	$383	$1,576,594	$8,000	$630,913	$754,722
28	13647346	0.00%	$1,746	$1,660,679	$0	$1,013,721	$1,267,327
28	13647449	0.00%	$383	$1,576,594	$8,000	$623,374	$747,266
28	13647455	0.01%	$383	$65,625	$8,000	$29,848	$35,793
28	13647723	0.36%	$1,746	$612,349	$0	$295,374	$381,768
28	13648068	25.71%	$1,746	$612,349	$0	$373,087	$0
28	13648681	0.01%	$383	$581,344	$8,000	$229,103	$275,157
28	13649358	0.00%	$383	$1,576,594	$8,000	$626,823	$750,593
28	13649811	0.00%	$383	$1,576,594	$8,000	$630,570	$754,533

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES ON ISSUE 2.2

Job #	Asset Identifier	Failure Probability	Direct Cost ($)	Indirect Cost ($)		PV (2015 Cost of Deviation from Optimal) ($)	2012 Cost of Deviation from Optimal ($)
				Customer Interruption Cost ($)	Other Indirect Cost ($)		
28	13649822	0.00%	$383	$1,576,594	$8,000	$627,806	$751,542
28	13649824	0.02%	$383	$84,469	$8,000	$38,651	$46,725
28	13649970	13.27%	$1,746	$612,349	$0	$145,357	$0
28	13650199	0.00%	$383	$1,576,594	$8,000	$626,957	$750,722
28	13650368	0.00%	$383	$1,576,594	$8,000	$626,718	$750,492
28	13651220	2.42%	$1,746	$39,500	$0	$22,742	$33,968
28	13651293	0.00%	$383	$1,576,594	$8,000	$630,265	$754,262
28	13651371	0.00%	$383	$1,576,594	$8,000	$630,614	$754,443
28	13651423	0.27%	$383	$375,188	$8,000	$119,664	$161,441
28	13651815	0.00%	$383	$1,576,594	$8,000	$627,061	$750,823
28	13652033	1.93%	$1,746	$69,125	$0	$42,754	$64,512
28	13652310	0.02%	$383	$375,188	$8,000	$150,327	$181,080
28	13652409	0.02%	$383	$375,188	$8,000	$150,676	$181,413
28	13652971	0.04%	$383	$60,938	$8,000	$26,542	$32,221
28	13653024	3.46%	$1,746	$612,349	$0	$14,218	$51,296
28	13653347	1.07%	$1,746	$69,125	$0	$39,948	$56,951
28	13653382	2.42%	$1,746	$59,250	$0	$21,858	$34,622
28	13653413	0.26%	$1,746	$88,875	$0	$53,601	$68,850
28	13653451	1.73%	$1,746	$1,660,679	$0	$177,053	$356,593
28	13653481	1.15%	$1,746	$1,660,679	$0	$303,654	$505,379
28	13653532	0.87%	$1,746	$79,000	$0	$35,684	$49,536
28	13653562	0.95%	$1,746	$69,125	$0	$39,865	$56,159
28	13653731	2.17%	$1,746	$88,875	$0	$41,993	$66,807
28	13653757	3.22%	$1,746	$88,875	$0	$44,009	$74,031
28	13653774	3.77%	$1,746	$79,000	$0	$29,499	$52,082
28	13653806	1.25%	$1,746	$88,875	$0	$42,290	$62,503

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES ON ISSUE 2.2

Job #	Asset Identifier	Failure Probability	Direct Cost ($)	Indirect Cost ($)		PV (2015 Cost of Deviation from Optimal) ($)	2012 Cost of Deviation from Optimal ($)
				Customer Interruption Cost ($)	Other Indirect Cost ($)		
28	13653810	1.24%	$1,746	$1,660,679	$0	$278,279	$476,518
28	14063514	9.29%	$458	$0	$5,000	$132,423	$0
28	14063517	3.26%	$795	$0	$5,000	$1,284	$10,385
28	14063519	6.75%	$458	$0	$5,000	$7,729	$0
28	14063603	1.63%	$416	$0	$5,000	$551,538	$0
28	14063696	3.68%	$458	$0	$5,000	$149,328	$0
28	14069005	9.29%	$458	$0	$5,000	$132,423	$0
28	14069015	9.29%	$458	$0	$5,000	$132,423	$0
28	14075023	1.48%	$745	$0	$4,500	$764	$1,927
28	14075024	1.32%	$408	$0	$4,500	$61,237	$0
28	14075025	1.32%	$408	$0	$4,500	$61,237	$0
28	14075363	1.17%	$408	$0	$4,500	$54,114	$0
28	14075364	1.17%	$408	$0	$4,500	$54,114	$0
28	14075365	1.83%	$408	$0	$4,500	$85,727	$0
28	14075366	1.83%	$408	$0	$4,500	$85,727	$0
28	14075511	1.32%	$408	$0	$4,500	$61,237	$0
28	14075512	1.32%	$408	$0	$4,500	$61,237	$0
28	14083858	1.32%	$408	$0	$4,500	$12,103	$0
28	14083859	1.32%	$408	$0	$4,500	$12,103	$0
28	14083860	1.32%	$408	$0	$4,500	$12,103	$0
28	14083861	1.32%	$408	$0	$4,500	$12,103	$0
28	14083869	1.32%	$783	$0	$4,000	$1,274	$788
28	14083870	1.32%	$783	$0	$4,000	$1,274	$788
28	14083872	2.23%	$408	$0	$4,500	$22,543	$0
28	14083873	2.23%	$408	$0	$4,500	$22,543	$0
28	14083874	1.32%	$408	$0	$4,500	$20,376	$0

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES ON ISSUE 2.2

Job #	Asset Identifier	Failure Probability	Direct Cost ($)	Indirect Cost ($)		PV (2015 Cost of Deviation from Optimal) ($)	2012 Cost of Deviation from Optimal ($)
				Customer Interruption Cost ($)	Other Indirect Cost ($)		
28	14083875	1.32%	$408	$0	$4,500	$20,376	$0
28	14083877	3.44%	$408	$0	$4,500	$57,365	$0
28	14083878	3.44%	$408	$0	$4,500	$57,365	$0
28	14083879	1.65%	$783	$0	$4,000	$4,844	$0
28	14083880	1.65%	$783	$0	$4,000	$4,844	$0
28	14083881	2.23%	$408	$0	$4,500	$22,543	$0
28	14083882	2.23%	$408	$0	$4,500	$22,543	$0
28	14083883	1.32%	$441	$0	$4,500	$231,720	$0
28	14083884	1.32%	$441	$0	$4,500	$248,479	$0
28	14083893	3.44%	$408	$0	$4,500	$57,365	$0
28	14083894	3.44%	$408	$0	$4,500	$57,365	$0
28	14083903	0.61%	$441	$0	$4,500	$105,447	$0
28	14083904	0.61%	$441	$0	$4,500	$105,447	$0
28	14083905	2.92%	$408	$0	$4,500	$5,566	$0
28	14083906	2.92%	$408	$0	$4,500	$5,566	$0
28	14083907	1.65%	$408	$0	$4,500	$1,793	$0
28	14083908	1.65%	$408	$0	$4,500	$1,793	$0
28	14118393	4.65%	$540	$0	$4,000	$8,298	$0
28	14118394	4.65%	$540	$0	$4,000	$8,298	$0
28	14118395	4.65%	$540	$0	$4,000	$8,298	$0
28	14118439	1.42%	$540	$0	$4,000	$448	$206
28	14118440	2.44%	$540	$0	$4,000	$1,121	$0
28	14118441	2.44%	$540	$0	$4,000	$1,121	$0
28	14118482	4.33%	$540	$0	$4,000	$8,949	$0
28	14118483	0.27%	$540	$0	$4,000	$3,331	$6,762
28	14118485	0.20%	$540	$0	$4,000	$4,082	$7,735

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES ON ISSUE 2.2

Job #	Asset Identifier	Failure Probability	Direct Cost ($)	Indirect Cost ($)		PV (2015 Cost of Deviation from Optimal) ($)	2012 Cost of Deviation from Optimal ($)
				Customer Interruption Cost ($)	Other Indirect Cost ($)		
28	14118546	0.20%	$540	$0	$4,000	$3,759	$7,458
28	14118565	2.00%	$540	$0	$4,000	$890	$0
28	14118591	0.05%	$540	$0	$4,000	$6,251	$10,494
28	14131006	3.18%	$540	$0	$4,000	$31,603	$0
28	14131042	0.05%	$540	$0	$4,000	$6,718	$10,743
28	14131043	4.65%	$540	$0	$4,000	$9,853	$0
28	14131051	4.76%	$540	$0	$4,000	$3,206	$5,838
28	14131070	2.25%	$540	$0	$4,000	$21,030	$33,210
28	14131073	2.68%	$540	$0	$4,000	$24,459	$0
28	14131074	2.25%	$540	$0	$4,000	$21,030	$33,210
28	14131075	3.39%	$540	$0	$4,000	$20,693	$31,683
28	14131076	2.25%	$540	$0	$4,000	$21,030	$33,210
28	14131091	4.76%	$540	$0	$4,000	$10,367	$16,835
28	14131107	1.19%	$540	$0	$4,000	$34,808	$49,799
28	14131108	4.18%	$540	$0	$4,000	$12,836	$19,947
28	14131113	2.68%	$540	$0	$4,000	$26,557	$38,821
28	14131181	1.08%	$540	$0	$4,000	$91	$702
28	14131691	2.25%	$540	$0	$4,000	$30,541	$43,575
28	28751615	1.87%	$1,746	$88,875	$0	$41,781	$65,078
28	28757390	0.00%	$383	$65,625	$8,000	$29,876	$35,820
28	28758756	4.22%	$1,746	$69,125	$0	$20,376	$37,351
28	28758761	5.16%	$1,746	$69,125	$0	$19,641	$37,949
28	28758874	4.45%	$1,746	$79,000	$0	$17,952	$35,441
28	28758909	3.36%	$1,746	$79,000	$0	$20,329	$36,600
28	28758911	0.98%	$1,746	$79,000	$0	$33,694	$47,287
28	28759258	8.83%	$1,746	$69,125	$0	$24,098	$51,424

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES ON ISSUE 2.2

Job #	Asset Identifier	Failure Probability	Direct Cost ($)	Indirect Cost ($)		PV (2015 Cost of Deviation from Optimal) ($)	2012 Cost of Deviation from Optimal ($)
				Customer Interruption Cost ($)	Other Indirect Cost ($)		
28	28759263	1.93%	$1,746	$69,125	$0	$26,895	$41,490
28	28759268	1.68%	$1,746	$69,125	$0	$27,796	$41,935
28	28759279	4.01%	$1,746	$69,125	$0	$23,545	$41,979
28	28759492	0.05%	$383	$75,000	$8,000	$29,588	$36,489
28	28759494	0.06%	$383	$75,000	$8,000	$28,819	$35,768
28	28759501	0.06%	$383	$75,000	$8,000	$28,887	$35,832
28	28759507	0.06%	$383	$75,000	$8,000	$29,076	$36,009
28	28759511	0.04%	$383	$75,000	$8,000	$30,374	$37,228
28	28759516	0.05%	$383	$75,000	$8,000	$29,308	$36,227
28	28759523	0.13%	$383	$75,000	$8,000	$25,410	$32,595
28	28759526	0.03%	$383	$65,625	$8,000	$27,532	$33,617
28	28759544	0.05%	$383	$65,625	$8,000	$26,464	$32,619
28	28759570	0.11%	$383	$65,625	$8,000	$23,636	$30,000
28	28759591	0.03%	$383	$65,625	$8,000	$27,599	$33,680
28	28759601	0.14%	$383	$65,625	$8,000	$22,517	$28,976
28	28759608	0.05%	$383	$65,625	$8,000	$26,436	$32,593
28	28759613	0.07%	$383	$65,625	$8,000	$25,213	$31,455
28	28759616	0.09%	$383	$65,625	$8,000	$24,398	$30,701
28	28759917	4.17%	$1,746	$79,000	$0	$50,397	$84,873
28	28759922	0.89%	$1,746	$79,000	$0	$41,783	$58,965
28	28759927	0.08%	$383	$75,000	$8,000	$27,660	$34,685
28	28759931	0.09%	$383	$75,000	$8,000	$27,192	$34,250
28	28759936	0.09%	$383	$75,000	$8,000	$27,280	$34,331
28	28759942	0.07%	$383	$75,000	$8,000	$28,160	$35,152
28	28759947	0.04%	$383	$75,000	$8,000	$30,252	$37,113
28	28759951	0.03%	$383	$75,000	$8,000	$31,447	$38,239

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES ON ISSUE 2.2

Job #	Asset Identifier	Failure Probability	Direct Cost ($)	Indirect Cost ($)		PV (2015 Cost of Deviation from Optimal) ($)	2012 Cost of Deviation from Optimal ($)
				Customer Interruption Cost ($)	Other Indirect Cost ($)		
28	28761086	1.74%	$1,746	$64,188	$0	$25,645	$38,646
28	28761090	4.24%	$1,746	$64,188	$0	$21,196	$38,075
28	28761119	1.24%	$1,746	$64,188	$0	$28,188	$40,414
28	28761124	4.70%	$1,746	$64,188	$0	$21,114	$38,710
28	28761127	1.36%	$1,746	$64,188	$0	$27,421	$39,840
28	28761149	1.85%	$1,746	$64,188	$0	$25,282	$38,456
28	28761153	1.17%	$1,746	$59,250	$0	$27,743	$39,302
28	28761160	3.11%	$1,746	$59,250	$0	$22,764	$37,611
28	28761164	1.73%	$1,746	$59,250	$0	$25,392	$37,888
28	28761183	3.02%	$1,746	$59,250	$0	$22,791	$37,473
28	28761188	2.22%	$1,746	$59,250	$0	$24,136	$37,466
28	28761190	3.28%	$1,746	$59,250	$0	$22,717	$37,844
28	28761688	0.65%	$1,746	$88,875	$0	$45,661	$62,876
28	28761705	1.14%	$1,746	$88,875	$0	$42,445	$62,118
28	28761737	2.10%	$1,746	$88,875	$0	$41,798	$66,218
28	28761746	1.81%	$1,746	$88,875	$0	$41,681	$64,678
28	28761778	2.12%	$1,746	$88,875	$0	$31,048	$50,081
28	28761786	0.23%	$1,746	$88,875	$0	$57,469	$71,286
28	28761850	2.64%	$1,746	$88,875	$0	$29,690	$49,963
28	28761856	1.70%	$1,746	$88,875	$0	$32,920	$50,933
28	28761858	2.14%	$1,746	$88,875	$0	$30,991	$50,077
28	28761865	1.32%	$1,746	$88,875	$0	$35,263	$52,368
28	28761942	0.62%	$1,746	$88,875	$0	$46,102	$63,154
28	28761951	0.80%	$1,746	$88,875	$0	$44,244	$62,219
28	28761966	1.40%	$1,746	$88,875	$0	$34,579	$51,884
28	28761971	2.50%	$1,746	$88,875	$0	$29,944	$49,880

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES ON ISSUE 2.2

Job #	Asset Identifier	Failure Probability	Direct Cost ($)	Indirect Cost ($)		PV (2015 Cost of Deviation from Optimal) ($)	2012 Cost of Deviation from Optimal ($)
				Customer Interruption Cost ($)	Other Indirect Cost ($)		
28	28761973	2.81%	$1,746	$88,875	$0	$29,133	$49,818
28	28761982	0.83%	$1,746	$79,000	$0	$37,711	$52,437
28	28761988	2.12%	$1,746	$79,000	$0	$31,152	$49,310
28	28761993	1.47%	$1,746	$79,000	$0	$33,088	$49,512
28	28761997	3.56%	$1,746	$79,000	$0	$22,550	$40,595
28	28762002	0.93%	$1,746	$79,000	$0	$34,908	$48,852
28	28762007	2.11%	$1,746	$79,000	$0	$26,358	$42,143
28	28762011	3.18%	$1,746	$79,000	$0	$23,371	$40,821
28	28762015	1.16%	$1,746	$79,000	$0	$32,483	$46,786
28	28762060	0.83%	$1,746	$88,875	$0	$44,089	$62,205
28	28762137	0.74%	$1,746	$88,875	$0	$44,839	$62,478
28	28762157	0.77%	$1,746	$88,875	$0	$44,590	$62,406
28	28763231	2.88%	$458	$0	$5,000	$735	$4,123
28	28763380	1.90%	$1,746	$79,000	$0	$24,530	$38,446
28	28763403	1.02%	$1,746	$79,000	$0	$32,584	$45,845
28	28763408	1.96%	$1,746	$79,000	$0	$24,176	$38,142
28	28763412	0.79%	$1,746	$79,000	$0	$36,006	$49,093
28	28763416	1.97%	$1,746	$79,000	$0	$24,140	$38,111
28	28763421	0.60%	$1,746	$79,000	$0	$39,556	$52,504
28	28763437	1.00%	$1,746	$79,000	$0	$32,845	$46,090
28	28763441	1.00%	$1,746	$79,000	$0	$32,824	$46,070
28	28763446	0.81%	$1,746	$79,000	$0	$35,781	$48,879
28	28763451	2.21%	$1,746	$59,250	$0	$22,433	$34,916
28	28763461	2.02%	$1,746	$59,250	$0	$26,348	$40,219
28	28763463	1.64%	$1,746	$59,250	$0	$27,192	$40,256
28	28763467	2.34%	$1,746	$59,250	$0	$25,943	$40,509

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES ON ISSUE 2.2

Job #	Asset Identifier	Failure Probability	Direct Cost ($)	Indirect Cost ($)		PV (2015 Cost of Deviation from Optimal) ($)	2012 Cost of Deviation from Optimal ($)
				Customer Interruption Cost ($)	Other Indirect Cost ($)		
28	28763472	1.51%	$1,746	$59,250	$0	$27,580	$40,375
28	28764986	4.00%	$1,746	$69,125	$0	$54,022	$87,284
28	28765163	1.70%	$1,746	$88,875	$0	$41,844	$64,268
28	28765253	0.95%	$1,746	$88,875	$0	$43,375	$62,086
28	28765301	0.60%	$1,746	$88,875	$0	$46,268	$63,239
28	28766299	1.22%	$1,746	$88,875	$0	$42,331	$62,401
28	28766339	1.55%	$1,746	$88,875	$0	$41,735	$63,434
28	28766495	0.93%	$1,746	$88,875	$0	$43,464	$62,065
28	28766575	1.83%	$1,746	$88,875	$0	$41,709	$64,793
28	28766632	1.83%	$1,746	$69,125	$0	$42,300	$63,531
28	28766643	0.98%	$1,746	$69,125	$0	$39,910	$56,372
28	28769536	2.09%	$1,746	$49,375	$0	$29,062	$43,283
28	28769550	5.32%	$1,746	$49,375	$0	$36,509	$60,181
28	28769552	3.50%	$1,746	$49,375	$0	$31,849	$50,197
28	28769556	1.78%	$1,746	$49,375	$0	$28,702	$42,015
28	28769562	2.10%	$1,746	$49,375	$0	$26,410	$39,601
28	28769564	1.58%	$1,746	$79,000	$0	$29,224	$44,187
28	28769568	1.97%	$1,746	$79,000	$0	$27,082	$42,657
28	28769638	1.82%	$1,746	$79,000	$0	$27,901	$43,231
28	28769660	2.10%	$1,746	$79,000	$0	$26,370	$42,149
28	28769662	2.79%	$1,746	$79,000	$0	$26,946	$45,220
28	28769673	1.14%	$1,746	$79,000	$0	$33,718	$48,579
28	28769679	1.42%	$1,746	$79,000	$0	$31,701	$47,147
28	28769691	0.67%	$1,746	$79,000	$0	$39,097	$52,987
28	28769735	1.92%	$1,746	$79,000	$0	$29,168	$45,651
28	28781212	0.91%	$1,746	$88,875	$0	$43,557	$62,043

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES ON ISSUE 2.2

Job #	Asset Identifier	Failure Probability	Direct Cost ($)	Indirect Cost ($)		PV (2015 Cost of Deviation from Optimal) ($)	2012 Cost of Deviation from Optimal ($)
				Customer Interruption Cost ($)	Other Indirect Cost ($)		
28	28781217	1.29%	$1,746	$88,875	$0	$42,011	$62,394
28	28781230	1.75%	$1,746	$88,875	$0	$41,572	$64,246
28	28781246	1.43%	$1,746	$98,750	$0	$42,574	$64,728
28	28781248	1.52%	$1,746	$98,750	$0	$42,428	$65,021
28	28781260	1.88%	$1,746	$98,750	$0	$41,531	$65,806
28	28781266	0.45%	$1,746	$98,750	$0	$52,139	$69,688
28	28781310	1.18%	$1,746	$98,750	$0	$43,762	$64,720
28	28781321	1.56%	$1,746	$98,750	$0	$42,375	$65,127
28	28781323	1.29%	$1,746	$98,750	$0	$43,181	$64,657
28	28781332	1.73%	$1,746	$98,750	$0	$41,951	$65,504
28	28781346	1.34%	$1,746	$98,750	$0	$43,039	$64,751
28	28781355	1.85%	$1,746	$98,750	$0	$41,896	$66,050
28	28781363	1.70%	$1,746	$88,875	$0	$41,846	$64,285
28	28781371	1.49%	$1,746	$88,875	$0	$41,954	$63,327
28	28781393	0.02%	$383	$75,000	$8,000	$31,649	$38,697
28	28781398	0.08%	$383	$75,000	$8,000	$28,390	$36,199
28	28781431	0.05%	$383	$75,000	$8,000	$29,741	$37,055
28	28781434	0.03%	$383	$75,000	$8,000	$31,279	$38,394
28	28781512	0.02%	$383	$75,000	$8,000	$31,589	$38,648
28	28781523	0.02%	$383	$75,000	$8,000	$31,762	$38,790
28	28781528	0.03%	$383	$75,000	$8,000	$31,195	$38,326
28	28781530	0.00%	$383	$75,000	$8,000	$33,911	$40,593
28	28781532	0.02%	$383	$75,000	$8,000	$31,501	$38,575
28	28781561	0.02%	$383	$93,750	$8,000	$38,045	$46,663
28	28781854	0.01%	$383	$93,750	$8,000	$39,627	$48,013
28	28782048	0.00%	$383	$93,750	$8,000	$41,475	$49,614

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES ON ISSUE 2.2

Job #	Asset Identifier	Failure Probability	Direct Cost ($)	Indirect Cost ($)		PV (2015 Cost of Deviation from Optimal) ($)	2012 Cost of Deviation from Optimal ($)
				Customer Interruption Cost ($)	Other Indirect Cost ($)		
28	28782054	0.01%	$383	$93,750	$8,000	$40,668	$48,895
28	28782091	0.00%	$383	$93,750	$8,000	$41,485	$49,623
28	28782161	0.00%	$383	$93,750	$8,000	$41,490	$49,627
28	28782238	0.00%	$1,746	$98,750	$0	$80,986	$96,886
28	28783711	3.51%	$1,746	$39,500	$0	$36,844	$54,965
28	28792986	2.88%	$1,746	$70,804	$0	$47,133	$74,254
28	28800882	0.00%	$383	$65,625	$8,000	$29,878	$35,821
28	28833986	0.03%	$383	$75,000	$8,000	$30,799	$37,627
28	28833988	0.13%	$383	$75,000	$8,000	$25,492	$32,670
28	28841369	0.07%	$1,746	$70,804	$0	$52,224	$63,842
28	30314463	0.03%	$383	$89,063	$8,000	$40,444	$48,752
28	30314488	0.03%	$383	$89,063	$8,000	$40,407	$48,715
28	30314514	0.02%	$383	$84,469	$8,000	$38,995	$46,941
28	30323259	0.08%	$1,746	$69,125	$0	$50,867	$62,261
28	30323274	0.00%	$383	$65,625	$8,000	$29,872	$35,815
28	30324251	0.23%	$1,746	$69,125	$0	$45,994	$57,023
28	30324282	0.26%	$1,746	$69,125	$0	$44,947	$55,975
28	30324311	0.27%	$1,746	$69,125	$0	$44,735	$55,763
28	30325142	0.46%	$1,746	$88,875	$0	$48,529	$64,760
28	30325647	0.00%	$383	$75,000	$8,000	$33,914	$40,596
28	30327380	0.25%	$1,746	$59,250	$0	$39,822	$49,461
28	30328641	0.33%	$1,746	$49,375	$0	$32,406	$40,702
28	30328681	0.25%	$1,746	$49,375	$0	$34,263	$42,512
28	30329715	0.00%	$383	$84,375	$8,000	$37,482	$44,893
28	30332635	0.23%	$1,746	$79,000	$0	$51,916	$64,340
28	30332907	0.25%	$1,746	$64,188	$0	$42,769	$53,102

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES ON ISSUE 2.2

Job #	Asset Identifier	Failure Probability	Direct Cost ($)	Indirect Cost ($)		PV (2015 Cost of Deviation from Optimal) ($)	2012 Cost of Deviation from Optimal ($)
				Customer Interruption Cost ($)	Other Indirect Cost ($)		
28	30333022	0.25%	$1,746	$59,250	$0	$39,822	$49,461
28	30333033	0.28%	$1,746	$64,188	$0	$41,812	$52,149
28	30333496	0.31%	$1,746	$64,188	$0	$40,755	$51,096
28	30333710	0.25%	$1,746	$88,875	$0	$56,719	$70,527
28	30333788	0.25%	$1,746	$64,188	$0	$42,755	$53,088
28	30333829	0.00%	$1,746	$70,804	$0	$172,664	$217,563
28	30334302	0.25%	$1,746	$88,875	$0	$56,593	$70,399
28	30334352	0.31%	$1,746	$64,188	$0	$40,845	$51,186
28	30439463	0.76%	$1,746	$98,750	$0	$46,940	$65,937
28	30439632	1.44%	$1,746	$98,750	$0	$42,563	$64,750
28	30439645	0.65%	$1,746	$98,750	$0	$48,482	$66,956
28	30440349	2.55%	$1,746	$98,750	$0	$41,755	$69,177
28	30440442	0.77%	$1,746	$98,750	$0	$46,868	$65,903
28	30440752	1.03%	$1,746	$98,750	$0	$44,604	$64,892
28	30440799	0.04%	$383	$84,469	$8,000	$38,096	$46,007
28	30440831	0.03%	$383	$581,344	$8,000	$225,942	$272,480
28	30441238	0.02%	$383	$375,188	$8,000	$148,801	$179,332
28	30441381	0.04%	$383	$75,000	$8,000	$30,589	$37,430
28	30441463	4.60%	$1,746	$79,000	$0	$52,647	$89,413
28	30441536	1.23%	$1,746	$79,000	$0	$41,111	$60,096
28	30441559	0.76%	$1,746	$69,125	$0	$40,039	$55,321
28	30441675	0.05%	$383	$75,000	$8,000	$29,756	$36,647
28	30441716	0.09%	$383	$75,000	$8,000	$26,966	$34,038
28	30441727	0.93%	$1,746	$79,000	$0	$41,697	$59,106
28	30441935	0.12%	$383	$75,000	$8,000	$25,956	$33,100
28	30441975	0.13%	$383	$75,000	$8,000	$25,479	$32,659

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES ON ISSUE 2.2

Job #	Asset Identifier	Failure Probability	Direct Cost ($)	Indirect Cost ($)		PV (2015 Cost of Deviation from Optimal) ($)	2012 Cost of Deviation from Optimal ($)
				Customer Interruption Cost ($)	Other Indirect Cost ($)		
28	30442011	0.06%	$383	$65,625	$8,000	$25,919	$32,111
28	30442222	1.34%	$1,746	$98,750	$0	$43,026	$64,760
28	30442311	0.01%	$383	$65,625	$8,000	$29,654	$35,608
28	30442352	0.12%	$383	$75,000	$8,000	$25,950	$33,094
28	30442399	0.60%	$1,746	$79,000	$0	$43,493	$59,139
28	30442412	0.01%	$383	$1,576,594	$8,000	$621,157	$745,763
28	30442517	1.28%	$1,746	$98,750	$0	$43,188	$64,652
28	30442570	0.76%	$1,746	$98,750	$0	$47,119	$66,102
28	30442689	0.21%	$383	$65,625	$8,000	$20,528	$27,177
28	30442716	0.10%	$383	$65,625	$8,000	$24,077	$30,406
28	30442912	0.10%	$383	$65,625	$8,000	$23,741	$30,097
28	30442981	1.44%	$1,746	$98,750	$0	$42,566	$64,744
28	30442983	1.25%	$1,746	$98,750	$0	$43,272	$64,596
28	30443027	0.92%	$1,746	$69,125	$0	$39,832	$56,002
28	30443028	0.12%	$383	$65,625	$8,000	$23,323	$29,713
28	30443107	2.19%	$1,746	$98,750	$0	$41,710	$67,444
28	30443184	1.17%	$1,746	$88,875	$0	$42,410	$62,204
28	30443189	1.72%	$1,746	$88,875	$0	$41,862	$64,408
28	30443234	0.92%	$1,746	$88,875	$0	$43,524	$62,051
28	30443237	0.01%	$383	$1,576,594	$8,000	$622,565	$747,121
28	30443239	0.00%	$383	$1,576,594	$8,000	$627,649	$751,391
28	30443292	0.03%	$383	$89,063	$8,000	$39,987	$48,256
28	30443294	0.03%	$416	$5,646,488	$8,000	$1,983,977	$2,397,124
28	30443331	0.03%	$416	$5,646,488	$8,000	$2,003,863	$2,418,804
28	30443335	0.03%	$383	$375,188	$8,000	$147,246	$177,766
28	30444491	0.10%	$383	$65,625	$8,000	$23,723	$30,080

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES ON ISSUE 2.2

Job #	Asset Identifier	Failure Probability	Direct Cost ($)	Indirect Cost ($)		PV (2015 Cost of Deviation from Optimal) ($)	2012 Cost of Deviation from Optimal ($)
				Customer Interruption Cost ($)	Other Indirect Cost ($)		
28	30444497	0.01%	$383	$65,625	$8,000	$29,818	$35,764
28	30444688	0.08%	$383	$103,125	$8,000	$36,796	$46,045
28	30444732	0.08%	$383	$103,125	$8,000	$36,273	$45,549
28	30444733	0.88%	$1,746	$108,625	$0	$47,831	$68,618
28	30444734	0.09%	$1,746	$108,625	$0	$75,321	$92,495
28	30444834	0.38%	$1,746	$108,625	$0	$57,799	$76,376
28	30444835	1.00%	$1,746	$108,625	$0	$46,622	$67,909
28	30444864	0.60%	$1,746	$108,625	$0	$52,185	$71,728
28	30444970	2.04%	$1,746	$108,625	$0	$41,163	$67,083
28	30444995	2.09%	$1,746	$108,625	$0	$41,151	$67,297
28	30445028	0.37%	$1,746	$108,625	$0	$58,282	$76,800
28	30445040	1.92%	$1,746	$108,625	$0	$41,749	$67,115
28	30445047	1.80%	$1,746	$108,625	$0	$41,901	$66,756
28	30445317	1.35%	$1,746	$108,625	$0	$43,832	$66,670
28	30445360	0.06%	$383	$75,000	$8,000	$29,334	$36,211
28	30445393	1.05%	$1,746	$79,000	$0	$41,436	$59,466
28	30445464	1.36%	$1,746	$69,125	$0	$40,644	$59,257
28	30445514	1.06%	$1,746	$69,125	$0	$39,902	$56,801
28	30445545	0.06%	$383	$65,625	$8,000	$25,997	$32,184
28	30445596	1.92%	$1,746	$69,125	$0	$42,719	$64,435
28	30445611	2.30%	$1,746	$69,125	$0	$44,464	$68,271
28	30445641	0.07%	$383	$65,625	$8,000	$25,240	$31,481
28	30445699	0.16%	$383	$65,625	$8,000	$21,751	$28,278
28	30445721	0.02%	$383	$65,625	$8,000	$28,341	$34,376
28	30445759	0.08%	$383	$65,625	$8,000	$24,810	$31,083
28	30445786	0.07%	$383	$75,000	$8,000	$28,101	$35,097

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES ON ISSUE 2.2

Job #	Asset Identifier	Failure Probability	Direct Cost ($)	Indirect Cost ($)		PV (2015 Cost of Deviation from Optimal) ($)	2012 Cost of Deviation from Optimal ($)
				Customer Interruption Cost ($)	Other Indirect Cost ($)		
28	30445818	0.13%	$383	$65,625	$8,000	$22,865	$29,293
28	30445836	0.56%	$1,746	$98,750	$0	$50,038	$68,074
28	30445847	0.36%	$1,746	$98,750	$0	$54,672	$71,775
28	30445897	4.43%	$1,746	$1,660,679	$0	$5,417	$54,169
28	30445945	0.02%	$383	$375,188	$8,000	$149,242	$179,777
28	30446002	0.65%	$1,746	$79,000	$0	$43,024	$58,970
28	30446256	0.73%	$1,746	$70,804	$0	$40,479	$55,794
28	30446311	1.05%	$1,746	$70,804	$0	$40,155	$57,231
28	30446371	0.77%	$1,746	$70,804	$0	$40,426	$55,957
28	30448773	0.00%	$416	$5,646,488	$8,000	$2,143,178	$2,694,756
28	30449590	0.00%	$416	$5,646,488	$8,000	$2,127,309	$2,650,876
28	30449611	0.00%	$416	$5,646,488	$8,000	$2,145,393	$2,565,274
28	30450805	0.00%	$416	$5,646,488	$8,000	$2,123,009	$2,579,973
28	30451667	1.63%	$491	$0	$5,000	$297,739	$0
28	30451671	0.00%	$383	$375,188	$8,000	$157,573	$191,042
28	30451784	0.00%	$416	$5,646,488	$8,000	$2,119,254	$2,621,498
28	30453457	0.00%	$416	$5,646,488	$8,000	$2,117,842	$2,604,819
28	30453530	0.00%	$720	$187,500	$8,000	$74,274	$90,278
28	30453791	0.00%	$383	$159,375	$8,000	$69,939	$84,830
28	30474423	2.52%	$383	$84,469	$8,000	$1,398	$4,954
28	30506147	4.65%	$540	$0	$4,000	$9,853	$0
28	30506154	0.00%	$383	$75,000	$8,000	$34,398	$41,084
28	30506156	0.00%	$383	$75,000	$8,000	$34,399	$41,086
28	30506819	0.00%	$383	$65,625	$8,000	$30,615	$36,561
28	30506824	4.65%	$540	$0	$4,000	$8,298	$0
28	30507386	0.00%	$383	$84,375	$8,000	$38,153	$45,565

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES ON ISSUE 2.2

Job #	Asset Identifier	Failure Probability	Direct Cost ($)	Indirect Cost ($)		PV (2015 Cost of Deviation from Optimal) ($)	2012 Cost of Deviation from Optimal ($)
				Customer Interruption Cost ($)	Other Indirect Cost ($)		
28	30507448	1.60%	$540	$0	$4,000	$963	$0
28	30507479	0.00%	$383	$84,375	$8,000	$38,152	$45,563
28	30507879	0.00%	$383	$84,375	$8,000	$38,148	$45,556
28	30509381	0.00%	$383	$84,375	$8,000	$38,147	$45,555
28	30509445	4.03%	$540	$0	$4,000	$8,075	$0
28	30509454	0.00%	$383	$75,000	$8,000	$34,331	$41,021
28	30509805	4.33%	$540	$0	$4,000	$8,949	$0
28	30514732	2.00%	$540	$0	$4,000	$890	$0
28	30514796	2.00%	$540	$0	$4,000	$890	$0
28	30514799	0.00%	$383	$56,250	$8,000	$26,858	$32,076
28	30514848	4.65%	$540	$0	$4,000	$6,755	$0
28	30514851	0.00%	$383	$56,250	$8,000	$26,853	$32,069
28	30514871	2.00%	$540	$0	$4,000	$890	$0
28	30514885	4.65%	$540	$0	$4,000	$6,755	$0
28	30514886	0.00%	$383	$56,250	$8,000	$26,855	$32,071
28	30514896	0.00%	$383	$56,250	$8,000	$26,861	$32,080
28	30514900	0.00%	$383	$56,250	$8,000	$26,852	$32,067
28	30522399	1.79%	$540	$0	$4,000	$1,541	$0
28	30522401	0.00%	$383	$75,000	$8,000	$34,392	$41,075
28	30522478	1.79%	$540	$0	$4,000	$1,541	$0
28	30522485	0.00%	$383	$75,000	$8,000	$34,399	$41,086
28	30523549	0.00%	$383	$75,000	$8,000	$34,399	$41,087
28	30523565	0.00%	$383	$75,000	$8,000	$34,393	$41,076
28	30523579	0.00%	$383	$75,000	$8,000	$34,393	$41,076
28	30523598	0.00%	$383	$75,000	$8,000	$34,395	$41,080
28	30524157	0.00%	$383	$75,000	$8,000	$34,384	$41,063

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES ON ISSUE 2.2

Job #	Asset Identifier	Failure Probability	Direct Cost ($)	Indirect Cost ($)		PV (2015 Cost of Deviation from Optimal) ($)	2012 Cost of Deviation from Optimal ($)
				Customer Interruption Cost ($)	Other Indirect Cost ($)		
28	30525378	2.44%	$540	$0	$4,000	$1,121	$0
28	30525458	2.44%	$540	$0	$4,000	$1,121	$0
28	30525459	0.00%	$383	$46,875	$8,000	$23,092	$27,579
28	30525576	2.44%	$540	$0	$4,000	$1,121	$0
28	30525585	0.00%	$383	$46,875	$8,000	$23,100	$27,589
28	30525653	1.42%	$540	$0	$4,000	$448	$206
28	30525671	0.00%	$383	$75,000	$8,000	$34,393	$41,076
28	30525778	1.42%	$540	$0	$4,000	$448	$206
28	30525781	0.00%	$383	$75,000	$8,000	$34,387	$41,067
28	30525808	1.42%	$540	$0	$4,000	$448	$206
28	30525813	0.00%	$383	$75,000	$8,000	$34,398	$41,084
28	30525863	1.42%	$540	$0	$4,000	$448	$206
28	30525865	0.00%	$383	$75,000	$8,000	$34,398	$41,084
28	30525909	1.42%	$540	$0	$4,000	$448	$206
28	30525912	0.00%	$383	$75,000	$8,000	$34,394	$41,077
28	30525946	1.42%	$540	$0	$4,000	$448	$206
28	30525948	0.00%	$383	$75,000	$8,000	$34,394	$41,078
28	30525985	1.42%	$540	$0	$4,000	$448	$206
28	30525987	0.00%	$383	$75,000	$8,000	$34,393	$41,077
28	30526027	0.00%	$383	$60,938	$8,000	$28,746	$34,332
28	30526031	1.04%	$783	$0	$4,000	$11,834	$20,579
28	30526068	0.00%	$383	$56,250	$8,000	$26,851	$32,066
28	30526143	0.00%	$383	$56,250	$8,000	$26,859	$32,078
28	30526156	0.00%	$383	$56,250	$8,000	$26,856	$32,073
28	30526183	0.00%	$383	$56,250	$8,000	$26,856	$32,073
28	30538705	0.00%	$1,746	$44,438	$0	$117,979	$141,494

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES ON ISSUE 2.2

Job #	Asset Identifier	Failure Probability	Direct Cost ($)	Indirect Cost ($)		PV (2015 Cost of Deviation from Optimal) ($)	2012 Cost of Deviation from Optimal ($)
				Customer Interruption Cost ($)	Other Indirect Cost ($)		
28	30538809	0.00%	$416	$5,646,488	$8,000	$2,101,165	$2,554,858
28	30538829	0.00%	$383	$0	$8,000	$11,073	$13,327
28	30538917	0.00%	$416	$5,646,488	$8,000	$2,130,323	$2,571,818
28	30551128	0.48%	$1,746	$1,660,679	$0	$776,803	$1,050,308
28	30552103	0.00%	$383	$375,188	$8,000	$159,930	$195,311
28	30559416	0.08%	$1,746	$98,750	$0	$70,220	$85,914
28	30559443	0.93%	$1,746	$98,750	$0	$45,378	$65,190
28	30559445	3.99%	$1,746	$98,750	$0	$43,853	$78,061
28	30571295	0.28%	$1,746	$64,188	$0	$41,561	$51,898
28	30571344	0.01%	$383	$60,938	$8,000	$27,841	$33,406
28	30571473	0.32%	$1,746	$64,188	$0	$40,580	$50,921
29	13618398	0.05%	$383	$431,344	$8,000	$161,221	$195,228
29	13618940	0.08%	$383	$244,125	$8,000	$92,244	$112,250
29	13620745	36.17%	$1,746	$454,349	$0	$426,155	$0
29	13622152	0.06%	$720	$22,500	$8,000	$11,545	$13,993
29	13622506	161.31%	$1,746	$14,813	$0	$73,221	$51,841
29	13622603	95.94%	$1,746	$257,145	$0	$691,332	$0
29	13623852	0.06%	$383	$431,344	$8,000	$161,461	$195,901
29	13624782	59.59%	$1,746	$103,688	$0	$155,407	$0
29	13624852	15.34%	$1,746	$14,813	$0	$0	$1,737
29	13624895	0.13%	$214	$2,968,875	$8,000	$1,472,832	$1,796,694
29	13625157	0.08%	$383	$244,125	$8,000	$92,894	$112,927
29	13625176	0.05%	$720	$450,000	$8,000	$104,872	$127,676
29	13625278	0.08%	$383	$244,125	$8,000	$92,579	$112,599
29	13626200	0.38%	$383	$244,125	$8,000	$63,087	$81,714
29	13629023	30.41%	$1,746	$454,349	$0	$347,212	$0

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Job #	Asset Identifier	Failure Probability	Direct Cost ($)	Indirect Cost ($)		PV (2015 Cost of Deviation from Optimal) ($)	2012 Cost of Deviation from Optimal ($)
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29	13629065	0.07%	$383	$244,125	$8,000	$93,077	$113,118
29	13629594	0.65%	$383	$431,344	$8,000	$76,275	$105,561
29	13629738	47.80%	$1,746	$257,145	$0	$324,384	$0
29	13630140	20.26%	$1,746	$257,145	$0	$114,651	$0
29	13631277	0.07%	$383	$431,344	$8,000	$159,561	$193,917
29	13631640	0.07%	$383	$244,125	$8,000	$93,575	$113,636
29	13631947	0.08%	$383	$431,344	$8,000	$158,773	$193,094
29	13633285	0.08%	$383	$431,344	$8,000	$158,576	$192,888
29	13633571	37.86%	$1,746	$257,145	$0	$248,658	$0
29	13633676	0.07%	$383	$244,125	$8,000	$93,889	$113,964
29	13634582	0.08%	$383	$431,344	$8,000	$157,626	$191,897
29	13636773	0.06%	$383	$98,438	$8,000	$42,047	$50,975
29	13637182	21.76%	$1,746	$454,349	$0	$228,919	$0
29	13637900	0.59%	$383	$431,344	$8,000	$82,155	$111,996
29	13639872	0.06%	$383	$431,344	$8,000	$161,407	$195,844
29	13639995	0.08%	$383	$244,125	$8,000	$92,234	$112,239
29	13640609	54.16%	$1,746	$454,349	$0	$672,558	$0
29	13641499	48.49%	$1,746	$257,145	$0	$329,667	$0
29	13641788	0.08%	$383	$244,125	$8,000	$92,284	$112,292
29	13641820	0.06%	$383	$98,438	$8,000	$42,002	$50,928
29	13641970	0.08%	$416	$4,457,963	$8,000	$1,469,031	$1,790,556
29	13642022	23.05%	$1,746	$454,349	$0	$246,558	$0
29	13642134	14.84%	$1,746	$257,145	$0	$73,436	$0
29	13643732	18.32%	$1,795	$4,794,413	$0	$2,036,472	$0
29	13644041	0.07%	$383	$431,344	$8,000	$159,275	$193,618
29	13644825	0.08%	$383	$244,125	$8,000	$92,579	$112,599

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES ON ISSUE 2.2

Job #	Asset Identifier	Failure Probability	Direct Cost ($)	Indirect Cost ($)		PV (2015 Cost of Deviation from Optimal) ($)	2012 Cost of Deviation from Optimal ($)
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29	13645233	7.98%	$2,233	$54,000	$0	$5,228	$0
29	13645855	47.42%	$1,746	$257,145	$0	$321,531	$0
29	13645877	40.53%	$1,746	$454,349	$0	$485,856	$0
29	13646273	63.76%	$1,746	$454,349	$0	$803,998	$0
29	13647300	0.19%	$416	$4,457,963	$8,000	$1,267,668	$1,579,870
29	13647688	44.15%	$1,746	$454,349	$0	$535,310	$0
29	13648609	0.07%	$383	$431,344	$8,000	$159,597	$193,955
29	13649779	3.11%	$1,746	$454,349	$0	$20,685	$49,850
29	13649905	0.07%	$383	$431,344	$8,000	$160,458	$194,853
29	13650193	0.12%	$214	$2,968,875	$8,000	$1,488,225	$1,812,798
29	13650391	0.07%	$383	$431,344	$8,000	$159,956	$194,329
29	13650901	0.08%	$383	$244,125	$8,000	$92,142	$112,144
29	13650915	0.07%	$383	$244,125	$8,000	$93,818	$113,890
29	13651060	38.74%	$1,746	$103,688	$0	$95,162	$0
29	13651953	0.08%	$383	$244,125	$8,000	$92,345	$112,356
29	13652516	0.07%	$383	$431,344	$8,000	$160,798	$195,208
29	13652743	0.08%	$383	$431,344	$8,000	$158,988	$193,319
29	13652930	0.19%	$720	$22,500	$8,000	$10,155	$12,608
29	14068035	0.36%	$458	$0	$5,000	$34,376	$61,725
29	14082141	1.83%	$408	$0	$4,500	$21,100	$0
29	14082142	2.92%	$408	$0	$4,500	$35,239	$0
29	14082143	4.32%	$408	$0	$4,500	$28,884	$0
29	14082144	5.98%	$408	$0	$4,500	$40,606	$0
29	14082145	7.49%	$408	$0	$4,500	$51,015	$0
29	14082150	4.01%	$408	$0	$4,500	$78,280	$0
29	14082151	4.32%	$408	$0	$4,500	$52,788	$0

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES ON ISSUE 2.2

Job #	Asset Identifier	Failure Probability	Direct Cost ($)	Indirect Cost ($)		PV (2015 Cost of Deviation from Optimal) ($)	2012 Cost of Deviation from Optimal ($)
				Customer Interruption Cost ($)	Other Indirect Cost ($)		
29	14082152	4.32%	$408	$0	$4,500	$52,788	$0
29	14082153	2.92%	$408	$0	$4,500	$35,239	$0
29	14082154	0.17%	$408	$0	$4,500	$681	$3,111
29	14082155	0.17%	$408	$0	$4,500	$681	$3,111
29	14082156	5.98%	$408	$0	$4,500	$40,606	$0
29	14082157	4.01%	$408	$0	$4,500	$26,735	$0
29	14082158	2.02%	$408	$0	$4,500	$12,246	$0
29	14082159	2.02%	$408	$0	$4,500	$12,246	$0
29	14082160	7.49%	$408	$0	$4,500	$51,015	$0
29	14082161	4.32%	$408	$0	$4,500	$28,884	$0
29	14082162	3.72%	$408	$0	$4,500	$24,657	$0
29	14082163	3.72%	$408	$0	$4,500	$24,657	$0
29	14082164	7.49%	$408	$0	$4,500	$19,696	$0
29	14082165	7.49%	$408	$0	$4,500	$19,696	$0
29	14082176	1.83%	$408	$0	$4,500	$21,100	$0
29	14082177	0.34%	$408	$0	$4,500	$624	$311
29	14082178	0.34%	$408	$0	$4,500	$624	$311
29	28779372	0.06%	$720	$22,500	$8,000	$11,542	$13,990
29	28779407	0.33%	$720	$450,000	$8,000	$59,409	$79,673
29	28779776	0.02%	$383	$431,344	$8,000	$166,789	$201,040
29	28779784	0.06%	$720	$45,000	$8,000	$16,437	$19,955
29	30309610	0.11%	$383	$14,063	$8,000	$11,394	$13,864
29	30309617	0.11%	$383	$98,438	$8,000	$40,100	$48,960
29	30322393	0.06%	$720	$22,500	$8,000	$11,549	$13,997
29	30322395	0.05%	$720	$22,500	$8,000	$11,584	$14,032
29	30324399	0.05%	$383	$244,125	$8,000	$95,616	$115,764

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES ON ISSUE 2.2

Job #	Asset Identifier	Failure Probability	Direct Cost ($)	Indirect Cost ($)		PV (2015 Cost of Deviation from Optimal) ($)	2012 Cost of Deviation from Optimal ($)
				Customer Interruption Cost ($)	Other Indirect Cost ($)		
29	30324403	0.05%	$383	$244,125	$8,000	$95,738	$115,891
29	30324405	0.49%	$383	$244,125	$8,000	$55,524	$73,643
30	1163214	0.50%	$195	$51,239	$385	$2,300	$2,937
30	1163215	0.26%	$195	$51,239	$385	$5,393	$6,407
30	1163224	0.50%	$282	$59,330	$385	$3,623	$5,708
30	1671793	0.00%	$214	$936,797	$8,000	$534,118	$639,498
30	1673364	0.00%	$214	$936,797	$8,000	$536,296	$641,513
30	1674270	0.00%	$214	$936,797	$8,000	$535,020	$640,333
30	1676871	0.00%	$214	$936,797	$8,000	$536,637	$641,828
30	1677058	1.02%	$1,746	$22,219	$0	$59,816	$77,973
30	1677260	0.48%	$1,746	$22,219	$0	$37,775	$48,541
30	1677393	0.05%	$1,746	$148,125	$0	$151,349	$184,029
30	1678975	0.06%	$1,746	$148,125	$0	$158,542	$193,195
30	1679074	0.75%	$1,746	$37,031	$0	$49,181	$65,539
30	1679643	0.24%	$1,746	$22,219	$0	$262,364	$316,165
30	1679867	0.03%	$1,746	$22,219	$0	$49,976	$60,039
30	1680026	1.52%	$1,746	$37,031	$0	$73,997	$100,667
30	1680185	0.06%	$1,746	$148,125	$0	$162,747	$198,544
30	1680268	0.10%	$1,746	$148,125	$0	$197,137	$242,133
30	1680339	0.04%	$1,746	$22,219	$0	$66,414	$79,862
30	1681690	0.00%	$383	$82,125	$8,000	$36,740	$43,997
30	1681900	0.07%	$1,746	$148,125	$0	$170,310	$208,153
30	1682388	0.06%	$1,746	$148,125	$0	$161,524	$196,989
30	1682889	0.02%	$1,746	$86,505	$0	$88,453	$106,577
30	1683961	0.03%	$1,746	$148,125	$0	$138,531	$167,616
30	1684430	0.04%	$1,746	$22,219	$0	$62,027	$74,571

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES ON ISSUE 2.2

Job #	Asset Identifier	Failure Probability	Direct Cost ($)	Indirect Cost ($)		PV (2015 Cost of Deviation from Optimal) ($)	2012 Cost of Deviation from Optimal ($)
				Customer Interruption Cost ($)	Other Indirect Cost ($)		
30	1684937	0.00%	$214	$936,797	$8,000	$536,157	$641,384
30	1685283	0.04%	$1,746	$86,505	$0	$105,474	$127,706
30	1685672	0.04%	$1,746	$148,125	$0	$149,217	$181,308
30	1686446	0.50%	$1,746	$22,219	$0	$38,645	$49,705
30	1686949	0.00%	$214	$936,797	$8,000	$534,899	$640,221
30	1687397	0.03%	$1,746	$148,125	$0	$142,430	$172,621
30	1687528	0.69%	$1,746	$22,219	$0	$46,187	$59,800
30	1688279	0.01%	$383	$82,125	$8,000	$35,989	$43,404
30	1689442	0.00%	$214	$936,797	$8,000	$536,625	$641,817
30	1690434	0.68%	$1,746	$22,219	$0	$45,826	$59,319
30	1690675	0.00%	$214	$936,797	$8,000	$535,512	$641,533
30	1690907	0.04%	$1,746	$148,125	$0	$142,760	$173,046
30	1691784	0.10%	$1,746	$148,125	$0	$197,570	$242,679
30	1692923	0.92%	$1,746	$37,031	$0	$54,418	$72,988
30	1693210	0.12%	$1,746	$148,125	$0	$208,499	$256,490
30	1694096	0.09%	$1,746	$148,125	$0	$184,530	$226,179
30	1695627	0.02%	$1,746	$22,219	$0	$38,823	$46,589
30	1697645	0.02%	$1,746	$86,505	$0	$87,861	$105,841
30	1701407	0.74%	$1,746	$22,219	$0	$48,194	$62,475
30	1701723	0.07%	$1,746	$148,125	$0	$168,941	$206,413
30	1703159	0.76%	$1,746	$22,219	$0	$49,204	$63,821
30	1704105	0.00%	$1,746	$148,125	$0	$119,958	$143,678
30	1704773	0.10%	$1,746	$22,219	$0	$121,107	$145,818
30	1705483	0.00%	$214	$936,797	$8,000	$536,436	$641,643
30	1706434	0.02%	$383	$35,156	$8,000	$17,857	$21,724
30	1707095	0.02%	$214	$936,797	$8,000	$516,176	$623,648

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES ON ISSUE 2.2

Job #	Asset Identifier	Failure Probability	Direct Cost ($)	Indirect Cost ($)		PV (2015 Cost of Deviation from Optimal) ($)	2012 Cost of Deviation from Optimal ($)
				Customer Interruption Cost ($)	Other Indirect Cost ($)		
30	1708317	0.11%	$1,746	$22,219	$0	$131,486	$158,335
30	1709023	0.13%	$1,746	$148,125	$0	$217,546	$267,918
30	1709827	0.05%	$1,746	$148,125	$0	$153,966	$187,367
30	1709939	0.05%	$1,746	$148,125	$0	$152,530	$185,535
30	1711157	0.76%	$1,746	$22,219	$0	$49,256	$63,891
30	1711180	0.03%	$1,746	$148,125	$0	$139,390	$168,720
30	1711320	2.80%	$1,746	$22,219	$0	$139,158	$181,928
30	1712108	0.05%	$1,746	$37,031	$0	$76,915	$92,731
30	1737682	2.00%	$540	$0	$4,000	$890	$0
30	1737683	2.00%	$540	$0	$4,000	$890	$0
30	1737684	2.00%	$540	$0	$4,000	$890	$0
30	1737713	1.68%	$540	$0	$2,000	$5,861	$0
30	1737714	1.68%	$540	$0	$2,000	$5,861	$0
30	1737715	1.68%	$540	$0	$2,000	$5,861	$0
30	1737716	1.68%	$540	$0	$2,000	$5,861	$0
30	1737717	1.68%	$540	$0	$2,000	$5,861	$0
30	1737718	2.00%	$540	$0	$4,000	$6,222	$0
30	1737719	2.00%	$540	$0	$4,000	$6,809	$0
30	1737720	2.00%	$540	$0	$4,000	$6,809	$0
30	1737721	2.00%	$540	$0	$4,000	$6,222	$0
30	1737722	2.00%	$540	$0	$4,000	$6,809	$0
30	1737723	1.68%	$540	$0	$2,000	$5,861	$0
30	1737724	1.68%	$540	$0	$2,000	$5,861	$0
30	1737740	2.00%	$540	$0	$4,000	$890	$0
30	1737790	2.00%	$540	$0	$4,000	$890	$0
30	1737791	2.00%	$540	$0	$4,000	$890	$0

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES ON ISSUE 2.2

Job #	Asset Identifier	Failure Probability	Direct Cost ($)	Indirect Cost ($)		PV (2015 Cost of Deviation from Optimal) ($)	2012 Cost of Deviation from Optimal ($)
				Customer Interruption Cost ($)	Other Indirect Cost ($)		
30	1737792	1.60%	$540	$0	$4,000	$137	$429
30	1737793	2.00%	$540	$0	$4,000	$890	$0
30	1737794	2.00%	$540	$0	$4,000	$890	$0
30	1737795	2.00%	$540	$0	$4,000	$890	$0
30	1737796	2.00%	$540	$0	$4,000	$890	$0
30	1737797	2.00%	$540	$0	$4,000	$890	$0
30	1737798	2.00%	$540	$0	$4,000	$890	$0
30	1737799	2.00%	$540	$0	$4,000	$890	$0
30	1737800	2.00%	$540	$0	$4,000	$890	$0
30	1737801	2.00%	$540	$0	$4,000	$890	$0
30	1737802	2.00%	$540	$0	$4,000	$1,356	$0
30	1737803	2.00%	$540	$0	$4,000	$1,356	$0
30	1737822	2.00%	$540	$0	$4,000	$1,356	$0
30	1737841	2.44%	$540	$0	$4,000	$291	$1,340
30	1737842	2.00%	$540	$0	$4,000	$1,356	$0
30	1737843	2.00%	$540	$0	$4,000	$1,356	$0
30	1737844	2.00%	$540	$0	$4,000	$1,356	$0
30	1737845	1.60%	$540	$0	$4,000	$387	$194
30	1737846	1.60%	$540	$0	$4,000	$387	$194
30	1737847	1.60%	$540	$0	$4,000	$387	$194
30	1737848	1.60%	$540	$0	$4,000	$1,484	$3,277
30	1737849	1.60%	$540	$0	$4,000	$1,484	$3,277
30	1737850	2.00%	$540	$0	$4,000	$801	$2,240
30	1737851	2.00%	$540	$0	$4,000	$6,809	$0
30	1737852	2.00%	$540	$0	$4,000	$6,809	$0
30	1737853	2.00%	$540	$0	$4,000	$6,809	$0

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES ON ISSUE 2.2

Job #	Asset Identifier	Failure Probability	Direct Cost ($)	Indirect Cost ($)		PV (2015 Cost of Deviation from Optimal) ($)	2012 Cost of Deviation from Optimal ($)
				Customer Interruption Cost ($)	Other Indirect Cost ($)		
30	1737854	2.00%	$540	$0	$4,000	$6,222	$0
30	1737855	2.00%	$540	$0	$4,000	$6,809	$0
30	1738277	3.18%	$540	$0	$4,000	$2,772	$0
30	1738278	3.18%	$540	$0	$4,000	$2,772	$0
30	1738336	3.18%	$540	$0	$4,000	$2,014	$0
30	1738344	2.92%	$540	$0	$4,000	$2,265	$0
30	1738345	3.18%	$540	$0	$4,000	$2,772	$0
30	1738353	4.65%	$540	$0	$4,000	$4,474	$0
30	1738359	3.18%	$540	$0	$4,000	$2,014	$0
30	1738361	1.60%	$540	$0	$4,000	$106	$1,128
30	1738363	1.60%	$540	$0	$4,000	$1,484	$3,277
30	1738364	1.60%	$540	$0	$4,000	$1,484	$3,277
30	1738420	3.74%	$540	$0	$4,000	$2,490	$0
30	1738614	6.71%	$540	$0	$2,000	$1,202	$0
30	1738616	5.06%	$540	$0	$2,000	$165	$79
30	1738627	2.00%	$540	$0	$4,000	$279	$108
30	1738629	2.00%	$540	$0	$4,000	$279	$108
30	1738630	1.42%	$540	$0	$4,000	$623	$2,176
30	1738633	3.46%	$540	$0	$4,000	$143	$137
30	1738634	3.46%	$540	$0	$4,000	$143	$137
30	1738635	1.42%	$540	$0	$4,000	$1,878	$3,833
30	1738698	1.60%	$540	$0	$4,000	$1,484	$3,277
30	1738699	2.44%	$540	$0	$4,000	$291	$1,340
30	1738717	3.46%	$540	$0	$4,000	$143	$137
30	28728090	0.00%	$214	$936,797	$8,000	$535,075	$640,384
31	13618872	1.08%	$416	$4,009,086	$8,000	$309,397	$538,977

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES ON ISSUE 2.2

Job #	Asset Identifier	Failure Probability	Direct Cost ($)	Indirect Cost ($)		PV (2015 Cost of Deviation from Optimal) ($)	2012 Cost of Deviation from Optimal ($)
				Customer Interruption Cost ($)	Other Indirect Cost ($)		
31	13620583	4.73%	$1,746	$138,250	$0	$10,369	$28,853
31	13620625	0.05%	$416	$4,009,086	$8,000	$1,344,383	$1,639,887
31	13621399	2.92%	$1,746	$88,875	$0	$20,967	$37,371
31	13621560	0.35%	$416	$4,009,086	$8,000	$770,474	$1,086,667
31	13622426	16.43%	$1,795	$4,311,658	$0	$1,691,449	$0
31	13623202	2.11%	$1,746	$79,000	$0	$24,652	$39,518
31	13623361	0.57%	$416	$4,009,086	$8,000	$614,302	$881,790
31	13623691	2.57%	$1,746	$24,688	$0	$27,847	$39,228
31	13625378	23.11%	$1,795	$4,311,658	$0	$2,625,399	$0
31	13625417	0.58%	$416	$4,009,086	$8,000	$563,774	$841,763
31	13625775	29.71%	$1,795	$4,311,658	$0	$3,552,122	$0
31	13626457	0.02%	$416	$4,009,086	$8,000	$1,433,785	$1,728,415
31	13628241	5.35%	$1,746	$69,125	$0	$19,130	$37,703
31	13628608	1.83%	$1,746	$69,125	$0	$25,559	$39,171
31	13631334	38.61%	$1,795	$4,311,658	$0	$4,802,148	$0
31	13633229	0.01%	$416	$4,009,086	$8,000	$1,465,541	$1,760,575
31	13633663	0.01%	$416	$4,009,086	$8,000	$1,467,474	$1,762,533
31	13635038	7.59%	$1,746	$90,554	$0	$11,663	$31,865
31	13636412	1.11%	$1,746	$88,875	$0	$34,104	$48,992
31	13638034	0.02%	$416	$4,009,086	$8,000	$1,448,490	$1,743,306
31	13638774	1.07%	$1,746	$88,875	$0	$34,722	$49,576
31	13639962	9.91%	$1,795	$4,311,658	$0	$781,297	$0
31	13643853	1.00%	$383	$28,125	$8,000	$5,579	$8,589
31	13644297	0.00%	$383	$131,250	$8,000	$55,641	$66,692
31	13645271	0.81%	$416	$4,009,086	$8,000	$389,994	$644,405
31	13646761	0.89%	$1,795	$4,311,658	$0	$1,010,303	$1,492,885

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES ON ISSUE 2.2

Job #	Asset Identifier	Failure Probability	Direct Cost ($)	Indirect Cost ($)		PV (2015 Cost of Deviation from Optimal) ($)	2012 Cost of Deviation from Optimal ($)
				Customer Interruption Cost ($)	Other Indirect Cost ($)		
31	13647089	2.30%	$1,746	$88,875	$0	$23,948	$39,836
31	13648173	5.87%	$1,795	$4,311,658	$0	$219,409	$0
31	13648815	0.14%	$383	$28,125	$8,000	$12,430	$15,461
31	13651269	0.09%	$383	$9,375	$8,000	$7,053	$8,636
31	13652551	0.88%	$1,795	$4,311,658	$0	$1,017,895	$1,501,433
31	13652654	0.05%	$416	$4,009,086	$8,000	$1,341,524	$1,637,030
31	14076315	1.85%	$580	$3,120	$2,800	$38	$0
31	14076390	1.85%	$580	$3,900	$2,800	$74	$0
31	14120843	4.03%	$540	$0	$4,000	$1,582	$0
31	28721000	3.12%	$1,746	$88,875	$0	$20,357	$36,932
31	28722945	2.77%	$1,746	$19,750	$0	$30,439	$42,025
31	28723015	3.50%	$1,746	$19,750	$0	$34,684	$48,319
31	28723025	6.22%	$1,746	$24,688	$0	$45,209	$66,420
31	28723089	3.05%	$1,746	$24,688	$0	$29,985	$42,641
31	28723096	2.70%	$1,746	$24,688	$0	$28,439	$40,165
31	28751903	7.47%	$1,746	$90,554	$0	$11,726	$31,828
31	28751905	0.00%	$383	$85,969	$8,000	$37,876	$45,399
31	28751908	2.92%	$1,746	$90,554	$0	$20,936	$37,447
31	28752075	4.20%	$1,746	$88,875	$0	$17,173	$34,647
31	28752207	0.00%	$383	$65,625	$8,000	$29,919	$35,856
31	28752913	3.29%	$1,746	$79,000	$0	$20,466	$36,655
31	28754863	3.84%	$1,746	$79,000	$0	$19,167	$35,974
31	28754900	2.89%	$1,746	$138,250	$0	$19,989	$39,552
31	28754908	6.44%	$1,746	$138,250	$0	$5,202	$22,681
31	28754915	3.14%	$1,746	$138,250	$0	$18,494	$37,910
31	28754931	1.86%	$1,746	$138,250	$0	$30,800	$50,969

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES ON ISSUE 2.2

Job #	Asset Identifier	Failure Probability	Direct Cost ($)	Indirect Cost ($)		PV (2015 Cost of Deviation from Optimal) ($)	2012 Cost of Deviation from Optimal ($)
				Customer Interruption Cost ($)	Other Indirect Cost ($)		
31	28754944	2.06%	$1,746	$138,250	$0	$28,100	$48,147
31	28754960	2.17%	$1,746	$138,250	$0	$27,066	$47,053
31	28755102	3.36%	$1,746	$138,250	$0	$16,753	$36,038
31	28791803	2.55%	$1,746	$88,875	$0	$22,611	$38,704
31	28797749	0.77%	$383	$9,375	$8,000	$4,539	$6,371
31	30313599	5.64%	$1,746	$138,250	$0	$7,502	$25,453
31	30313780	0.81%	$1,746	$138,250	$0	$53,214	$73,999
31	30313945	1.13%	$1,746	$88,875	$0	$33,877	$48,781
31	30313982	2.55%	$1,746	$88,875	$0	$22,601	$38,696
31	30314047	2.71%	$1,746	$88,875	$0	$22,023	$38,248
31	30314150	5.48%	$1,746	$79,000	$0	$16,554	$35,210
31	30314293	2.66%	$1,746	$69,125	$0	$22,709	$37,486
31	30315710	4.86%	$1,746	$69,125	$0	$19,748	$37,627
31	30315920	3.59%	$1,746	$90,554	$0	$18,695	$35,731
31	30315929	2.45%	$1,746	$90,554	$0	$23,043	$39,178
31	30316031	0.32%	$1,746	$138,250	$0	$76,380	$97,452
31	30316172	0.72%	$1,746	$138,250	$0	$56,266	$77,101
31	30316292	1.13%	$1,746	$138,250	$0	$44,233	$64,830
31	30316403	2.68%	$1,746	$88,875	$0	$22,106	$38,312
31	30316432	2.62%	$1,746	$90,554	$0	$22,342	$38,617
31	30316454	4.18%	$1,746	$88,875	$0	$17,207	$34,665
31	30316504	2.05%	$1,746	$79,000	$0	$25,100	$39,902
31	30316542	2.67%	$1,746	$79,000	$0	$22,499	$37,989
31	30316574	2.80%	$1,746	$79,000	$0	$21,886	$37,523
31	30316609	1.12%	$1,746	$79,000	$0	$32,086	$45,837
31	30316770	0.73%	$1,746	$69,125	$0	$34,227	$46,294

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES ON ISSUE 2.2

Job #	Asset Identifier	Failure Probability	Direct Cost ($)	Indirect Cost ($)		PV (2015 Cost of Deviation from Optimal) ($)	2012 Cost of Deviation from Optimal ($)
				Customer Interruption Cost ($)	Other Indirect Cost ($)		
31	30316861	2.48%	$1,746	$69,125	$0	$23,309	$37,838
31	30316943	3.65%	$1,746	$88,875	$0	$18,660	$35,677
31	30317013	1.73%	$1,746	$88,875	$0	$27,837	$43,245
31	30317103	4.01%	$1,746	$90,554	$0	$17,363	$34,730
31	30317152	3.13%	$1,746	$90,554	$0	$20,280	$36,954
31	30317205	3.40%	$1,746	$90,554	$0	$19,151	$36,043
31	30317264	3.79%	$1,746	$138,250	$0	$14,173	$33,210
31	30317523	3.43%	$1,746	$88,875	$0	$19,168	$36,002
31	30317557	5.38%	$1,746	$90,554	$0	$14,765	$33,217
31	30317645	1.86%	$1,746	$88,875	$0	$26,793	$42,310
31	30317682	2.99%	$1,746	$88,875	$0	$20,762	$37,224
31	30317899	4.94%	$1,746	$138,250	$0	$9,803	$28,163
31	30317930	10.15%	$1,746	$88,875	$0	$10,038	$32,501
31	30420284	0.35%	$383	$28,125	$8,000	$9,628	$12,677
31	30532153	0.00%	$383	$18,750	$8,000	$11,803	$14,097
31	30533803	0.00%	$383	$18,750	$8,000	$11,787	$14,076
31	30533807	2.68%	$783	$0	$4,000	$12,929	$20,235
31	30535665	0.27%	$540	$0	$4,000	$7,514	$10,241
31	30535695	4.01%	$783	$0	$4,000	$8,568	$14,528
31	30535697	3.18%	$540	$0	$4,000	$545	$0
31	30535729	3.18%	$540	$0	$4,000	$545	$0
31	30536481	6.39%	$540	$0	$4,000	$4,250	$0
31	30539408	0.00%	$1,746	$79,000	$0	$64,491	$77,498
31	30541600	0.00%	$1,746	$79,000	$0	$64,489	$77,492
31	30541993	0.00%	$383	$131,250	$8,000	$56,984	$68,053
31	30543537	0.00%	$383	$84,375	$8,000	$38,156	$45,570

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES ON ISSUE 2.2

Job #	Asset Identifier	Failure Probability	Direct Cost ($)	Indirect Cost ($)		PV (2015 Cost of Deviation from Optimal) ($)	2012 Cost of Deviation from Optimal ($)
				Customer Interruption Cost ($)	Other Indirect Cost ($)		
31	30543568	0.00%	$383	$84,375	$8,000	$38,153	$45,565
31	30544086	0.00%	$383	$84,375	$8,000	$38,150	$45,560
31	30544229	0.00%	$1,746	$88,875	$0	$71,716	$86,223
31	30544359	0.00%	$1,746	$88,875	$0	$71,716	$86,158
31	30546910	0.00%	$383	$85,969	$8,000	$38,789	$46,322
31	30549792	0.00%	$383	$85,969	$8,000	$38,790	$46,323
31	30549811	0.00%	$383	$85,969	$8,000	$38,789	$46,322
31	30552398	0.00%	$383	$85,969	$8,000	$38,796	$46,333
31	30559161	0.17%	$1,746	$88,875	$0	$58,877	$72,978
31	30559169	0.17%	$1,746	$88,875	$0	$58,935	$73,036
31	30564864	0.15%	$1,746	$88,875	$0	$60,498	$74,576
32	13623107	0.04%	$214	$2,550,909	$8,000	$1,372,089	$1,655,790
32	13623869	4.96%	$1,592	$2,842,442	$0	$146,199	$414,756
32	13623897	1.42%	$1,592	$2,842,442	$0	$1,207,334	$1,713,092
32	13624605	1.06%	$1,746	$691,250	$0	$263,396	$360,649
32	13624751	16.58%	$1,592	$2,842,442	$0	$890,608	$0
32	13625420	22.69%	$1,592	$2,842,442	$0	$1,429,258	$0
32	13628274	0.04%	$214	$2,550,909	$8,000	$1,379,265	$1,662,951
32	13628498	0.04%	$214	$2,550,909	$8,000	$1,378,504	$1,662,167
32	13631190	0.12%	$214	$2,550,909	$8,000	$1,277,844	$1,558,759
32	13631300	0.04%	$214	$2,550,909	$8,000	$1,380,111	$1,663,822
32	13631417	0.04%	$214	$2,550,909	$8,000	$1,378,081	$1,661,731
32	13635573	0.10%	$1,795	$4,450,489	$0	$2,342,323	$3,027,453
32	13636187	8.20%	$2,233	$1,260,000	$0	$107,296	$0
32	13636423	3.23%	$1,592	$2,599,740	$0	$438,650	$787,075
32	13637553	0.69%	$383	$95,344	$8,000	$20,375	$28,492

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES ON ISSUE 2.2

Job #	Asset Identifier	Failure Probability	Direct Cost ($)	Indirect Cost ($)		PV (2015 Cost of Deviation from Optimal) ($)	2012 Cost of Deviation from Optimal ($)
				Customer Interruption Cost ($)	Other Indirect Cost ($)		
32	13646565	6.72%	$1,592	$2,842,442	$0	$0	$154,941
32	13649374	0.09%	$1,592	$2,599,740	$0	$2,186,933	$2,767,037
32	13650454	7.87%	$1,592	$2,842,442	$0	$12,002	$73,078
32	13653648	1.89%	$383	$234,281	$8,000	$8,443	$19,867
32	14064700	12.15%	$289	$0	$5,000	$880,682	$0
32	14076802	0.43%	$580	$649,615	$2,800	$7,252	$0
32	14077929	3.35%	$580	$606,388	$2,800	$57,758	$0
32	14077954	3.35%	$580	$606,388	$2,800	$57,758	$0
32	14078591	0.43%	$580	$554,611	$2,800	$5,951	$0
32	28715648	12.15%	$289	$0	$5,000	$880,682	$0
32	28736684	1.11%	$214	$2,333,100	$8,000	$464,973	$683,452
32	28828845	145.02%	$1,746	$148,125	$0	$0	$0
32	30316477	3.25%	$214	$2,550,909	$8,000	$45,256	$166,410
32	30316479	0.10%	$214	$2,333,100	$8,000	$1,100,196	$1,367,103
32	30316480	0.38%	$214	$2,550,909	$8,000	$939,040	$1,211,111
32	30379199	12.15%	$289	$0	$5,000	$880,682	$0
32	30379281	14.46%	$383	$0	$5,000	$1,782,620	$0
32	30445262	48.92%	$383	$332,906	$8,000	$0	$0
32	30445334	7.68%	$776	$2,230,224	$5,000	$480,659	$0
32	30445342	16.02%	$383	$70,313	$8,000	$0	$0
32	30445362	0.17%	$214	$2,550,909	$8,000	$1,187,456	$1,468,872
32	30445363	0.14%	$214	$2,550,909	$8,000	$1,230,069	$1,512,196
32	30445429	0.00%	$383	$248,438	$8,000	$108,420	$132,065
32	30457089	2.72%	$1,592	$2,842,442	$0	$635,099	$1,044,391
33	13618264	0.46%	$720	$75,000	$8,000	$12,703	$17,864
33	13619078	5.65%	$1,592	$4,437,883	$0	$41,110	$312,463

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES ON ISSUE 2.2

Job #	Asset Identifier	Failure Probability	Direct Cost ($)	Indirect Cost ($)		PV (2015 Cost of Deviation from Optimal) ($)	2012 Cost of Deviation from Optimal ($)
				Customer Interruption Cost ($)	Other Indirect Cost ($)		
33	13619319	0.79%	$214	$3,982,716	$8,000	$985,365	$1,392,178
33	13620415	0.03%	$214	$3,982,716	$8,000	$2,176,471	$2,620,317
33	13620651	0.07%	$383	$112,500	$8,000	$44,574	$55,312
33	13621174	0.04%	$383	$4,688	$8,000	$6,840	$8,254
33	13621520	0.61%	$214	$3,982,716	$8,000	$1,166,134	$1,584,721
33	13621592	0.02%	$214	$3,982,716	$8,000	$2,188,023	$2,633,454
33	13621731	62.44%	$1,592	$4,437,883	$0	$7,757,454	$0
33	13622590	0.01%	$214	$3,982,716	$8,000	$2,200,058	$2,643,271
33	13623079	13.25%	$1,592	$4,437,883	$0	$1,022,838	$0
33	13623346	0.14%	$214	$3,982,716	$8,000	$1,897,778	$2,338,996
33	13624455	0.71%	$383	$154,688	$8,000	$28,486	$40,395
33	13624752	0.17%	$214	$3,982,716	$8,000	$1,770,570	$2,220,030
33	13625030	0.10%	$214	$3,982,716	$8,000	$2,002,203	$2,444,470
33	13625608	0.01%	$214	$3,982,716	$8,000	$2,200,332	$2,643,614
33	13625739	0.89%	$214	$3,982,716	$8,000	$882,608	$1,277,656
33	13625908	0.12%	$214	$3,982,716	$8,000	$1,883,167	$2,332,090
33	13626411	0.22%	$383	$9,375	$8,000	$18,078	$22,120
33	13626438	0.25%	$214	$3,982,716	$8,000	$1,669,018	$2,106,381
33	13626509	0.15%	$214	$3,982,716	$8,000	$1,867,878	$2,308,722
33	13626846	0.34%	$214	$3,982,716	$8,000	$1,509,407	$1,942,554
33	13626885	0.55%	$383	$112,500	$8,000	$27,144	$38,219
33	13626909	0.12%	$214	$3,982,716	$8,000	$1,984,429	$2,422,187
33	13627017	1.42%	$214	$3,982,716	$8,000	$578,632	$918,679
33	13627121	0.30%	$214	$3,982,716	$8,000	$1,578,725	$2,012,481
33	13627692	0.21%	$214	$3,982,716	$8,000	$1,736,483	$2,175,234
33	13627789	0.02%	$214	$3,982,716	$8,000	$2,186,807	$2,629,619

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES ON ISSUE 2.2

Job #	Asset Identifier	Failure Probability	Direct Cost ($)	Indirect Cost ($)		PV (2015 Cost of Deviation from Optimal) ($)	2012 Cost of Deviation from Optimal ($)
				Customer Interruption Cost ($)	Other Indirect Cost ($)		
33	13628216	0.10%	$214	$3,982,716	$8,000	$1,996,253	$2,438,466
33	13628418	0.07%	$214	$3,982,716	$8,000	$2,058,074	$2,500,847
33	13628718	0.63%	$214	$3,982,716	$8,000	$1,138,985	$1,555,940
33	13629346	0.15%	$214	$3,982,716	$8,000	$1,884,136	$2,325,188
33	13629545	0.02%	$214	$3,982,716	$8,000	$2,185,971	$2,628,757
33	13630531	0.12%	$214	$3,982,716	$8,000	$1,881,779	$2,330,713
33	13631489	22.29%	$1,592	$4,437,883	$0	$2,331,977	$0
33	13632307	0.86%	$383	$154,688	$8,000	$22,605	$33,695
33	13633147	0.36%	$214	$3,982,716	$8,000	$1,481,319	$1,913,574
33	13633381	0.16%	$214	$3,982,716	$8,000	$1,795,823	$2,245,206
33	13634108	0.51%	$214	$3,982,716	$8,000	$1,276,912	$1,701,157
33	13635138	0.04%	$214	$3,982,716	$8,000	$2,122,646	$2,568,940
33	13635202	0.84%	$214	$3,982,716	$8,000	$901,638	$1,329,836
33	13635642	2.40%	$383	$154,688	$8,000	$3,592	$10,623
33	13636600	0.59%	$214	$3,982,716	$8,000	$1,078,861	$1,504,269
33	13638129	0.35%	$214	$3,982,716	$8,000	$1,432,467	$1,879,980
33	13638462	0.02%	$214	$3,982,716	$8,000	$2,175,230	$2,617,690
33	13638976	0.07%	$214	$3,982,716	$8,000	$2,072,092	$2,514,992
33	13639151	0.36%	$214	$3,982,716	$8,000	$1,538,905	$1,961,835
33	13639628	0.76%	$383	$46,875	$8,000	$9,405	$13,470
33	13639996	4.23%	$214	$3,982,716	$8,000	$2,384	$69,730
33	13640397	0.14%	$214	$3,982,716	$8,000	$1,884,869	$2,325,930
33	13640553	1.14%	$214	$3,982,716	$8,000	$722,998	$1,105,310
33	13640578	0.76%	$1,746	$34,563	$0	$84,051	$103,241
33	13640812	0.02%	$214	$3,982,716	$8,000	$2,188,456	$2,632,198
33	13641043	1.00%	$214	$3,982,716	$8,000	$812,070	$1,204,161

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES ON ISSUE 2.2

Job #	Asset Identifier	Failure Probability	Direct Cost ($)	Indirect Cost ($)		PV (2015 Cost of Deviation from Optimal) ($)	2012 Cost of Deviation from Optimal ($)
				Customer Interruption Cost ($)	Other Indirect Cost ($)		
33	13641094	0.07%	$214	$3,982,716	$8,000	$2,013,911	$2,458,585
33	13641782	0.70%	$214	$3,982,716	$8,000	$1,103,087	$1,498,940
33	13641783	2.21%	$214	$3,982,716	$8,000	$257,804	$527,993
33	13641807	35.90%	$1,746	$39,500	$0	$0	$9,626
33	13642297	0.94%	$214	$3,982,716	$8,000	$862,016	$1,258,811
33	13642742	26.73%	$1,592	$4,437,883	$0	$2,806,306	$0
33	13643181	0.06%	$720	$112,500	$8,000	$30,057	$36,918
33	13643472	1.04%	$214	$3,982,716	$8,000	$786,824	$1,176,145
33	13643758	0.01%	$214	$3,982,716	$8,000	$2,200,418	$2,643,704
33	13643786	0.98%	$214	$3,982,716	$8,000	$832,300	$1,226,102
33	13643839	30.55%	$1,592	$4,437,883	$0	$3,336,299	$0
33	13644285	0.02%	$214	$3,982,716	$8,000	$2,205,825	$2,651,021
33	13644330	7.30%	$1,592	$4,437,883	$0	$162,781	$0
33	13645597	0.29%	$1,592	$4,437,883	$0	$3,410,671	$4,278,097
33	13645685	0.03%	$214	$3,982,716	$8,000	$2,172,966	$2,616,126
33	13645751	4.82%	$214	$3,982,716	$8,000	$43,375	$18,688
33	13645800	1.13%	$214	$3,982,716	$8,000	$729,260	$1,112,324
33	13646687	0.26%	$214	$3,982,716	$8,000	$1,647,442	$2,084,314
33	13647115	0.04%	$214	$3,982,716	$8,000	$2,150,387	$2,593,296
33	13647383	0.24%	$214	$3,982,716	$8,000	$1,687,041	$2,124,794
33	13647897	0.02%	$214	$3,982,716	$8,000	$2,194,613	$2,639,957
33	13647923	3.34%	$1,592	$4,437,883	$0	$450,027	$913,669
33	13648174	0.54%	$214	$3,982,716	$8,000	$1,236,571	$1,658,858
33	13649592	0.67%	$214	$3,982,716	$8,000	$1,101,940	$1,516,665
33	13650057	0.49%	$383	$154,688	$8,000	$36,128	$48,566
33	13650406	0.46%	$1,746	$49,375	$0	$30,361	$38,383

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES ON ISSUE 2.2

Job #	Asset Identifier	Failure Probability	Direct Cost ($)	Indirect Cost ($)		PV (2015 Cost of Deviation from Optimal) ($)	2012 Cost of Deviation from Optimal ($)
				Customer Interruption Cost ($)	Other Indirect Cost ($)		
33	13651164	0.32%	$214	$3,982,716	$8,000	$1,550,366	$1,984,747
33	13651711	0.24%	$214	$3,982,716	$8,000	$1,616,808	$2,066,104
33	13651825	0.02%	$214	$3,982,716	$8,000	$2,185,355	$2,628,122
33	13652013	0.31%	$214	$3,982,716	$8,000	$1,558,361	$1,992,949
33	13652146	0.02%	$214	$3,982,716	$8,000	$2,189,483	$2,632,933
33	13652781	0.04%	$214	$3,982,716	$8,000	$2,151,335	$2,594,256
33	13652844	0.03%	$214	$3,982,716	$8,000	$2,176,774	$2,620,622
33	13653491	0.11%	$214	$3,982,716	$8,000	$1,964,813	$2,406,740
33	13653688	0.94%	$214	$3,982,716	$8,000	$838,650	$1,229,580
33	13670757	0.15%	$214	$3,982,716	$8,000	$1,873,026	$2,313,937
33	14068274	2.52%	$289	$0	$5,000	$287,938	$0
33	14068746	9.29%	$289	$0	$5,000	$1,076,976	$0
33	14075281	3.44%	$239	$0	$4,500	$413,315	$0
33	14075296	2.63%	$816	$3,336,378	$2,600	$253,589	$0
33	14075297	3.44%	$239	$0	$4,500	$413,315	$0
33	14075299	3.44%	$239	$0	$4,500	$413,315	$0
33	14075314	2.63%	$816	$3,336,378	$2,600	$253,589	$0
33	14075316	3.44%	$239	$0	$4,500	$413,315	$0
33	14075429	3.44%	$239	$0	$4,500	$413,315	$0
33	14118883	1.86%	$540	$0	$2,000	$8,230	$12,931
33	14118904	1.86%	$540	$0	$2,000	$8,230	$12,931
33	14118905	4.47%	$540	$0	$2,000	$3,293	$5,822
33	14118908	0.91%	$540	$0	$2,000	$13,494	$19,226
33	14118919	1.05%	$540	$0	$2,000	$12,600	$17,083
33	14119513	5.37%	$540	$0	$2,000	$4,832	$0
33	14129791	4.03%	$540	$0	$4,000	$718	$1,597

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES ON ISSUE 2.2

Job #	Asset Identifier	Failure Probability	Direct Cost ($)	Indirect Cost ($)		PV (2015 Cost of Deviation from Optimal) ($)	2012 Cost of Deviation from Optimal ($)
				Customer Interruption Cost ($)	Other Indirect Cost ($)		
33	14129792	4.03%	$540	$0	$4,000	$718	$1,597
33	14129793	4.03%	$540	$0	$4,000	$718	$1,597
33	14129847	4.03%	$540	$0	$4,000	$718	$1,597
33	14130365	4.03%	$540	$0	$4,000	$718	$1,597
33	14130368	8.41%	$540	$0	$4,000	$515	$0
33	14130448	4.03%	$540	$0	$4,000	$718	$1,597
33	14131011	8.41%	$540	$0	$4,000	$515	$0
33	14131026	6.02%	$540	$0	$4,000	$0	$301
33	14131027	0.14%	$540	$0	$4,000	$6,329	$8,369
33	14131028	6.02%	$540	$0	$4,000	$123	$80
33	14131029	8.41%	$540	$0	$4,000	$515	$0
33	14131137	5.66%	$540	$0	$4,000	$56	$462
33	14131186	0.93%	$540	$0	$4,000	$5,199	$7,606
33	28107101	0.54%	$214	$3,982,716	$8,000	$1,187,674	$1,629,356
33	28698081	9.29%	$214	$0	$5,000	$1,902,244	$0
33	28698297	50.97%	$1,592	$4,437,883	$0	$6,165,831	$0
33	28698328	0.82%	$1,592	$4,437,883	$0	$2,665,745	$3,466,918
33	28699433	0.27%	$383	$65,625	$8,000	$21,289	$27,146
33	28700678	0.70%	$1,746	$69,125	$0	$92,448	$115,199
33	28701251	0.38%	$383	$65,625	$8,000	$18,905	$24,716
33	28744206	14.46%	$458	$0	$5,000	$86,924	$0
33	28744752	0.01%	$383	$65,625	$8,000	$29,234	$35,156
33	28744861	0.01%	$383	$65,625	$8,000	$29,305	$35,227
33	28758579	0.56%	$720	$45,000	$8,000	$9,775	$13,752
33	28779993	0.51%	$383	$32,813	$8,000	$9,064	$12,230
33	28779997	10.50%	$1,746	$34,563	$0	$5,418	$13,698

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES ON ISSUE 2.2

Job #	Asset Identifier	Failure Probability	Direct Cost ($)	Indirect Cost ($)		PV (2015 Cost of Deviation from Optimal) ($)	2012 Cost of Deviation from Optimal ($)
				Customer Interruption Cost ($)	Other Indirect Cost ($)		
33	28780022	5.45%	$1,746	$34,563	$0	$7,965	$15,112
33	28780026	2.26%	$1,746	$34,563	$0	$13,082	$19,512
33	28780029	19.12%	$1,746	$34,563	$0	$3,864	$14,075
33	28781603	0.79%	$1,746	$106,156	$0	$110,062	$139,075
33	28785877	0.58%	$383	$46,875	$8,000	$11,246	$15,427
33	28785899	11.05%	$1,746	$49,375	$0	$865	$6,767
33	28785901	0.48%	$1,746	$49,375	$0	$30,065	$38,083
33	28785905	5.31%	$1,746	$49,375	$0	$5,665	$12,715
33	28785909	9.76%	$1,746	$49,375	$0	$1,631	$7,792
33	28785912	0.38%	$1,746	$49,375	$0	$31,983	$40,022
33	28785914	10.41%	$1,746	$49,375	$0	$1,428	$7,458
33	28786178	0.27%	$383	$46,875	$8,000	$16,442	$20,924
33	28786184	0.03%	$383	$46,875	$8,000	$21,689	$26,144
33	28786188	0.02%	$383	$46,875	$8,000	$21,757	$26,213
33	28809255	0.15%	$383	$4,688	$8,000	$5,898	$7,291
33	28834449	13.86%	$1,592	$4,437,883	$0	$1,110,520	$0
33	28834472	27.61%	$1,592	$4,437,883	$0	$3,105,077	$0
33	28834767	10.20%	$1,592	$4,437,883	$0	$581,717	$0
33	28834855	12.01%	$1,592	$4,437,883	$0	$843,938	$0
33	28834880	13.88%	$1,592	$4,437,883	$0	$1,113,615	$0
33	28834884	10.83%	$1,592	$4,437,883	$0	$673,387	$0
33	28834893	16.36%	$1,592	$4,437,883	$0	$1,473,511	$0
33	28834953	9.72%	$1,746	$222,484	$0	$26,724	$0
33	28835105	9.72%	$1,746	$222,484	$0	$22,298	$0
33	28835240	15.93%	$1,746	$222,484	$0	$58,671	$0
33	28835249	16.20%	$1,746	$222,484	$0	$60,274	$0

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES ON ISSUE 2.2

Job #	Asset Identifier	Failure Probability	Direct Cost ($)	Indirect Cost ($)		PV (2015 Cost of Deviation from Optimal) ($)	2012 Cost of Deviation from Optimal ($)
				Customer Interruption Cost ($)	Other Indirect Cost ($)		
33	28835263	5.64%	$1,746	$222,484	$0	$1,055	$5,499
33	28835323	13.69%	$1,746	$222,484	$0	$45,561	$0
33	28835637	30.31%	$1,592	$4,437,883	$0	$3,497,562	$0
33	28835648	12.08%	$1,592	$4,437,883	$0	$853,044	$0
33	28835660	20.59%	$1,592	$4,437,883	$0	$2,085,986	$0
33	28835662	27.58%	$1,592	$4,437,883	$0	$3,100,761	$0
33	28835851	12.35%	$1,592	$4,437,883	$0	$893,247	$0
33	28835892	18.29%	$1,592	$4,437,883	$0	$1,752,780	$0
33	28835967	7.93%	$1,592	$4,437,883	$0	$254,113	$0
33	28836070	23.74%	$1,592	$4,437,883	$0	$2,543,236	$0
33	28836094	10.40%	$1,592	$4,437,883	$0	$610,895	$0
33	28836107	9.01%	$1,592	$4,437,883	$0	$409,452	$0
33	28836117	14.14%	$1,592	$4,437,883	$0	$1,151,444	$0
33	28836125	9.03%	$1,746	$118,500	$0	$3,379	$1,460
33	28836234	9.02%	$1,746	$118,500	$0	$3,357	$1,467
33	28836257	17.00%	$1,746	$118,500	$0	$31,630	$0
33	28836303	41.26%	$1,746	$118,500	$0	$103,926	$0
33	28836305	21.28%	$1,746	$118,500	$0	$44,390	$0
33	28836331	28.27%	$1,592	$4,437,883	$0	$3,199,862	$0
33	30530412	0.00%	$214	$3,982,716	$8,000	$2,282,491	$2,740,961
33	30530413	0.00%	$214	$3,982,716	$8,000	$2,278,077	$2,741,605
33	30530817	0.37%	$1,746	$49,375	$0	$32,096	$40,136
33	30530830	0.40%	$1,746	$49,375	$0	$31,512	$39,546
33	30592706	0.55%	$214	$3,982,716	$8,000	$1,230,386	$1,652,346
34	1669827	0.01%	$720	$783,750	$8,000	$194,164	$233,172
34	1670319	0.00%	$720	$783,750	$8,000	$195,348	$234,343

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES ON ISSUE 2.2

Job #	Asset Identifier	Failure Probability	Direct Cost ($)	Indirect Cost ($)		PV (2015 Cost of Deviation from Optimal) ($)	2012 Cost of Deviation from Optimal ($)
				Customer Interruption Cost ($)	Other Indirect Cost ($)		
34	1673663	0.00%	$416	$791,820	$8,000	$299,173	$358,247
34	1675400	0.01%	$720	$783,750	$8,000	$192,103	$231,135
34	1676553	0.01%	$720	$783,750	$8,000	$190,468	$229,518
34	1684620	0.15%	$383	$4,688	$8,000	$6,517	$8,108
34	1686447	1.15%	$1,746	$61,719	$0	$38,210	$54,127
34	1686779	2.26%	$1,746	$4,938	$0	$34,130	$43,046
34	1687474	0.00%	$720	$93,750	$8,000	$27,385	$32,877
34	1688654	0.13%	$383	$4,688	$8,000	$6,431	$7,972
34	1692758	14.82%	$1,746	$9,875	$0	$10,027	$16,633
34	1700184	0.00%	$180	$2,150,460	$8,000	$1,341,583	$1,621,216
34	1702735	1.18%	$1,746	$61,719	$0	$38,275	$54,302
34	1703680	1.28%	$1,746	$61,719	$0	$38,507	$55,062
34	1705356	2.67%	$1,746	$4,938	$0	$39,166	$49,430
34	1742171	3.18%	$540	$0	$4,000	$3,700	$0
34	1742172	3.74%	$540	$0	$4,000	$4,966	$0
34	1742174	3.18%	$540	$0	$4,000	$3,623	$0
34	1742175	0.09%	$540	$0	$4,000	$6,356	$10,280
34	1746699	4.65%	$540	$0	$4,000	$387	$1,086
34	1746700	4.65%	$540	$0	$4,000	$387	$1,086
34	28122996	82.20%	$1,558	$2,419,268	$0	$5,854,797	$0
34	28165911	1.06%	$1,746	$61,719	$0	$37,921	$53,354
34	28167695	0.53%	$180	$2,150,460	$8,000	$759,713	$1,027,257
34	28167734	1.14%	$1,746	$61,719	$0	$36,149	$51,457
34	28841503	1.39%	$1,746	$61,719	$0	$38,788	$55,937
34	30300128	1.27%	$1,746	$61,719	$0	$38,484	$55,009
34	30506479	12.44%	$1,746	$9,875	$0	$9,373	$15,284

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES ON ISSUE 2.2

Job #	Asset Identifier	Failure Probability	Direct Cost ($)	Indirect Cost ($)		PV (2015 Cost of Deviation from Optimal) ($)	2012 Cost of Deviation from Optimal ($)
				Customer Interruption Cost ($)	Other Indirect Cost ($)		
34	30506539	0.00%	$1,746	$9,875	$0	$72,568	$88,085
Total						$856,603,977	$841,647,610